Enclosure 2

This exhibit was not previously submitted in November 2023

Exhibit 7.01

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https://lufkindailynews.com/news/local/pa-prospect-corporation-deemed-administratively-complete/article_308f97fc-125c-5147-a70f-fbe771966f37.html

FEATURED

PA Prospect Corporation deemed 'administratively

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Several San Augustine residents are seeking help as the fight to keep a Montana-based non-hazardous oil and gas waste facility in San Augustine County out of their backyards amps up.

The application submitted by PA Prospect Corporation of Columbus, Montana, seeking to construct a facility to store, handle, treat, and dispose of non-hazardous oil & gas (O&G) waste was deemed administratively complete by the Railroad Commission of Texas, said Andrew Keese, a spokesperson for the RRC.

“The application was referred to the Railroad Commission’s Hearings Division,” he said.

A hearing for the company’s proposal was not set by Friday afternoon.

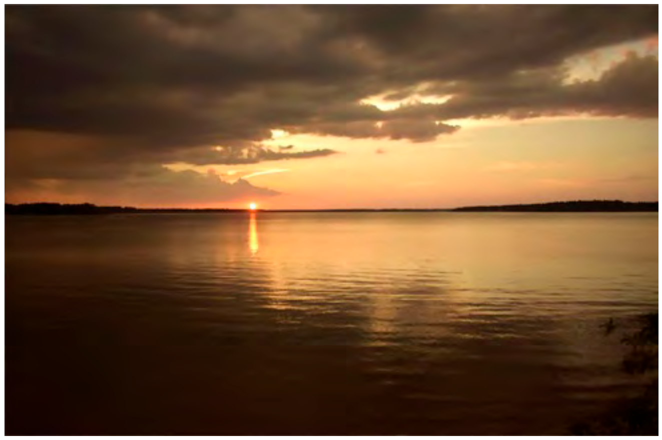
The facility sits on top of the headwaters of the Sam Rayburn Reservoir. Residents are concerned about the long-term effects an operation like this will have on the lake and the land surrounding their homes.

“They cannot guarantee it’s not going to damage that lake,” San Augustine resident Ann Bridges said. “(PA Prospect’s) lawyer told us in February that we wouldn’t see it. … He’s thinking they’ll have a tree row between us. It doesn’t matter if I see it, I’m going to smell it, those lights are going to be on 24/7 and I’m going to hear it because that traffic is going to run 24/7 unless they don’t have any business.

“Our quiet little country road is never going to be the same.”

Bridges lives next door to where the facility would be located. She set up a GoFundMe fundraiser in an attempt to get help in fighting this company. Bridges and her fellow supporters have secured an attorney from Austin to help but expect the fight to get much more expensive.

They’re attempting to raise $15,000.



The sun sets over Sam Rayburn Reservoir in this July file photo. The PA Prospect Company is applying for a permit with the Texas Railroad Commission in hopes of building an oil and gas waste landfill in the headwaters of Sam Rayburn Reservoir. The geologist involved in the application is facing scrutiny by the Texas Board of Geoscientists for her work on this application.
JESS HUFF/The Lufkin Daily News

“The $15000 is not the total cost, but figured that's where we would start,” Bridges’ stated on the fundraiser’s page. “It's expensive and it's about to get real expensive. All funds received will go for legal fees.”

State Rep. Trent Ashby and Sen. Robert Nichols are drafting a legislative proposal that would require the Texas Railroad Commission to put a greater emphasis on protecting water quality in their permitting process.

This proposal will be submitted in the next legislative session, which is slated to begin in January 2021.

Jess Huff's email address is **jess.huff@lufkindailynews.com.**

Exhibit 7.02

This exhibit was not previously submitted in November 2023

https://lufkindailynews.com/news/local/experts-share-concerns-as-decision-on-pa-prospect-looms/article_f71c7bdd-7e71-51ed-b99f-f364aefe546b.html

FEATURED

Experts share concerns as decision on PA Prospect looms

By JESS HUFF/The Lufkin Daily News
May 1, 2021

Sunrise catches the fog rolling off the flashes of farmlands between the tall pines of Deep East Texas along state Highway 103 east inviting drivers to slow down, breathe deep and take a sip of gas station coffee.

East Texans take pride in their homes in the heart of the state's rainiest region; rural life offers peace to individuals disinterested in the hustle and bustle of the state's urban areas. And they don't take kindly to people threatening the quality of their lives.

As such, countless East Texans, including state Sen. Robert Nichols and state Rep. Trent Ashby, took up the fight against a Montana-based company that applied for a permit to construct a surface oil and gas waste facility in the Chinquapin Community of San Augustine County.

PA Prospect LLC's permit will face the scrutiny of the Texas Railroad Commissioners in a two-week hearing starting Tuesday.

Members of the Chinquapin Community and several others will make their final arguments to stop the facility at that time. They've been here before. The same company was granted a permit for a Class II injection well at the same property in 2019, according to Jay Stewart, the company's legal representative.

The community brings with it the experience of losing that battle, resident RD Griffin said. Ann Bridges, whose property abuts PA Prospect's, raised money to bring in Austin-based attorneys to fight this battle.

This community isn't opposed to the oil and gas industry; they don't like the threat of a fully functioning 256.7-acre facility straddling two tributaries of Sam Rayburn Reservoir.

Bridges doesn't want to live next to another facility like this — she moved from the coast to escape this exact problem, she said in a July 2020 interview. She and her neighbors aren't thrilled about the air and noise pollution they fear it will inevitably bring; not to mention the impact continuous truck traffic will have on the highway.

Keith Dubose, whose property is east of the proposed facility, is concerned because he relies on a private well and Caney Creek, which runs through the PA Prospect property, runs within 30 yards of his home.

"I know what type of nice smells you get off of the top of oil residue that would be coming through on my front porch drinking coffee every morning because it is to the west of me," he said in a pre-hearing conference in December.

These are not concerns the railroad commission has considered in the past. A similar fight in 2016 caught state and national attention as the 300 residents of Nordheim fought to prevent a similar facility from being constructed across the street from a school.

The PA Prospect application

Dubose, whose private well is 200 feet deep, expressed concern about what a breach of the leachate system would mean for his water source.

PA Prospect, for its part, guarantees the facility would not pose a threat to the water quality in the region.

Stewart, who has represented clients like PA Prospect for 25 years, doesn't believe the oil and gas waste stream should be confused with hazardous waste. It's different because the Texas Commission on Environmental Quality regulates hazardous waste that "is generally the result of manufacturing processes and formulating chemicals for industrial and commercial production," he said.

"Unfortunately, prior to the 1980s, East Texas experienced oil and gas drilling and production for many decades with less rigorous industry practices regarding disposal of the waste. Many of those historical East Texas sites are currently being remediated under the watchful eye of the RRC."

PA Prospect's application states that, per liter, it would accept less than: five milligrams of arsenic, 100 milligrams of barium, one milligram of cadmium, five milligrams chromium, five milligrams of lead, 0.2 milligrams of mercury, one milligram of selenium, five milligrams of silver and 0.5 milligrams of benzene.

Health care professionals have classified several of these chemicals as known or probable human carcinogens, according to the Environmental Protection Agency.

Though the company, state and U.S. Environmental Protection Agency stand by the safety of disposal sites, the multitudes of East Texans who voiced opposition to PA Prospect, water conservation group leaders, researchers and more are skeptical.

"My concerns are water quality based," Kelley Holcomb, director of the Angelina & Neches River Authority, said.

The river authority is tasked by the state to respond to and remediate water quality issues caused by pollution. In his letter against the proposed facility, Holcomb pointed to agencies currently fixing several spots in the Ayish Bayou and Sam Rayburn Reservoir, which would be even more impacted if PA Prospect's facility failed to contain the waste.

"They're going to be disposing of material, both solids and liquids, drilling waste, oil field waste in some shape or form that has contaminants in it they aren't forced to disclose, No. 1," Holcomb said. "Two, science doesn't know what the overall impact is if they even were required to disclose it."

He pointed to the number of vehicles moving in and out and questioned whether the materials transported to the community would be well contained. He believes the potential for surface water impact is great.

And so do residents. Resident Phillip Carrico is concerned about what a leak would do to the water supply, the livestock and agriculture in his area and whether it would lower property values.

And while the concern for the facility's immediate impact is there, he is even more concerned about what happens when the facility is closed and dormant.

"How well will that facility be maintained?" he asked. "That's when the water quality issues are going to come."

His concerns extend to the two Class II injection well sites already approved by the commission, too. It's difficult to discern what's happening below ground and if the well technology were to fail, he said.

The impacts of a spill below ground could contaminate the Carrizo-Wilcox Aquifer, a massive sub-surface water source that extends from East Texas to the Texas border with Mexico.

"Once it becomes contaminated in a groundwater scenario, it's contaminated for a long period of time," Holcomb said. "Surface water, you can stop the flow; generally stop the contamination and the surface environment will recover pretty quickly. The environment below ground does not recover so quickly."

The railroad commission inspects these injection wells at a minimum of every five years, Andrew Keese, a spokesman for the commission, said. But this is not enough, Zhong Lu, a researcher for the Southern Methodist University who investigates geohazards in West Texas, said.

In three separate peer-reviewed studies, he indicated problems with the injection wells, including at one point the detection of a well in West Texas that caused the ground to rise around it.

His goal is to utilize technology to determine when and where the leaks are occurring and is currently watching a few others, though he was hesitant to give any more information until more evidence supports his findings.

He, too, is concerned about how even the newer wells will withstand the test of time, he said.

"Well, if it contaminated our water supply, it would — you know, we have two wells on our property, we have livestock, we have hay, and so forth — it would devastate us, potentially, Carrico said.

Railroad commission oversight

The Railroad Commission is guided by Statewide Rule 8, prohibiting the pollution of surface and sub-surface waterways in Texas. In addition to this provision, companies must adhere to construction guidelines, said Paul Dubois, head of technical permitting at the Railroad Commission.

“The RRC requires these wastes to be properly disposed of at facilities subject to its regulation,” Stewart said.

“New facilities are subject to strict regulation and scrutiny by state regulators, including ongoing requirements for environmentally protective engineering design and construction, inspection, financial assurance, closure planning and record keeping.”

Facilities will typically utilize synthetic liners installed to detect leaks and could have leachate collection systems that allow for some drainage from the cell into a collection zone, he said. The design must include how to cover the waste, closure requirements, what happens when the cell is full and how to maintain closure integrity for a period of time, he said.

“When they apply for a permit, there are several things they have to do to demonstrate that those activities will protect the environment,” Dubois said.

The railroad commission’s permitting process requires the agency to look at the hydro geological environment and the waste management units and how they were designed and will be built, and ensures other requirements of the application were met before the facility can operate. It is then also required to make quarterly or semi-annual filings recording the site’s activity.

“The information we receive mostly comes from either our knowledge and our information sources regarding geology and what the applicant provides in the application,” DuBois said. “We don’t, as part of the permitting process, receive information from third parties.”

But it’s exactly this type of information that led the commission to reject a permit proposed for a facility in West Texas, he said. A third-party geologist notified the agency of sinkholes in the area and the commission denied the application.

“Then, typically annually for a commercial facility, our district field inspectors will go out and inspect the facility again, with the permit in hand,” DuBois said.

Inspectors will look at: housekeeping, whether the place is well run, whether the waste makes it where it’s supposed to be, if the waste is being managed as required by the permit, and whether there is evidence of a spill.

“If there are violations, it can resort in enforcement,” DuBois said.

Evidence of this can be seen in the Aug. 15, 2021, penalties assessed by the railroad commissioners; they collected $660,000 in penalties. However, inspections on the state’s 66 active facilities listed by the agency on its website are not always regular.

Twelve facilities considered active showed no inspection records on "RRC Oil" the railroad commission's database. Twenty-three facilities show no inspections later than 2019 on RRC Oil.

And of those with recorded inspections, certain agencies had more than a few violations. For example: McBride Operating LLC in Harrison County had 19 violations across its recent history, including some listed by the Railroad Commission as "major."

Sojourner Drilling Corp. in Jones County in West Texas had 120 violations over 655 inspections in the six-year period posted online, according to the commission website. The same company name had nearly 400 violations over several counties through more than 2,000 inspections over a six-year-period.

Jess Huff's email address is **jess.huff@lufkindailynews.com.**

Exhibit 7.03

This exhibit was not previously submitted in November 2023

https://lufkindailynews.com/news/local/examiners-recommend-denial-of-pa-prospect-application/article_61a7a8a8-38c3-5132-9aef-6c377a2f87e8.html

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Examiners recommend denial of PA Prospect application

By JESS HUFF/The Lufkin Daily News
Mar 21, 2022

The examiners presiding over the permit application process for a Montana-based oil and gas waste company looking to build a facility in San Augustine recommended the Texas railroad commissioners deny the permit.

“Regarding the geologic and hydraulic site characterization offered by the application, the examiners find it inadequate and inconclusive to support that the proposed facility site is suitable for its intended purpose,” the examiners wrote in a notice to the parties involved.

PA Prospect Company of Montana submitted an application to the Texas Railroad Commission for a permit to construct an oil and gas waste facility in the headwaters of Sam Rayburn Reservoir in November 2019.

Jay Stewart, an attorney associated with Hance Scarbrough LLP, which is representing PA Prospect, was not available to respond to The Lufkin Daily News.

The proposed 256.7-acre facility is split by state Highway 103 with plans to construct waste receiving and treatment facilities on the northern tract while the southern tract would contain a waste receiving pad and an 11-cell landfill.

The Chinquapin Community surrounding the proposed facility has fought against the proposed facility out of concerns about what the facility could do to local surface and groundwater, especially considering how many residents rely on individual water wells.

Examiners concluded the application to-date is not complete and does not meet the requirements set forth in Statewide Rule 8, according to a notice sent on March 10 to all parties involved in the application process.

Statewide Rule 8(b) prohibits any person engaging in activities subject to regulation by the commissioner from causing or allowing the pollution of surface or subsurface water in the state.

“Being incomplete, the application does not adequately demonstrate the proposed facility will not result in the pollution of surface or subsurface water,” the notice states. “Therefore, the application has not met its burden for the issuance of a permit for the facility.”

According to the examiner, PA Prospect, over the course of the permitting process, submitted nearly 700 pages of text and diagrams to support the permit, the notice states. The original permit was considered administratively complete, but changes in the following months altered the permit enough to warrant a post-hearing conference to obtain a comprehensive review of the application.

“While there may be amendments to an application during the hearing process, the large number of proposed changes and the fact that there is much information still needed creates significant uncertainty,” the examiners wrote.

“Given the number of amendments, revision and then retractions of proceed facility design and operations, it appears that the application was reacting during the hearing process to application deficiencies revealed by protestants or examiners.”

Deficiencies in the work were noted by Geoffrey Reeder, a Texas A&M graduate with a master's degree in soil sciences and former remediation specialist for the Union Pacific Railroad, and his wife Ellen, a former petroleum geologist who worked as a regulator for the Louisiana Department of Environmental Quality.

“It’s no different than when you’re in school and you turn in your test to your teacher. You can’t walk back to your seat and say, ‘Oh, wait a minute, I thought of a better answer,’” Reeder said. “You can't do that once. They did it 100 times.”

Reeder submitted his complaints with the Texas Board of Professional Geoscientists about the geologist hired by PA Prospect. The geologist, Tracy O’Shay, is facing potential disciplinary actions as a result of her work on the application.

Reeder said he was glad the examiners did not recommend the permit for approval for a lot of reasons — most of which stemmed from the difference in rules from Louisiana to Texas.

“The rules in Texas that govern these types of facilities are much more lax than those in Louisiana,” he said. “And it’s kind of embarrassing to say that Louisiana is ahead of Texas in protecting the environment and human health — but they are.”

Additionally, the examiners noted the proposed site is surrounded by wetland features, riverines and seeps. PA Prospect only drilled two of the nine wells within the parameters of the landfill and avoided detection of the unconfined Yegua-Jackson Aquifer, according to the notice.

“As an example of the inadequacy of applicant’s geologic and hydraulic characterization, Protestant (Ann) Bridges measured the water elevation level in a shallow well approximately 250 feet from the facility site to be 278 feet above (mean sea level), putting the construction excavation depth of two landfill cells and the contact stormwater pond No. 2 potentially below the water table elevation,” the examiner wrote.

Bridges was concerned when she first saw the notice of the landfill because she didn’t believe anyone would monitor the facility. She was worried about its impact on the water in the community as well as the potential noise and smell of the facility.

“I feel like we’ve maybe won the first round, but it’s not over,” she said. “I know the commissioners vote on it next month.”

She did not want to say anything that might make the commissioners consider going against the recommendation of the examiners.

This notice of the examiner's opinion does not guarantee the permit will be denied.

The commission is currently facing backlash for its approval of a permit — despite the examiners' recommendation the permit be denied — to construct a nine-story-tall oilfield waste repository in West Texas, the Odessa American reported in early February.

If the commissioners agree to deny the permit, PA Prospect still has 25 days after the order denying the permit is signed to file for a rehearing, according to the notice. If the company files for a rehearing, the commission has 100 days from the date the order is signed to take action after a rehearing.

Jess Huff's email address is **jess.huff@lufkindailynews.com.**

Exhibit 7.04

This exhibit was not previously submitted in November 2023

Re: Proposed Amendments to Statewide Rules 8 and Subchapter B (August 2024)

Declaration of Geoffrey Reeder

1. My name is Geoffrey Reeder; I am over the age of 18 and am competent to make this declaration to the following facts based on my personal knowledge.
2. I am a supporter of Commission Shift. I subscribe to Commission Shift's newsletter, participate in Commission Shift events and calls to action, and support its mission, which is to reform oil and gas oversight by building public support to hold the Railroad Commission of Texas accountable to its mission in a shifting energy landscape. In particular, I concur with Commission Shift's concerns about the proposed rewrite to Statewide Rule 8 and Subchapter B.
3. I am a retired environmental professional. I obtained a masters degree in soil science from Texas A&M, and was a licensed soil scientist in both Texas and Louisiana. I worked for a large railroad company for decades: I did emergency response to chemical releases, then worked in environmental remediation. I managed projects in eleven states, including Texas, Louisiana, New Mexico, Oklahoma, Arkansas, Tennessee, Illinois, Michigan, Wisconsin, Minnesota, and Indiana.
4. My wife, Ellen Reeder, was a geologist for the Louisiana Department of Environmental Quality (LDEQ) and before that was a geologist for oil and gas companies.
5. My wife and I own approximately 50 acres of land at 1299 FM Road 3017, 75972 in San Augustine County, where we live approximately 50% of the time. Approximately half of the land is a tree farm and we lease out a portion of it as a pasture which is used for hay production.
6. While at our property we enjoy spending time outside in nature. We greatly value keeping the property a refuge for all creatures.
7. For example, we enjoy exploring the many trails on our property. Sometimes we explore by foot, other times we use our open-air golf cart or our open-air jeep. The county roads in San Augustine are not paved, except for possibly some small portions of these roads as they pass through town.
8. We also enjoy the wildlife that lives in our area. For example, my wife Ellen is an avid amateur naturalist, with hundreds of contributions to online naturalist forums documenting the insects, birds, amphibians, mammals, reptiles, and plants on and around our property.
9. There are several natural features on our property that we are particularly proud of. One is a stand of red bay trees. As visiting experts have explained to us,

these trees are not common to the area. The more we learn about them, the more interesting they get.

10. Another feature we enjoy on our property are the natural springs. These springs are on the west side of our property, approximately 2,000 feet from Farm Road 3017. It's a location where groundwater naturally bubbles to the surface. Academics from Huntsville and San Marcos have visited these springs and found small fish living in them, some of which they have collected for study in their labs.

11. The land has been in my family for generations---since the early 1900s---and I have made plans to leave it to my descendants. I have a grandson, and a great-grand daughter, who was born earlier this year. My children and their families visit our property every few months, typically at least three or four times a year. When they visit, they join us in enjoying the property by foot, golf cart, and jeep.

12. We have several water wells onsite: a 360-feet deep well that was installed around 2010 and is about 1,000 feet from the road; a shallower water well at approximately 180 feet installed in the 1970s that is about 100 feet from the road; and the oldest well is screened in a shallow unit approximately 20-25 feet below ground surface and is 60 feet from the road. My cousin, who lives on an adjacent property, also has a shallow well of similar depth that he uses.

13. Our land currently also has a horizontally drilled natural gas well on the east side of the property that taps into the Haynesville Shale; that well was installed and developed around 2010-2011. When I signed the lease of my mineral rights for that operation, I did not expect that a well would actually be drilled --- because for decades speculators had offered to lease our land, and nothing ever came of it. But this time was different. Although I would have wanted to have a say in how the waste was managed---e.g., how it was contained, whether it would stay onsite forever, how soil and groundwater would be protected---the lease I signed gave me no say in the matter and the Commission's rules did not provide the safeguards I would have expected. To my knowledge the drilling waste was left onsite in an unlined pit and no site-specific investigations were done to characterize potential risks to groundwater, nor were any groundwater monitoring wells installed.

14. Other neighboring properties have additional well pads; to my knowledge, two are drilled into the Haynesville, another into a shallower formation: the James Lime.

15. I have noticed that the way our well pad is built and configured there would be room for another well to be installed. Indeed, I have been approached with offers to conduct additional drilling on my property. However, I do not trust that the

current or proposed rules would ensure that I could adequately protect my property, surface water, groundwater, and the environment from the oil and gas waste that would be generated, so I have and will continue to refuse additional requests to use my land for oil & gas exploration & production unless the operations would (1) be protective of human and environmental health and (2) require explicit surface owner consent on how the waste is managed and whether it is disposed of onsite. In my opinion, if the Commission adopted standardized rules requiring such protections, all landowners would be protected and no one would be at a competitive disadvantage by having to try to negotiate for these protections in a non-standard lease.

16. I have several other bases for my skepticism in the Commission's ability to ensure oil and gas waste is managed properly, including from my own experience and that of my wife.

17. For one example, we have had significant firsthand experience with the deficiencies in the Railroad Commission's oil and gas regulations prior to this rulemaking. Several years ago, a commercial oil and gas waste management facility was proposed in San Augustine County approximately 15 miles down the road from us. My wife and I reviewed the applicant's proposal and found it very deficient in a number of ways, including its analysis for the potential of groundwater contamination. We were part of the local opposition to the project and collectively spent hundreds of hours and tens of thousands of dollars to show what should have been apparent all along --- that the project would not protect human and environmental health. The applicant was allowed to amend its application during the first three-week hearing a full one hundred times, greatly prolonging the case and driving up costs for the protestants. In the end, the project was denied, but only because the public had done the work that the applicant, Commission, and its rules failed to do, which included forcing the applicant to reckon with well-known principles of basic hydrogeology. The Commission's proposed rules do not remedy the many deficiencies I experienced in that process. And if another such ill-suited project was proposed in the vicinity of our property in the future, I worry that we would need to spend similar amounts of time and money again because the Commission's proposed rules are insufficient to protect the public and environment.

18. Another cause for concern stems from my work experience with the railroad and my wife's experience at LDEQ. My wife has seen how in many instances, the Louisiana Department of Natural Resources does a better job at protecting human and environmental health from oil and gas waste than Texas does. Through my work I became familiar with the Resource Recovery and

Conservation Act rules on hazardous waste, which would apply to oil and gas waste but for a legal loophole that lets them evade these regulations, even if they would otherwise be characteristically hazardous. This does not prevent oil and gas waste from being dangerous to public and environmental health, however. And I am concerned that the proposed rules do not come close to treating oil and gas waste as hazardous, as they should, nor do they properly consider potential risks to human and environmental health.

19. I am also concerned about the Commission’s proposal in Division 7 of Subchapter B that would allow the reuse of drill cuttings on lease roads, county roads, as concrete bulking agent, oil and gas waste disposal pit cover or capping material, treated aggregate, closure or backfill material, berm material, or construction fill.

20. I am particularly concerned that no risk assessments were conducted before this rule was proposed. I understand that drill cuttings --- especially from the horizontal portions of the bore --- can be contaminated with heavy metals, radioactivity, and volatiles and semi-volatile contaminants, both from natural sources and from introduced chemicals and drilling muds. The only way to know what is in such material is to test for it. For example, I am concerned that the rules do not require testing for radioactivity, and even if they did, I am concerned that the levels allowed are not health-based. I worry that the methods proposed in the rule to test for possible contaminants may not accurately represent the leaching conditions that the drill cuttings will be exposed to in the field. For example, we live in a wetter area of the state on average, with many creeks, shallow groundwater, and natural springs.

21. I’m also aware that San Augustine County is one of the poorest counties in the state, with few funds for road repairs. Our official 2024-2025 county budget was just approved in September 2024 and allocates less than $100,000 for road materials. I worry that if Division 7 is approved as is, counties like mine would be tempted to take cheap, insufficiently treated drill cuttings for use on the roads or in other applications without asking sufficient questions about the hazards contained within (radioactivity or otherwise), leaving the county potentially on the hook for remediation for years to come and county citizens exposed to human and environmental health risks. I understand that some applications for these cuttings could be as cover or cap material, or even construction fill, risking direct exposure to unsuspecting members of the public.

22. This is especially concerning given the fact that our family frequently travels over the county roads near my property. We are often in our open-air golf cart or open-air jeep leading to exposure to dust; basically none of the county roads in San

Augustine are paved. My wife and I often hike the many trails on our property, and we often are very close to the land surface as we look for wildlife and plants to document. There is surface water and shallow groundwater around our area, making it of particular concern whether the proper leaching tests have been required by rule. I would not want any water or soil on my property to become contaminated. I also would not want harm to come to the vegetation on site from such practices, both for its aesthetic value and for tree production. I would also be concerned for my property value in the event contamination occurred.

23. In addition, because the rules would not require adjacent landowner consent or even notice before drill cuttings could be used on the road or in other applications, I fear that I would not know if and when to take precautionary measures to avoid exposure to myself, my family, and the environment.

Geoffrey Reeder

Geoffrey Reeder

10/10/24

Date

Exhibit 9.01

This exhibit was not previously submitted in November 2023

Re: Proposed Amendments to Statewide Rules 8 and Subchapter B (August 2024)

Declaration of David Todd

1. My name is David Todd; I am over the aged of 18 and am competent to make this declaration to the following facts based on my personal knowledge.
2. I am a supporter of Commission Shift. I subscribe to Commission Shift's newsletters, participate in Commission Shift events and calls to action, and I support its mission, which is to reform oil and gas oversight by building public support to hold the Railroad Commission of Texas accountable to its mission in a shifting energy landscape. In particular, I concur with Commission Shift's concerns about the proposed rewrite to Statewide Rule 8 and Subchapter B.
3. Our family corporation, Wray-Todd Ranch, owns roughly 1150 acres at 1000 Grace Place Lane, Weimar Texas 78962 in Colorado County, which my wife, sister and I, as well as other family members, visit frequently. I am an officer of the corporation through which the property is managed. I consider both myself and the LLC to be supporters of Commission Shift.
4. Our property is used for cattle and hay production and is overseen by a foreman who lives and works onsite fulltime. The property is laced with gullies and a creek that drains into the Colorado River, which abuts the north side of the property. The hay is harvested for feeding cattle, including on three other properties that I own in the area.
5. Our property is only accessible by County Road 206, a stretch of unpaved gravel road that borders the property, which has been in my family since 1951 and to my knowledge has not yet been the site of drilling operations. Throughout the years there has been and continues to be interest in improving County Road 206, and potentially paving it. I am concerned that improperly treated drill cuttings could be used on this road if the Railroad Commission approves the Proposed Rulemaking. As a child, I remember growing up visiting my grandparents, who also had a gravel road leading toward their property. That road would be routinely sprayed with waste oil to suppress dust; a practice that is now known to spread harmful contaminants and threaten public and environmental health. I worry that much like that practice — which was once seen as benign and is now known as harmful — the practices proposed in Division 7 of Subchapter B will later come to be recognized as harmful, creating lasting harm to property, human health, and the environment.
6. I am particularly concerned that no risk assessments were conducted before this rule was proposed. I understand that drill cuttings — especially from the horizontal portions of the bore — can be contaminated with heavy metals, radioactivity, and volatiles and semi-volatile contaminants, both from natural sources and from introduced chemicals and drilling muds. I am concerned that the rules do not

require testing for radioactivity, and even if they did, I am concerned that the levels allowed in oil and gas waste are not health-based. I worry that the methods used to test for possible contaminants may not accurately represent the leaching conditions that the drill cuttings will be exposed to in the field. This is especially concerning given the creeks onsite, my proximity to the Colorado River and the fact that we have 5 groundwater wells on the property, which are used for domestic use and livestock. One well is within 800 feet of County Road 206.

7. In addition, because the rules would not require adjacent landowner consent or even notice before drill cuttings could be used on the road, I fear that I would not know if and when to take precautionary measures to avoid exposure to myself, my family, Wray-Todd Ranch staff, and the environment.
8. My wife and I, and my sister like to recreate on the property and I would worry about their exposure. We enjoy hiking, swimming, fishing and hunting. I worry that if drill cuttings are used on the country road, we could ingest dust containing contaminants, or that runoff from the road could make its way into the water, and then be ingested by cattle, wildlife, my family, or the staff who run the ranch. I am particularly concerned for the health and well-being of the foreman, who lives onsite and ranges across the property and back and forth along the county road tending to the cattle. I also do not want harm to come to the vegetation on site from such practices, both for its aesthetic value and for the harm it might do to hay production. I worry that my property values may decrease if it turns out that contaminated materials have been placed on the county road.
9. I, like many in Texans, have family ties to oil and gas and acknowledge its importance to the state. I recognize the need for practical oil and gas regulation, but I am emphatic that it must not be at the sacrifice of and threat to human and environmental health. By virtue of my family history, I well remember one of the important reasons why the Railroad Commission began—to help protect Texans from the waste of a burgeoning oil and gas industry. I strongly believe it is time for the Commission to take that mantle up again, to act with transparency and integrity, and to not approve the oil and gas waste rules as they've been proposed.

10/7/2024

David Todd

Date

Exhibit 14.03

This exhibit was not previously submitted in November 2023

Comments on Proposed Amendments to 16 TAC Chapter 4

Beneficial Use of Drill Cuttings

Submitted to:

Commission Shift

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October 9, 2024
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Downstream Strategies

Ideas that sustain.

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1. INTRODUCTION

I, Marc Glass of Downstream Strategies, LLC (DS) have prepared this report at the request of Commission Shift, regarding the Railroad Commission of Texas' ("the Railroad Commission") rulemaking regarding oil and gas waste management, disposal, and recycling; specifically, the proposed changes to 16 TAC §3.8 and §3.57, and 16 TAC Chapter 4 ("the Rulemaking").

My opinions presented herein are my own and based on the data and facts available to me at this time and my involvement in matters with management of wastes generated by oil and gas production and development in several states. Should additional information become available, I reserve the right to supplement the opinions expressed in my report.

1.1 Investigator background

I am a Principal and Senior Scientist at Downstream Strategies, LLC (DS), a Morgantown, West Virginia–based environmental consulting firm, at which I direct the environmental monitoring and remediation program. I am a West Virginia Department of Environmental (WVDEP) Protection Licensed Remediation Specialist (No. 175), with twenty-five years of direct experience in conducting environmental investigation, site characterization, and cleanup of environmental releases. I have been retained by numerous public and private clients where my expertise has been utilized for site assessment and data review and interpretation. I have managed numerous site investigation and cleanup projects dealing with heavy metals, petroleum hydrocarbons, dense non-aqueous phase liquids (DNAPLs), light non-aqueous phase liquids (LNAPLs), polychlorinated biphenyls (PCBs), various chlorinated solvents, and other hazardous substances. I have conducted research and authored reports pertaining to the monitoring and management of unconventional oil and gas NORM waste streams in solid waste landfills and led projects involving assessment and cleanup of NORM from oil and gas brine spills. From 2011 through 2017, I served as the court-appointed remediation technical expert for a class action settlement resulting from heavy metals contamination from a former zinc smelter in West Virginia, where exterior soil and interior dust remediation was performed over a 35–square mile area. I currently serve as the Technical Advisor to the Harvey-Crosby environmental remediation Settlement near Houston, Texas overseeing characterization and remediation of residential homes and soils impacted by dioxin particulate fallout. I have conducted research and authored reports pertaining to the monitoring and management of unconventional oil and gas waste streams in solid waste landfills. I have also provided testimony in federal court pertaining to environmental contaminants in wastes generated by unconventional oil and gas development in West Virginia and led or provided consultation regarding site assessment and cleanup of environmental release sites in Pennsylvania and West Virginia. My CV is included as Appendix A.

My opinions presented herein are my own and based on the data and facts available to me at this time and my involvement in matters, including legal cases, involving assessment and cleanup of environmental releases over large areas from commercial and industrial facilities. Should additional information become available, I reserve the right to supplement the opinions expressed in my report.

2. COMMENTS

In August 2024, the Railroad Commission (RRC) proposed new rules regarding the recycling of and beneficial use of drill cuttings (to be added as 16 TAC Chapter 4, Division 7) ("Proposed Rules"). These Proposed Rules prescribe procedures for turning drill cuttings into materials that could be used in many construction applications, including road base and fill. But as these comments explain, these rules are not based in science or fact and should not be adopted—they will fail to prevent pollution of the waters of the state and will endanger public health.

This is particularly concerning because the amendments would potentially alter the disposition of millions of tons of contaminated waste annually, from being buried in localized pits to being spread across the surface of the state. Most oil and gas development since 2000 is conducted using unconventional oil and gas development methods, characterized by the combination of horizontal drilling and hydraulic fracturing. The long well bores needed to achieve the vertical depth and horizontal exposure to target formations result in historically large volumes of cuttings from each well drilled.

These long horizontal well bores have resulted in historically unprecedented volumes of drill cuttings that require management. In its study evaluating potential options for management of drill cuttings (CEGAS, 2015) the West Virginia Department of Environmental Protection (WVDEP) estimated horizontal wells typically produced 1,500 tons (~5,500 yd^3) or more of drill cuttings per well. Last year, over 8000 new wells were drilled in Texas.[1] Assuming only 80% of these wells were horizontal,[2] this represents more than 9,600,000 tons of drill cuttings produced annually. And with the evolution toward longer horizontal bores and increased development of deeper shale formations, this figure is certainly an underestimate for contemporary wells that often generate over 2,000 tons of drill cuttings per well (Lopano, 2020). Horizontal bores also typically require drilling muds with additional contaminants of concern, especially as they pass through shale formations. Organic shales are commonly enriched with heavy metals (i.e. arsenic, barium, vanadium, and uranium) compared to other sedimentary rock (Leventhal, 1981, 1991), In addition, on average NORM levels are known to be higher in horizontal segments as opposed to vertical segments, increasing the risk from NORM beyond what the Commission has likely had to account for in past decades.

Coupled with the "shale gas revolution", the unprecedented quantity of drilling cuttings generated has created stress on existing systems and the need to identify environmentally responsible management options. Responsible development of shale gas resources is important to support economic development, improve energy security, and has the potential to provide environmental benefits by reversing the trend of increasing human and ecological exposure to oil and gas related contaminants released into surface and near environments.

Yet if finalized as proposed, these Amendments will fail to prevent pollution of the waters of the state and increase human exposure to contaminants in drill cuttings, as the following comments explain.

2.1 Recommendations

As proposed, the Amendments permitting beneficial use of drill cuttings will cause pollution and the alteration of the physical, chemical and biological quality of air, groundwater, surface water, soils,

[1] https://www.rrc.texas.gov/media/afbdzggf/july-2024.pdf
[2] "In 2021, 81% of U.S. well completions were horizontal or directional, as opposed to 19% of wells that were drilled vertically." https://www.eia.gov/todayinenergy/detail.php?id=52138

and sediments in Texas that is detrimental to public health, safety, welfare, ecological receptors and property, in violation of the Texas Water Code.[3]

As drafted, the Amendments will allow pollution of surface or subsurface water and run contrary to the prohibitions of such pollution in Texas Natural Resources Code, §91.101(a) (''the commission shall adopt and enforce rules and orders''. . . ''[t]o prevent pollution of surface water or subsurface water in the state''); Texas Water Code, §26.131 (RRC is ''solely responsible for the control and disposition of waste and the abatement and prevention of pollution of surface and subsurface water''). As drafted, the Proposed Rulemaking also lacks the necessary monitoring requirements to evaluate compliance with Texas Water Code, §26.131.

Adding new drill cutting contaminants as ingredients of beneficial use products into surface environments where they can be broken down and released over time requires consideration of future land use and long-term stability of the beneficial product. Natural weathering or physical agitation during road maintenance/utility work, or even future recycling of road-bed materials, warrants that environmental contaminants in beneficial use materials (drill cuttings) are kept very near the current natural background levels where they are placed to prevent a source for future contamination. Also, future land uses will undoubtedly change over time, years, decades or even much longer into the future, so contaminants embodied in beneficial materials must not be allowed to inhibit future unlimited and unrestricted land use.

In order to protect against pollution, the Commission must withdraw its Proposed Rulemaking. Any revised proposed rulemaking on this topic would need to:

1. Require that all treated batches are tested for the parameters listed in both 16 TAC §4.302(c)(1)- "Parameters and Limitations for Roadbase," and 16 TAC §4.302(c)(2) – "Parameters And Limitations For Reusable Product,". The Rulemaking provides no basis for why one beneficial use warrants different testing parameters and limits than another use, so a single list for all beneficial use batches should be used. See Section 3.

2. Add analysis for all of the NORM isotopes from the Uranium-238 and Thorium-232 decay chains to 16 TAC §4.302(c)(1) and 16 TAC §4.302(c)(2). See Section 4.

3. Amend the Rulemaking to have NORM limits for beneficial use drill cuttings that do not exceed 5 pCi/g above the local background surface soil conditions for combined Radium 226 and Radium 228 where any beneficial use drill cutting product is to be used. See Section 4.

4. Test radionuclide activities using SW-846 Method 901.1M, consistent with the Ohio Department of Health (ODH,2019) NORM testing protocol, utilizing a high-purity Germanium detection and minimum 28-day ingrowth period. To determine the stability of radionuclides and the potential for NORM from drill cuttings to leach from where drill cuttings for beneficial use are placed, additional testing and analysis is also likely warranted. Beyond the gamma emitting radionuclides likely to be present in drill cuttings, assessment of the human health risks associated with drill cuttings should include isotopic analysis of all environmentally persistent radionuclides including pure alpha emitters (Uranium 234, Thorium 230, and Polonium 210) as well as the low-level ß emitter (210Pb). (Eitrheim et al, 2016). See Section 4 and 6.

[3] Tex. Water Code 26.001 (14) "Pollution" means the alteration of the physical, thermal, chemical, or biological quality of, or the contamination of, any water in the state that renders the water harmful, detrimental, or injurious to humans, animal life, vegetation, or property or to public health, safety, or welfare, or impairs the usefulness or the public enjoyment of the water for any lawful or reasonable purpose.

5. Require that the LEAF framework, TCLP (1311) and SPLP (1312) methods are used to evaluate Radium 226 and all other potentially soluble radionuclides from the Uranium and Thorium decay chains prior to public or private release of drill cuttings for beneficial reuse to confirm that the new treated product is not a hazardous waste (16 TAC §4.208(a)(2)). It is noted that these leaching tests are meant to simulate the conditions of leaching potential of waste placed in a landfill setting or exposed to intense weathering processes. However, these tests do not necessarily represent additional forces that can expedite and exacerbate the leaching process, such as chemical forces, like brine, fuel, solvent, or other chemical spills, or mechanical forces such as grinding, sawing, cutting, abrading, milling, crushing, etc.. that are applicable to the beneficial uses contemplated by the Rulemaking. Therefore it is essential that applicants be required to test the materials under the conditions expected for each beneficial use. See Section 4 and 5.

6. Amend the Rulemaking to account for emanation of Radon 222 from material in beneficial reuse placements. The Commission has not addressed the emanation of Radon gas, or the human exposure to its radioactive decay products, from treated drill cuttings that are permitted for reuse. Since according to (definition of NORM 16 TAC §4.208(a)(3)) there may be up to 30 pCi/g of either or BOTH Radon 226 and Radon 228, both of which include Radon 222 (Radon gas) in their radioactive decay chains, emanation of Radon 222 will occur. Once released to the atmosphere in gaseous form, Radon 222 will migrate as any gas in the environment and continue its radioactive decay. See Section 4.

7. Expand the testing requirements in 16 TAC §4.302(c)(1) and 16 TAC §4.302(c)(2) to include additional parameters to include the target analyte lists for semi-volatile organic compounds by M8270, low level polycyclic aromatic compounds (PAHs) by M8270 SIM, the full target analyte list including the 22 heavy metals rather than the truncated lists 16 TAC §4.302(c)(1) and 16 TAC §4.302(c)(2) so that contaminant concentrations in beneficial use materials that contain drill cuttings can be evaluated against human and ecological-health based screening levels. See Section 5.

8. Assessment of drill cutting suitability for use in beneficial products should be conducted in accordance with human and ecological health risk-based methods and criteria and not solely hazardous waste disposal criteria. Revise the limitations provided in Figure 1 and Figure 2 for chemical parameters to align with Texas human and ecological health-based standards, such as the Texas Commission on Environmental Quality (TCEQ), Texas Risk Reduction Program (TRRP), Tier 1 Protective Concentration Levels (PCLs) and Human Health and Aquatic Life Surface Water Risk Based Exposure Levels (RBELSs). See Section 5.

9. Amend the Rulemaking to ensure that financial assurance is available if material in beneficial reuse is released to the environment and requires a response or corrective actions. See Section 5.

10. Conduct a risk assessment that considers plausible current and future exposure to all contaminants reasonably contained in treated drill cuttings. See Section 8.

The following sections discuss some of the environmental factors affecting the beneficial use of drill cuttings and present information in support of the recommendations provided herein.

3. THE TESTING PROPOSED OMITS CONTAMINANTS OF CONCERN AND IS INADEQUATE

To comply with statutory requirement of Tex. Nat. Res. Code § 123.0015 (c)that the applicant must demonstrate that the product "is at least as protective of public health, public safety, and the environment as the use of an equivalent product made without treated drill cuttings.", it is necessary that the applicant be required to perform chemical analyses for all known and reasonably known potential contaminants that may be present in drill cuttings to make such comparison. Exemption of such material to undergo such testing is contrary to basic science and ensures that reasonably anticipated contaminants will be passed into materials that have a reasonable likelihood of creating unacceptable exposures to the public and other environmental receptors.

In proposed 16 TAC§4.301, the Commission identifies different testing parameters based on intended beneficial end uses:

1. construction of oil and gas lease pads or oil and gas lease roads, construction of county roads
2. used as a concrete bulking agent, oil and gas waste disposal pit cover or capping material, treated aggregate, closure or backfill material, berm material, or other construction fill

A summary of the Rulemaking testing requirements and sampling strategies for drill cuttings considered for beneficial reuse is provided in Figure 1 and Figure 2, below.

Figure 1: Testing and sampling requirements for drill cuttings

Intended Use	16 TAC ref.	Required environmental testing parameters	Required frequency	Criteria
Facility Permit for: treatment and recycling for beneficial use of drill cuttings	§4.302 (b) Figure: 16 TAC §4.302(c)(1) Figure: 16 TAC §4.302(c)(2)	Figure 1: Parameters And Limitations for Roadbase And Figure 2: Parameters And Limitations for Reusable Product	Trial run, only the first 1,000 cubic yards 4 samples per 200 cubic yards (10 samples)	Figure 1 Limits Figure 2 Limits
Each batch "as needed"	§4.302 (c)(1)(A)	"Bench scale tests"	As needed - if changed from trial run	None
For use in construction of: oil and gas lease pads or roads county roads	§4.302 (c)(1)(B) §4.302 (c)(1)(C)	Figure: 16 TAC §4.302(c)(1) Figure 1: Parameters And Limitations for Roadbase	After treatment Every 800 cubic yards after trial 4 samples per 200 cubic yards (8 samples)	Figure 1 Limits Re-treat and re-test until pass, or dispose
For use as: concrete bulking agent, oil and gas waste disposal pit cover or capping material, treated aggregate, closure or backfill material, berm material, or other construction fill	§4.302 (c)(2)(B) §4.302 (c)(2)(C)	Figure: 16 TAC §4.302(c)(2) Figure 2: Parameters And Limitations for Reusable Product	After treatment Every 800 cubic yards after trial 4 samples per 200 cubic yards (8 samples)	Figure 2 Limits Re-treat and re-test until pass, or dispose

Figure 2: Parameters in 16 TAC §4.302(c)(1) and 16 TAC §4.302(c)(2)

Figure: 16 TAC §4.302(c)(1)

FIGURE 1: PARAMETERS AND LIMITATIONS FOR ROADBASE

PARAMETER	**LIMITATION**
Minimum Compressive Strength by *ASTM D 698, ASTM D 1557,* or *TxDOT Methods Tex-113-E, Tex-120-E, Tex-121-E, Tex-117-E* or equivalent	35 psi
Synthetic Precipitation Leaching Procedure (SPLP) *EPA Method 1312* Metals	
EPA Method 6010, 6020, or *7471A*	
Arsenic	≤ 5.00 mg/L
Barium	≤ 100.0 mg/L
Cadmium	≤ 1.00 mg/L
Chromium	≤ 5.00 mg/L
Lead	≤ 5.00 mg/L
Mercury	≤ 0.20 mg/L
Selenium	≤ 1.00 mg/L
Silver	≤ 5.00 mg/L
Zinc	≤ 5.00 mg/L
Benzene	≤ 0.50 mg/L
EPA Method 1312, 8021, or *8260B*	
Leachate Test[1]	
Total Chlorides	≤ 700 mg/L
Total Petroleum Hydrocarbons (TPH)	≤ 100 mg/L
pH	6-12.49 s.u.

Figure: 16 TAC §4.302(c)(2)

FIGURE 2: PARAMETERS AND LIMITATIONS FOR REUSABLE PRODUCT

PARAMETER	**LIMITATION**
Moisture Content	<50% (by weight) or zero free moisture
ASTM D2216 or equivalent	
pH [2]	6.5 - 9 s.u.
EPA Method 9045 or equivalent	
Chlorides	≤ 3,000 mg/kg
Sodium Adsorption Ratio (SAR) 2	≤ 12
Exchangeable Sodium Percentage (ESP) 2	≤ 15
Total Barium 2	≤ 100,000 ppm
LDNR Leachate Test Method, 1:4 Solid:Solution [3]	
TPH [2]	≤ 10.0 mg/L
Chlorides [2]	≤ 500 mg/L
Leachable Metals 2	
EPA Method SW-846, 6010, 6020, 7000, 7470, or *7471*	
Arsenic	≤ 0.5 mg/L
Barium	≤ 10.0 mg/L
Cadmium	≤ 0.1 mg/L
Chromium	≤ 0.5 mg/L
Copper	≤ 0.5 mg/L
Lead	≤ 0.5 mg/L
Mercury	≤ 0.02 mg/L
Molybdenum	≤ 0.5 mg/L
Nickel	≤ 0.5 mg/L
Selenium	≤ 0.1 mg/L
Silver	≤ 0.5 mg/L
Zinc	≤ 5.0 mg/L
TCLP Benzene	≤ 0.50 mg/L
EPA Method SW-846/1311/8021/8260B	

Source: Adapted from Proposed Figure 1 and Figure 2, the Rulemaking.

As recognized by the Commission in the Proposed Rulemaking, it is appropriate to have testing performed for each batch prior to release of any product for beneficial reuse.

However, the lack of testing parameters for contaminants known to be associated with oil and gas waste leaves no assurance that products designated for beneficial reuse can comply with the statutes identified in Section 2 and:

1. Tex. Nat. Res. Code § 123.0015 (c) - the product "is at least as protective of public health, public safety, and the environment as the use of an equivalent product made without treated drill cuttings."

2. 16 TAC § 4.208(b)(1) - "will not result in the pollution of surface or subsurface water, a threat to public health and safety."

3. 16 TAC § 4.208 (a)(3)- is not NORM.

For example, no testing is required for PFAS, or the full suite of potential contaminants like metals, semivolatiles, bromides, and more. And as the above figures show, there is zero requirement in the Rulemaking for laboratory analysis of the NORM activity present in the materials.

The following section discusses these concerns in greater detail: NORM is discussed in Section 4 and other constituents of concern in Section 5. A comparison to other states is made in Section 6.

4. NORM IS AN OVERLOOKED CONTAMINANT OF CONCERN

If treated drill cuttings that contain NORM levels allowed by the Rulemaking are allowed into the environment under the exposure scenarios listed in the Rulemaking, they will cause alteration of the chemical or biological quality of air, groundwater, surface water, soils, and sediments in Texas that is detrimental to the health of human and ecological receptors in violation of the Texas Water Code and Texas Natural Resources Code. Because NORM testing is completely missing from this Proposed Rulemaking, I address NORM concerns first, in the sections below.

4.1 NORM in Texas drill cuttings

Across the U.S. and specifically in Texas, many geologic formations rich in oil and gas resources are well documented to contain naturally occurring radioactive material (NORM), primarily from the Uranium-238 and Throium-232 radioactive decay chains (Costa et al, 2023; Gray, 1993; PADEP, 2016; USGS, 2019; Nowak et al, 2020).

Like other shale gas producing formations such as the Bakken and Marcellus, shale from the Permian Basin of central and western Texas contains high radioactivity compared to soils and other environmental media normally encountered by the public in surface environments. (For context, total Radium activities in most natural rocks and soils are generally between 0.5 and 5 pCi/g (USGS, 1999)). These elevated levels are of radiological significance and represent a major source of Radium added into the environment (Takur et al, 2022). While other significant Texas shale plays such as the Eagle Ford formation are reported to have comparatively lower levels of NORM, that does not negate concerns, since the drill cuttings contemplated by this Proposed Rulemaking could come from any formation in Texas --- or beyond.

As for Texas-specific levels of expected radioactivity in either background soils or drill cuttings, I understand that the Commission's Proposed Rulemaking does not cite or rely on any scientific studies or otherwise to establish the expected levels of radioactivity in this media, neither as part of the published Proposed Rule nor in response to Public Information Act Requests. The only data cited by the Commission as to establishing background concentrations of radium and thorium decay chain compounds (including but not limited to radium 226 and radium 228) was results of field studies of NORM in equipment conducted from December 1999 to mid-March 2000.[4] According to the Commission:

> "More than 5,900 readings were collected on more than 600 leases and other oil and gas facilities...Of the 612 sites surveyed, ...59 sites had equipment with readings above 50 μR/hr, the limit above which the equipment cannot be released for unrestricted use. Out of over 5,900 readings, ...203 readings were above 50 μR/hr. The survey, however, indicates that specific geographic areas tend to have elevated NORM levels."

Only two districts had no readings greater than 50 μR/hr: RRC Districts 1 and 8A. Meanwhile radioactivity levels in equipment reached as high as 1100 μR/hr at a site in District 8.

While these levels reflect radioactivity in equipment, and not drill cuttings or background soils, they illustrate the risks of radioactivity from oil and gas wastes in general and how radioactivity levels can accumulate. In addition, this data was collected prior to the shale gas revolution, at a time when most wells were vertical and did not include the long horizontal segments typical of exploration and production today that are well known to have higher radioactivity levels than vertical segments. I

[4] https://www.rrc.texas.gov/oil-and-gas/applications-and-permits/environmental-permit-types/norm-waste/norm-field-measurements/

would thus expect the radioactivity levels to be higher—i.e., more concerning—than this 1999-2000 data would predict.

Lacking data to clearly justify use of a different value, the Commission should presume soil background for combined Radium 226 and Radium 228 to be 2pCi/g, as the default value used by other significant gas producing states such as Ohio (See Section 6.3).

4.2 NORM prohibition vs. exemption

Regardless of expected levels of radioactivity, 16 TAC §4.603 prohibits NORM in the beneficial use of drill cuttings. However, the definition of NORM would still permit radioactive material in beneficial use materials at many times background levels.

16 TAC §4.603 refers to the definition of NORM provided in 25 TAC §289.259(d), which exempts oil and gas NORM waste if:

1. Activity levels are 30 pCi/g or less for Radium 226 or Radium 228 in the upper 15cm of soil, or other media.
2. Activity levels of 150 pCi/g or less for any other NORM in the upper 15 cm of soil, or other media

In other words, the Proposed Rulemaking would allow drill cuttings permitted for beneficial use to include significant activities of Radium 226 or Radium 228: up to 30 pCi/g, or 150 pCi/g for any other radionuclide (even after treatment to reduce radioactivity). **These are much higher levels of radioactivity than present in most natural rocks and soils where total Radium activities are generally between 0.5 and 5 pCi/g (USGS, 1999) and will cause alteration of the chemical and biological quality of air, groundwater, surface water, soils, and sediments in Texas that is detrimental to the health of human and ecological receptors in violation of 16 TAC §3.8(b).**

As will be discussed in forthcoming sections, these are significantly higher NORM activity levels than allowed by other major oil and gas producing states such as Ohio and West Virginia for disposal or beneficial use consideration.

4.3 Background on NORM and its presence in drill cuttings

A NORM of particular interest is Radium 226 due to its relative abundance in oil and gas waste streams, in part since it is generated by both the Uranium and Thorium decay chains, but also due to its solubility and environmental mobility. Radium 228 is another isotope commonly associated with oil and gas waste.

Drill cuttings may contain Radium 226, Radium 228, and other radioactive isotopes at activity levels many times that of surface soils. This is especially true for drill cuttings generated from horizontal or lateral portions of the well bore.

The oil and gas production process, whether conventional or unconventional, has and continues to generate historic quantities of TENORM in solid, liquid, and gas phases by bringing NORM that was once mostly sequestered in deep geologic formations into the surface environments occupied by humans. Over time, this consistent addition of TENORM contributes to and increases the “ambient background” concentration of NORM.

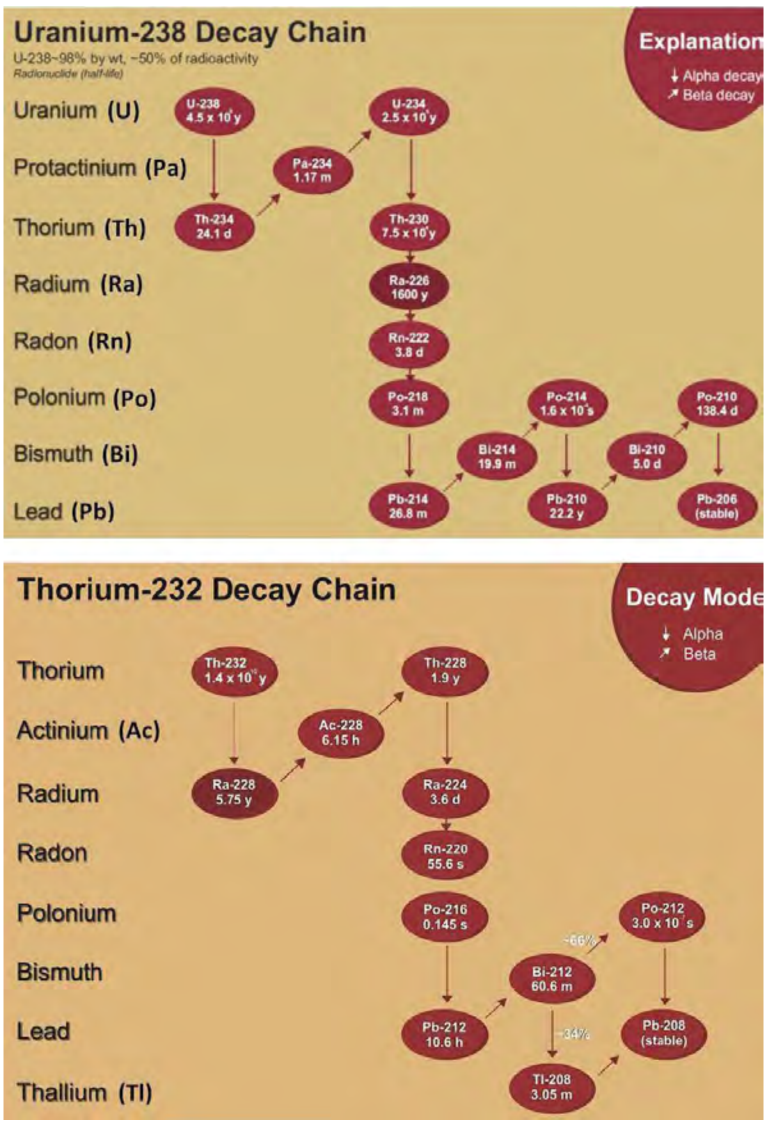
From NORM containing geologic formations, mixtures of gas, liquids, and solids, that are brought to the surface by oil and gas development contain radium, radon, and other radium radioactive decay products (NORM). As NORM is concentrated through the handling processes, it is often described as technologically enhanced naturally occurring radioactive material (TENORM).

This TENORM can be found in solids, liquids, sludges, and gases generated by oil and gas production wastes, and will generate Radon gas (Radon 222) through the constant radioactive decay of Radium wherever it is present. This includes flowback water, water produced from the geologic formation or "produced water", scale that builds up on the interior of pipes and containers, and drill cuttings that contain NORM.

TENORM from oil and gas wastes of primary environmental concern consists of Radium 226, Radium-228, and Radon-222 (gas). As part of the Uranium and Thorium radioactive decay chains, isotopes of Radium are generated. As Radium radioactively decays, Radon gas is created. Radon gas continues to undergo radioactive day into other isotopes, many of which are also radioactive.

As shown Figure 3 in each elemental isotope from the Uranium and Thorium decay chains radioactively decays to form a new isotope (daughter or progeny), which itself will undergo further radioactive decay until a stable isotope is reached.

Figure 3: Uranium and Thorium radioactive decay chains



Notes: y = years, d= days, h = hours, and m = minutes
Source: Adapted from PADEP, 2016

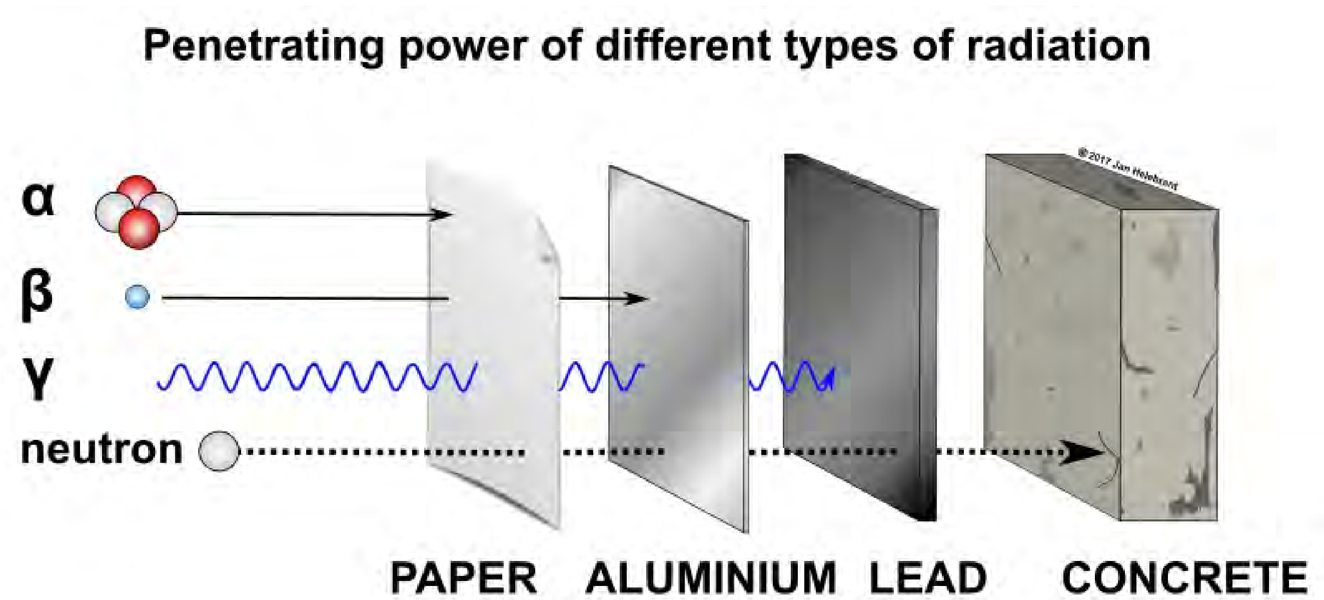
Both the Uranium-238 and Throium-232 decay series include Radium and Radon isotopes and their respective decay progeny, or daughters. As noted by the Pennsylvania Department of Environmental Protection (PADEP, 2016): “*Radon and its progeny are the primary issue of concern associated with natural gas distribution and its end uses*.”.

As each isotope from the Uranium-238 and Throium-232 decays to form a new daughter isotope, an alpha (α) or beta (ß) particle, or (Y) gamma ray is energetically emitted. The primary form of emission (alpha or beta) from each step in the Uranium-238 and Throium-232 decay chains is also shown on Figure 3.

Alpha and beta emission are particles ejected from the isotope during decay, whereas gamma emissions are electromagnetic waves. Each of these are ionizing forms of radiation, having the ability to cause damage to cells, chromosomes, and organs.

The relative penetrating power for each of the primary types of ionizing radiation is graphically represented in Figure 4. This penetrating power has a direct effect on the way ionizing radiation can cause tissue damage and how it can be detected by instruments or analytical methods.

Figure 4: Primary types of ionizing radiation



Source: OSHA, 2024

Unlike gamma radiation, which is electromagnetic energy, alpha and beta emissions are particles that can be stopped or shielded with thin layers of material. Alpha particles do not travel far in air and are easily stopped by a few sheets of paper, a thin layer of water, or the outer layers of skin. Gamma rays, which are pure energy, can penetrate deeply into substances. Several inches of lead are often required to stop gamma rays.

Even though alpha particles and most beta particles can be shielded by skin, exposure through ingestion or inhalation is hazardous. If alpha emitting radionuclides enter the body by these pathways, they are the most destructive form of ionizing radiation. It is estimated that chromosome damage from alpha particles is anywhere from 15 to 20 times greater than that caused by an equivalent amount of gamma or beta radiation (Brooks, 1975).

4.3.1 Radon daughters

When Radon or its daughters are inhaled, they impart the ionizing energy of their respective alpha or beta emissions (shown in Figure 4) directly to internal organs or lung tissue and damage chromosomes (ATSDR, 2012). It is for this reason that alpha particles can be very harmful to living cells when inhaled, ingested, or absorbed into the blood stream (e.g. through a cut in or area of non-intact skin). Similarly, while beta particles can penetrate the skin, they are most when inhaled or ingested.

Radon emissions from oil and gas drill cuttings and associated storage equipment are only a portion of the story in terms of radioactive health exposure. In fact, it is the decay of Radon into other elements (Radon daughters) that create the more significant dose to human tissue, particularly when inhaled (NRC, 1988).

Radon is a naturally occurring colorless, odorless, tasteless radioactive gas (ATSDR, 2012). Radon is a noble gas that does not react with other elements and is the densest of all gases. Radon will tend to settle to lower elevations faster than other gases. Radon is only degraded in the environment through radioactive decay into other radioactive elements, or daughters. Therefore, in a closed environment, Radon concentration will decrease with time in accordance with its radioactive half-life, and the concentration of its daughters will increase. It follows that Radon concentrations at short travel times from the original source will be higher than at longer travel times.

Even though radon has a half-life of 3.82 days (Figure 5), there are two key points to consider:

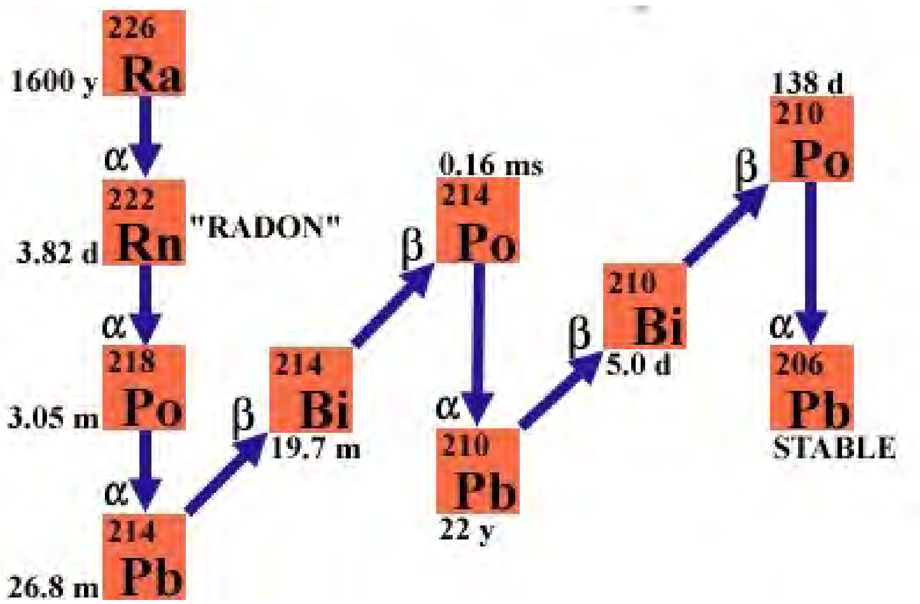
1. Each atom of radon that decays emits ionizing radiation into the local atmosphere and converts into other radioactive progeny with their own ionizing radiation emission.

2. If the source for Radon emissions remains constant, then it's half-life is not relevant to decreasing concentration trends for Radon as it will be replenished, but it is relevant to increasing concentrations of Radon radioactive progeny which will also be replenished.

Radon is a gas, but its radioactive products are not. As it decays Radon coverts by releasing ionizing particulate radiation to create radioactive polonium and lead that are microscopic solid particles. Radon and other radionuclides are classified under the CAA as Hazardous Air Pollutants.

The radioactive daughters of Radon (Rn-222), respective half-lives, and radioactive alpha and beta particle emissions are show below in Figure 5.

Figure 5: Radium-226 Decay Chain



Source: U.S Geological Survey

Half-lives for some shorter-lived Radon daughters are measured in mili-seconds, minutes, or several days, whereas the half-lives for longer-lived daughters, Lead-210 and Polonium-210 last for 22-years and 128-days, respectively. As each radioactive isotope decays into a new daughter isotope, an alpha (α) or beta (ß) particle is energetically emitted.

4.3.2 Airborne Radioactive Particulate Matter

Radon and its daughters are present in nearly all air, indoors and outdoors, but the addition of Radium and Radon from drill cuttings is additive to these existing background levels. Radon constantly radioactively decays until it has been completely converted to daughter products, which also continue to radioactively decay until a stable isotope of lead is reached.

Radioactive decay products of Radon (Radon-222) are solid particles that attach to other particles in the air and can be transported in the atmosphere (ATSDR, 2012).

Since Radon progeny are often attached to dust, risk from exposure to radon and daughters is exacerbated in the presence of particulate matter (ATSDR, 2012). Depending on the size of the particles, the radioactive particulates can deposit in lungs and impart a radiation dose to the lung tissue. Human exposure to Radon and its progeny is primarily through breathing, but also through ingestion and other pathways.

As discussed by Li et al (Li et al, 2020), Radon released into the atmosphere first decays into a chain of short-lived progeny that react with water molecules and atmospheric gases present to form ultrafine clusters. These clusters then attach to airborne particles, or PM. The short-lived progeny attached to the PM then decay into two long-lived progeny, Lead-210 and Polonium-210, which respectively account for most of the beta- and alpha-radiation then emitted from the resulting PM.

4.3.3 Because of these concerns the following recommendations are made

NORM from the Uranium-238 and Throium-232 decay series contained in drill cuttings will continuously undergo radioactive decay and produce and release Radon gas.

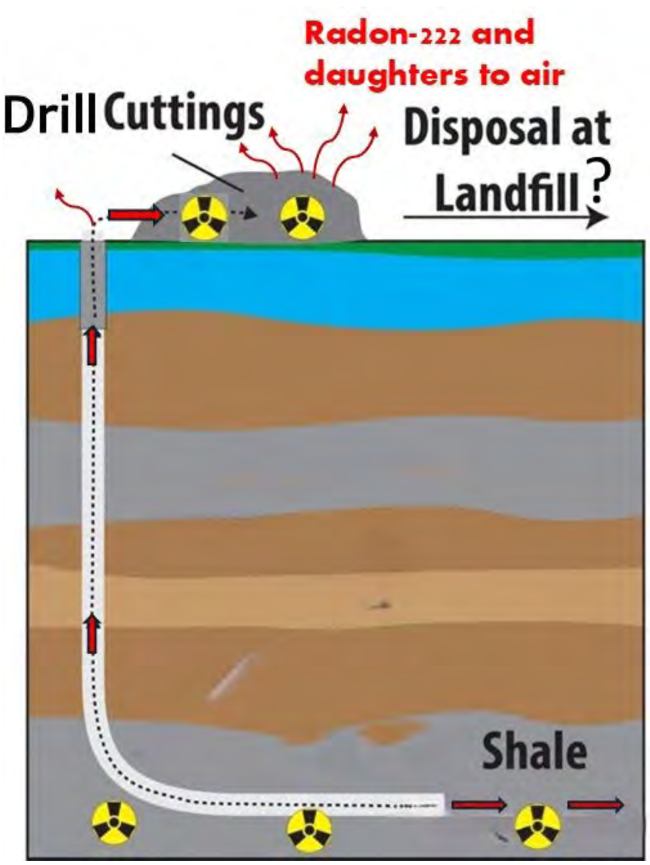
While there is already a background concentration of Radon from these same NORM isotopes present at low concentrations in near surface rocks and soils, NORM from drill cuttings that were previously mostly geologically isolated from human receptors add to this background, even if below the Rulemaking's exempt quantities of 30 pCi/g or less for Radium 226 or Radium 228 or 150pCi/g for any other radionuclide (16 TAC §4.603).

In fact, in the U.S. surface background for combined Radium 226 and Radium 228 generally ranges between 0.5 pCi/g and 5 pCi/g (USGS, 1999). The Rulemaking would allow up to an astounding 600% above these natural background levels.

When NORM is present in beneficial use materials (See 4.301(b)) for construction of oil and gas lease pads or oil and gas lease roads, or county roads; or used as a concrete bulking agent, oil and gas waste disposal pit cover or capping material, treated aggregate, closure or backfill material, berm material, or other construction fill, Radon gas (Radon-222) and it's radioactive daughter will also be emanated to the air and reach human receptors as well as be transported great distances.

Figure 6 illustrates Radon emanation from staged drill cuttings, but this illustration is also applicable to Radon emanation potential from any of the above-listed beneficial uses if NORM is present up to the exempt activities of 16 TAC §4.603

Figure 6: Radon 222 emanation from NORM in drill cuttings



Source: Adapted from Eitrheim et al, 2016.

To limit additional human exposure to Radon and its radioactive daughters from NORM in drill cuttings in beneficial use applications, the Commission should:

- Add all of the Uranium-238 and Thorium-232 decay series isotope analysis to 16 TAC §4.302(c)(1) and 16 TAC §4.302(c)(2) with limits that do not exceed the local background surface soil conditions where any beneficial use drill cutting is to be used. Unless a background value is established where the beneficial material is to be placed or used, then the Commission should presume it to be 5 pCi/g or less for combined Radium 226 and Radium 228. Allowing combined Radium activity levels greater than this, such as the 30 pCi/g exemption criteria in the Rulemaking, then the beneficial material will be a significant additional source for Radium and Radon contamination to the environment of Texas.

- Test radionuclide activities using SW-846 Method 901.1M, consistent with the Ohio Department of Health (ODH,2019) NORM testing protocol, utilizing a high-purity Germanium detection and minimum 28-day ingrowth period. To determine the stability of radionuclides and the potential for NORM from drill cuttings to leach from where drill cuttings for beneficial use are placed, additional testing and analysis is also likely warranted. Beyond the gamma emitting radionuclides likely to be present in drill cuttings, assessment of the human health risks associated with drill cuttings should include isotopic analysis of all environmentally persistent radionuclides including pure alpha emitters (Uranium 234, Thorium 230, and Polonium 210) as well as the low-level ß emitter (210Pb). (Eitrheim et al, 2016).

- Amend the Rulemaking to account for emanation of Radon 222 from beneficial reuse of drill cutting placements in the human environment. The Commission has not addressed the emanation of Radon gas, or the human exposure to Radon radioactive decay products from treated drill cuttings that are ingredients of products are permitted for reuse. The Commission should conduct radiological dose assessment modeling using RESRAD or other appropriate models to inform its Rulemaking with regard to human exposure from Radon emanation from beneficial use products. Since according to (definition of NORM 16 TAC §4.208(a)(3)) there may be up to 30 pCi/g of either or BOTH Radon 226 and Radon 228, emanation of Radon 222 from beneficial use products is more likely than not to occur. Once released to the atmosphere in gaseous form, Radon 222 will migrate as any gas in the environment into which is released and continue its radioactive decay into other radioactive and respirable particles.

5. ADDITIONAL DRILL CUTTING CONTAMINANTS ARE MISSING FROM THE PROPOSED RULE

Figure 16 TAC §4.243 does not include many parameters of environmental concern expected to be in drill cuttings such as: chloride, bromide, additional heavy metals, additional VOCs, additional SVOCs including polycyclic aromatic hydrocarbons (PAHs), and any combination of radionuclides from the Uranium 238 and Thorium 232 decay chains (Costa et al, 2023; Kazamis and Zorpas, 2021; Nowak et al, 2020; Gray, 1993; USGS, 2019; PADEP, 2016). To prevent pollution, the Commission must require these parameters be analyzed in the final treated “beneficial-use” products prior to release.

With a lack of these additional testing parameters, there is no assurance that these parameters/contaminants are not present in beneficial use end products and could potentially be released into the environment and create human and ecological exposures. The Commission must add (1) monitoring requirements as per Figure: 16 TAC §4.259(d) plus radionuclides at the site or property where beneficial use products are used (i.e. along roadbeds); and (2) financial security provisions of 16 TAC §4.25987(b) to cover potential response costs in the event that environmental release of beneficial use products occurs in the future. Lack of financial assurance mechanisms shifts the burden for any future cleanup costs to the landowner or state, an insurmountable burden clearly exemplified by the current problems caused by unplugged orphan and abandoned oil and gas wells and underfunded mining reclamation costs.

Indeed, Figure 7, which reproduces the parameters that must be monitored in groundwater at Texas fluid recycling and processing facilities, illustrates the Commission's recognition of some of the other parameters/contaminants associated with drill cuttings including soluble ion bromide, chlorides, and sulfate as well as additional metals including potassium and sodium . To not include sampling and analysis of these drill-cutting related parameters as part of assessment for drill-cutting recycling misses contaminants that may be released into the environment as beneficial use products break down over time.

Figure 7: Rulemaking parameters for groundwater monitoring at treatment and recycling facilities

FIGURE 1: PARAMETERS AND UNITS FOR GROUNDWATER MONITORING	
PARAMETER	**UNITS**
Static Water Level	Feet (ft)
Total Depth	ft
pH EPA Method 150.1, 150.2, or equivalent	s.u
Total Dissolved Solids (TDS) EPA Method 2540C or equivalent	mg/L
Total Petroleum Hydrocarbon (TPH) Method TX1005	mg/L
Benzene EPA Method 602 or equivalent	mg/L
Soluble Cations: Calcium, Magnesium, Potassium, and Sodium EPA Method 6010/6020 or equivalent	mg/L
Soluble Anions: Bromides, Carbonates, Chlorides, Nitrates, and Sulfates EPA Method 300/9056 or equivalent	mg/L

Source: 16 from TAC §4.291(a)(6)

The Rulemaking parameter list for required groundwater monitoring at drill cutting treatment and recycling facilities includes several leachable parameters (ie. bromides, nitrates, and sulfates) that are not included in the Rulemaking's required testing of drill cuttings for beneficial reuse that would provide useful indicators of the leachability

Other contaminants of concern in drill cuttings include, semi-volatile organic compounds (SVOCs), polycyclic aromatic compounds (PAHs), and additional heavy metals from the full target analyte list for Method 6010 (22 heavy metals) that are not included in the Rulemaking. It even lacks testing for many of the metals that TxDOT recommends be analyzed before recycled materials be used in construction, as part of TxDOT's DMS-11000 (Table 1).

As noted below in Figure 8 , West Virginia (33CSR1, Appendix V) provides a listing of contaminants the WVDEP considers of concern for drill cuttings and associated drilling wastes that it requires for leachate monitoring at all landfills that accept drilling waste. While it is important to note that this list still lacks some of the COCs that may be present in drill cuttings and should be tested for, it is more representative of leachable COCs that could be present in drill cuttings, even after undergoing treatment or recycling processing.

Figure 8: West Virginia leachate monitoring parameters for facilities that accept drilling wastes

Drilling waste contaminants		
Total suspended solids	Ammonia nitrogen	Radium 228
Chloride	Nitrogen nitrate	Strontium
Aluminum	Nitrogen nitrite	Strontium 90
Arsenic	Fluoride	Lithium
Cadmium	Benzene	Total nitrated hydrocarbons
Copper	Phthalate esters	Fluoranthene
Cyanide	Barium	Bis(2-ethylhexyl) phthalate
Hexavalent chromium	Antimony	Chromium
Lead	Dibromochloromethane	Vanadium
Mercury	Boron	1,2-dichlorobenzene
Nickel	Chlorobenzene	1,3-dichlorobenzene
Selenium	Beryllium	1,4-dichlorobenzene
Silver	Gross alpha	Toluene
Zinc	Gross beta	Xylene
Sulfate	Radium 226	

Source: 33 CSR1. Appendix V Leachate Sampling Parameters for Facilities Accepting Drill Cuttings and Associated Drilling Waste. June 1, 2015

The Rulemaking does not require analysis for the great majority of these components that are reasonably anticipated to be generated from drill cuttings that other states have identified as contaminants of concern and leachable from drill cuttings. Therefore it is not reasonable to conclude that this Rulemaking will protect against pollution and safeguard human and environmental health and safety.

Because beneficial use products that contain drill cuttings that will be ingredients in construction products that people are exposed to, the Commission must amend its Rulemaking so that the concentrations of contaminants in drill cuttings can be compared to human-health risk benchmarks. In its Rulemaking, the Commission proposes to compare testing results to hazardous waste disposal criteria under the U.S. Resource Conservation and Recovery Act (RCRA).

The RCRA Hazardous waste criteria are appropriate for making landfill disposal decisions, where the question is the level of protectiveness provided by a solid (industrial and municipal) waste/non-hazardous (RCRA Subtitle D) landfill vs. a hazardous waste (RCRA Subtitle C) landfill. Beneficial use products will not be placed into landfills, they will be placed in roads, concrete, and fill material directly in the human environment, without any of the human health and environmental exposure protections provided by landfills (specific siting requirements prohibiting construction in environmentally sensitive areas, use of liners to contain waste and collect and treat liquid leachate; environmental monitoring systems to protect groundwater and gaseous emissions). Drill cutting contaminant concentrations should appropriately be compared to human health benchmarks, such as those provided under the Texas Risk Reduction Program (TRRP) Protective Concentration Levels (PCLs).

Drill cuttings batches for beneficial reuse applications should be subjected to the testing criteria (analytical methods and protective concentration levels) for all of the contaminants known to be present at variable concentrations in drill cuttings including the full target analyte lists for VOCs, SVOCs, PAHs, heavy metals and radionuclides.

5.1.1 Leaching testing methods

Research by the state transportation department (TxDOT) into the suitability of drill cuttings for roadbase applications (UTA-CTR, 2024) utilized the U.S. EPA Leaching Environmental Assessment

Framework (LEAF) (EPA, 2019b) to evaluate the leaching of contaminants under a wide range of environmental conditions.

The LEAF framework is more flexible and likely better representative of the range of environmental settings applicable to beneficial use of drill cuttings as compared to the TCLP and SPLP methods specified by the Rulemaking alone.

The U.S EPA has validated the LEAF framework for evaluating leachability of inorganic constituents, including radionuclides. The Commission should add leachability assessment and criteria via the LEAF framework to the Rulemaking. The LEAF framework uses four different tests to account for variation in the major factors known to affect leaching behavior (ie. pH, liquid/solid ratio, rainfall infiltration rate, material form) whereas the SPLP and TCLP methods only contemplate single scenarios, respectively.

While it is understood that the TCLP method is required to make determinations whether a waste is classified as a toxicity characteristic hazardous waste under RCRA, adding the LEAF framework will better account for the variable conditions affecteing leachability of beneficial use products that contain drill cuttings and should be added to the Rulemaking.

5.1.2 PFAS

The fluid and foams that are used for both drilling and hydraulic fracturing of gas wells can contain fluorinated compounds such as per- and polyfluoroalkyl substances (PFAS) (Hussain et al., 2022; Glüge et al., 2022; Murphy and Hewat, 2008).

Studies conducted by PADEP and the U.S. Geological Survey have shown that PFAS from oil and gas development regions in Pennsylvania is associated with combined sewage outfalls, indicating a relation between oil and gas operations and either surface runoff, or waste processing through sewage systems (Breitmeyer et al, 2023).

In 2024, USEPA has designated two types of PFAS, perfluorooctanoic acid (PFOA) and perfluorooctanesuflonic acid (PFOS) as hazardous substances under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA).

Failure to evaluate beneficial reuse materials for these and other PFAS compounds leaves the door open for future cleanup liability under CERCLA. Testing should be performed before products are released for beneficial use to prevent their further release to the environment.

In alignment with 16 TAC §4.208, the Texas Natural Resources Code, and the Texas Water Code, it is recommended that the Commission add a requirement for analysis of PFAS compounds to the Rulemaking to ensure that PFOA and PFOS will not cause the pollution of surface or subsurface water, a present a threat to public health and safety in the beneficial use of drill cuttings.

5.1.3 Process knowledge

There are likely additional contaminants in drill cuttings that are included as additives to the drilling process that this author has not discussed. It is recommended that the Commission utilize its process knowledge and authority to require permittees and generators of drill cuttings to disclose and test treated drill cuttings to ensure that any contaminants do not persist in treated drill cuttings. Even if protected by confidentiality or “trade secret” provisions, permittees could still conduct and report testing results as a permit condition to confirm that any potential contaminants do not persist after treatment of drill cuttings for beneficial reuse.

6. THE PROPOSED RULEMAKING DOES NOT ALIGN WITH GOOD PRACTICES IN OTHER STATES

Not only does this Proposed Rulemaking diverge from established science, the Proposed Rulemaking diverges from the approach taken by many other oil and gas producing states toward management of drill cuttings. Other states do not allow the range of reuse contemplated by this Proposed Rulemaking in large part due to the high concentrations of contaminants of concern (COCs) contained in drill cutting mixtures compared to those naturally present in surface environments. This is especially true for cuttings generated from the horizontal portions of the well bore advanced through the oil or gas bearing target formation, which is known to have more chemicals of concern based on higher levels of NORM and additional contaminants introduced by the type of drilling muds used to navigate these horizontal portions. There are also significant technical challenges to treatment and management of drill cuttings that are complicated by the intermixing of the different chemical types: inorganic, organic, and radioactive, as well as the chemical challenges from exposing contaminants to surface environments that differ vastly from the oxidation state, temperature, and pressure environments of the geology from which drill cuttings are mined.

Significant observations pertaining to management of drill cuttings from some of the other major oil and gas producing states are discussed in the following subsections.

6.1 West Virginia

Despite its comparatively small size, West Virginia is estimated to contain the third-highest shale gas reserves of U.S. states and 10% of the nation's total shale gas reserves, with 95% of its production from the Marcellus and Utica-Point Pleasant shale formations (EIA, 2024a).

6.1.1 Because of environmental concerns, as a practical matter, drill cuttings in West Virginia are landfilled, not reused

In West Virginia, all drill cuttings and associated drilling mud (collectively “drill cuttings”) generated from horizontal well sites (a term that generally aligns with the Commission’s definition of drill cuttings (16 TAC §4.204)), must be disposed of in an approved solid waste facility, or if the surface owner consents, may be managed on-site (WV Code §22-6A-8(g)(2)).

In practice, on-site disposal of drill cuttings is discouraged because of the potential for pollution, and the state’s solid waste management rules were updated in 2015 to allow disposal of drill cuttings at state municipal solid waste (MSW) landfills.

As part of the Rule revision, West Virginia concluded that due to high concentrations of leachable contaminants, land application of drill cuttings generated from mud drilling operations should not be allowed, but did note that some states including Oklahoma, Louisiana and Texas, drill cuttings have been land applied on farmland (CEGAS, 2015). In the process of West Virginia’s review, it noted that lower concentrations of leachable contaminants were generated from the portion of the well bore drilled using air rotary methods were lower than when drilling mud or additives were used. This suggests that different waste management approaches may be possible if the cuttings recycler is able to verify how the batch of cuttings was produced. However, the Rule addresses all drill cuttings together as one regardless of likely contaminant levels, thus to be protective of human health and the environment, the parameters and testing required by the rule must assume the worst-case scenario---that the drill cuttings are from the horizontal bore. And testing the horizontal bore is in fact what West Virginia requires, as is explained below.

6.1.2 Beneficial use of drill cuttings would require meeting radiation limits lower than those in Texas and would prohibit ‘‘down blending’’

West Virginia considers beneficial reuse of materials that are applicable to drill cuttings in its radiological health rules (64CSR23). West Virginia defines TENORM as:

> *"naturally occurring radionuclides whose concentrations are increased by or as a result of past or present human practices. TENORM does not include background radiation or the natural radioactivity of rocks or soils."*

To be available for purposes of beneficial reuse, drill cuttings would have to meet the TENORM exemption criteria for combined Radium 226 and Radium 228 below 5 pCi/g, excluding natural background (64CSR23 16.4.a).

Specifically, the practice of "down blending" or mixing with other materials to reduce the radioactivity levels to achieve exemption criteria is prohibited.

As a practical matter then, drill cuttings in West Virginia are exclusively disposed in municipal solid waste landfills (MSWs).

6.1.3 Disposal of drill cuttings requires sampling from the horizontal portion of the bore, and for additional important parameters

West Virginia defines drill cuttings and associated drilling waste to include both the solid earthen material as well as any intermixed additives, such as drilling mud, that are generated by the drilling process. These materials are allowed to be disposed in MSWs. Materials such as flowback fluids, brine or formation water generated from wells and after drilling is complete, or other solids or liquids such as tank bottoms, pit contents, fracturing sand or proppants are specifically excluded from disposal in MSWs (33CSR 5.6.a.).

Prior to authorization to dispose of drill cutting in a MSW via a minor permit modification Special Waste Permit, West Virginia's 33CSR 5.6.c.1.A. requires collection and analysis of a composite sample from the horizontal or lateral portion of each well bore that must be used for landfill waste profiling based on volumes of material to evaluate suitability for landfill disposal (33CSR 5.6.c.1.B).

Drill cutting waste profiling must include analysis for the following constituents via approved SW-846 methods shown below in Table 1.

Table 1: WV Required drill cutting waste profiling parameters and methods

Analytical Parameter	Analytical Method
Toxicity Characterization Leaching Procedure (TCLP) Metals	EPA Method 1311
TCLP Volatile Organic Compounds (VOCs)	EPA Method 8260B
TCLP Semi volatile Organic Compounds (SVOCs)	EPA Method 8270C
Total Petroleum Hydrocarbons (TPH)	EPA Method 8015C

Notes: Source 33 CSR 1 §5.6.c.1.C.1. Sampling results for these parameters must not exceed the limits of 40 CFR § 261.24.

In my opinion, this list is still incomplete because these waste profiling requirements lack analysis for any radiological parameters (more on that below), or for two highly mobile constituents often associated with drilling waste, bromide and chloride. However they do include analysis for numerous individual VOCs and SVOCs that may be soluble and have more concentration limits than could be assessed by TPH analysis --- and these analytes are overlooked by the Commission in the

Rulemaking. Analytical results must definitively demonstrate attainment of leachability limits under 40 CFR § 261.24 for each of the target analytes included within the analytical methods listed in Table 1.

In addition, any landfill permitted to accept drill cuttings ***that does not transfer leachate off-site for additional treatment*** must test its leachate for a specific list of parameters the state considers parameters of concern for drill cuttings (See Figure 8). It is noted that this list includes numerous parameters not included in the Proposed Rulemaking requirements for testing of treated drill cuttings for beneficial use, even though the uses contemplated by the Proposed Rulemaking would result in leachate staying on-site without receiving additional treatment.

Furthermore, even though radiological testing is not specified in West Virginia's 33 CSR 1 sec. 5.6.c.1.C.1 (See Table 1 above), West Virginia does recognize the radiological risk because it requires Radium 226 and 228 testing for the horizontal portion of the well bore and screening of waste loads via portal gate monitoring (33CSR 5.6.d). If gate monitoring shows exceedances of an external dose of 10 uR/hr, then confirmatory analytical testing is required to ensure that combined activities for Radium 226 and Radium 228 do not exceed 5pCi/g or greater excluding local background. To be clear, West Virginia's method of gate monitoring is flawed[5] and should not be adopted by the RRC, but it shows West Virginia's recognition of the potential for radionuclides as constituents of concern and recognizes that even 5 pCi/g would render drill cuttings unsuitable for MSW landfill disposal, much less beneficial reuse.

Instead, for definitive compliance, sampling and laboratory analysis of drill cuttings is warranted. As discussed in forthcoming sections, Ohio requires this approach of requiring analytical testing of all drill cuttings before they leave the drilling site to evaluate suitability of disposal in state landfills and determination of whether drill cuttings are classified as TENORM.

6.2 Pennsylvania

Due increased natural gas development in the Marcellus Shale, Pennsylvania's proven reserves more than quadrupled from 2011 to 2021. Pennsylvania is the second-largest net supplier, after Texas, of energy to other states and is second only to Texas in estimated total proved natural gas reserves (EIA, 2024b).

Pennsylvania allows disposal of its drill cuttings into municipal and commercial solid waste landfills. Drill cuttings from any portion of the well bore are also allowed to be managed or processed at the drill site, or potential other locations, but require an alternate waste management practice permit OG-71A.

Under 25 Pa. Code § 78a.61, Pennsylvania also allows disposal of drill cuttings generated from <u>above the surface casing seat</u> by land application after meeting certain siting and post application restoration requirements. The surface casing seat refers to the casing installed to isolated and protect drinking water supplies, or 50-feet below the deepest fresh groundwater, from the well bore. This approach avoids boring contact with oil and gas producing strata or strata containing radionuclides several to many times background surface soils and therefore avoids these as potential contaminants of drill cuttings. **The Commission could have considered a similar approach**

[5] Because of the distance separating portal monitoring equipment sensors from transport containers and shielding of the weak gamma radiation emissions generated by Radium by both the matrix of the drill cuttings waste material and transport container walls, it is questionable that portal gate monitors are capable of determining the combined Radium 226 and Radium 228 activity of drill cuttings. Therefore, in this author's opinion, it is highly likely that loads of drill cuttings that contain significantly higher activities for combined Radium than the state's rejection criteria of 5pCi/g above local background are routinely disposed in West Virginia MSW landfills.

to segregate drill cuttings for beneficial reuse consideration based on this, or a similar limitation to vertical depth, but did not.

6.2.1 Beneficial use

Pennsylvania also contemplates beneficial use of drill cuttings under its Solid Waste Management Rules under a Residual Waste Permit under 25 Pa. Code § 287.102, but to-date only three such permits have been issued since 2011. Each permit identifies research and development purposes for either capping material, construction material, or road base as the permitted activity. None of the permits have been active since 2017 (PADEP, 2024a) or were available for review.

To re-use any type of formerly contaminated material (drill cuttings or otherwise) as clean fill that is permitted for unrestricted, unlimited use (i.e., public or residential use), Pennsylvania requires compliance with its due diligence and testing requirements. To meet requirements for re-use, fill must be tested utilizing a statistically robust sampling strategy and laboratory analysis for all contaminants reasonably known or suspected to be present to confirm attainment of the state's health risk-based criteria. Applicants must also certify that attainment has been demonstrated and submit the form to the state. (PADEP, 2024b).

The Commission should use a similar approach to PADEP's Clean Fill Policy for any beneficial use materials, as part of its strategy to not cause the pollution of surface or subsurface water or a threat to public health and safety in alignment with 16 TAC § 4.208.

6.3 Ohio

Ohio is also a significant producer of oil and gas and includes portions of the Utica and Marcellus shale formation. It also takes a more protective approach to radioactivity than the Rulemaking even for disposal.

In Ohio, all oil and gas drilling related wastes, except brine, must be tested before leaving the well site to determine the activities for Radium 226 and Radium 228. Ohio requires definitive determination of Radium 226 and Radium 228 activities only by approved methods, including EPA Method 901.1M that can be used for both Radium 226 and Radium 228 in a single test. EPA Method 901.1M is a modification of a water analytical method that can be used for solids and relies on gamma spectrometry analysis after a 21-day ingrowth period. (ODH, 2019).

Ohio, similar to Texas, does not classify drill cuttings as NORM unless radioactivity is elevated to a level greater than is found in its natural state. However, as discussed previously, how one defines "natural" state has a significant effect.

Ohio considers the natural state of NORM that is present in the local surface soil background as the baseline for determining whether NORM is elevated in solid wastes. As a default position, unless a person demonstrates otherwise, Ohio considers 2 pCi/g as the natural background activity for combined Radium 226 and Radium 228 (ODH, 2019).

Ohio classifies solid waste, including oil and gas waste, as TENORM if concentrations for solids are 5 picocuries per gram (5 pCi/g) or greater for combined Radium 226 / Radium 228, excluding natural background radiation. So, unless a person documents that a site-specific background activity for combined Radium 226 and Radium 228 is greater than 2 pCi/g, then a solid waste is TENORM at 7 pCi/g, more than 4 times lower than Texas' 30 pCi/g combined Radium 226/228 exemption criteria for oil and gas waste (16 TAC §4.603). By this criteria, Texas allows much more NORM into the environment than many other oil and gas producing states.

Ohio does not allow TENORM to be disposed in Ohio landfills or at oil and gas drilling sites but will consider dilution to reach permissible levels through a special permit. If allowable TENORM levels cannot be reached, the TENORM waste must be disposed at a low-level radioactive waste disposal facility (ODH, 2024).

6.3.1 Beneficial use

Use of drill cuttings off-site for fill or other beneficial uses, requires site specific approval Ohio EPA, Division of Materials and Waste Management and is based on statistically representative sampling and comparison to health-based screening levels. Ohio's approach in this regard improves on that in the Commissions' Rulemaking since it requires comparison of contaminant concentrations to health-based screening levels rather than much more lax hazardous waste classification screening levels. The Commission should utilize health-based screening levels to screen contaminant concentrations in beneficial use materials to be protective of human health and the environment.

7. ALIGNMENT WITH OTHER TEXAS REGULATIONS

At present, the Proposed Rulemaking will allow release of materials for beneficial reuse that may have significantly higher levels of contaminants than allowed by other sections of Texas code for public exposure. Testing requirements are lacking to compare treated drill cuttings for beneficial reuse "apples to apples" to criteria used by other Texas agencies for the same contaminants under similar human and ecological exposure scenarios.

Several examples are provided that demonstrate this discontinuity. In my opinion, the Commission should withdraw the Proposed Rulemaking and before reproposing, it should explicitly consider the technical and procedural methods used by other Texas agencies when regulating substances containing radioactive materials. To do otherwise risks arbitrary-and-capricious decision-making. Specifically:

- TAC 30 §336.203 states "no person shall dispose radioactive material unless that person has a license from the Texas Commission on Environmental Quality, or an exemption under Texas Health and Safety Code, §401.106(a)."
- Texas Health and Safety Code Section allows exemption for sources of radiation that "will not result in a significant risk to public health and safety and the environment." (Tex. Health & Safety Code § 401.106 (b)(2)).
- Texas Radioactive substance rules 30 TAC §336.229 provides that: "No person shall reduce the concentration of radioactive constituents by dilution to meet exemption levels established under the Texas Health and Safety Code, Chapter 401, §401.106, or change the waste's classification or disposal requirements. Radioactive material that has been diluted as a result of stabilization, mixing, or treatment, including, but not limited to, Resource Conservation and Recovery Act (RCRA) Land Disposal Restrictions (LDR) treatment, or for any other reason, shall be subject to the disposal regulations it would have been subject to prior to dilution."
- 30 TAC §336.207 provides that radioactive licensee applicants who intend to engage in near-surface land disposal of low-level radioactive waste demonstrate *"…financial capability to conduct the proposed activity, including all costs associated with decommissioning, decontamination, disposal, reclamation, and any long-term care and surveillance*."

The Rulemaking does not provide justification these deviations from other Texas statutes crafted to manage NORM and other radioactive material in the state.

7.1 ALARA

Another principle that the Commission does not appear to consider in this Proposed Rulemaking--- even though it is an integral part of the State's regulation of radioactive materials in other contexts--- is the principle of "as low as reasonably achievable" (ALARA). ALARA is defined in 30 TAC 336 and is an industry guiding principle for management of radioactive material and radiation safety. 25 TAC §289.202(2) pertaining to radiation control requires use, to the extent practicable, procedures and engineering controls based upon sound radiation protection principles to achieve occupational doses and public doses that are as low as is reasonably achievable (ALARA).

The U.S. Centers for Disease Control and Prevention (CDC) provides a practical interpretation of ALARA to mean avoiding exposure to radiation that does not have a direct benefit to you, even if the dose is small.

The Rulemaking does not follow the ALARA principle, or even make it possible to evaluate alignment with it since testing of radionuclides is not included in the testing requirements for treated batches of drill cuttings for beneficial use.

8. LACK OF RISK ASSESSMENT

The Rulemaking appears to lack foundation in an exposure risk assessment that evaluates potential threats to public health and safety. Risk assessments are common prerequisites to this sort of Rulemaking. Such risk-assessment analysis requires:

> (1) consideration of plausible environmental fate and transport mechanisms for all proposed uses of these drill cuttings (see 4.301(b) : construction of oil and gas lease pads or gas lease roads; construction of county roads; concrete bulking agent; oil and gas waste pit cover material; treated aggregate; closure or backfill material; berm material; or construction material) and considering potential constituents of concern (as described above, including NORM, heavy metals, hydrocarbons);
>
> (2) identification of all potentially affected current and future receptors (including both ecological and human receptors, like workers, residents, children and other sensitive populations); and
>
> (3) evaluation of any complete or potentially complete current and future exposure pathways (including ingestion, contact, inhalation).

Robust risk assessments are iterative processes that include opportunities for public comment and peer review.[6] Examples of risk assessments conducted for NORM are provided below as context. As will be shown, these following risk assessments demonstrate unacceptable human exposure to radiation from NORM containing materials that are very similar to those posed by the Rulemaking.

To my knowledge, the RRC has not conducted any risk assessment for the proposed uses of cuttings, and the only record the RRC has offered to support its proposed changes to Chapter 4 Subchapter B Division 7's beneficial use of drill cuttings is S.B. 1541, which is not a risk assessment. I understand that TxDOT is conducting an on-going study with the RRC and University of Texas about uses of drill cuttings in certain select applications (UTA-CTR, 2024), but that study is not complete, is not a risk assessment, does not examine the full range of uses contemplated by the rule, does not present any testing or analysis for NORM, and looks at only two sites in Texas even though it is common knowledge that drill cuttings differ greatly across sites and even day-to-day.[7]

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[6] https://www.epa.gov/risk/about-risk-assessment

[7] For example, what works in East Texas, won't work in the Permian Basis.

In my opinion a robust risk assessment---with opportunity for public comment and peer review---is necessary before a rule about beneficial use of drill cuttings could be proposed.

As such, there can be **no confidence that the Rulemaking will not allow pollution of surface or subsurface water in the state as per 16 TAC §4.101(a) and be protective of human health and safety as required by §4.208(b)(2).**

Moreover, the levels of NORM allowed by this Rulemaking (combined Radium at 30 pCi/g, or other radionuclides at 150 pCi/g) exceed the levels that other risk assessments applications have found to be both protective and achievable, as the following explains.

8.1 Federal NORM Risk Assessments

8.1.1 Protective and achievable NORM dose levels

In 1997, EPA established, through risk assessment, that a 15 millirem per year or less effective dose equivalent (EDE) to current and future users from exposure to all radioactive contaminants of concern through all media (soil, ground water, surface water, sediment, air, structures, and biota) is generally protective of human health (EPA, 1997). This dose limit and an understanding of plausible exposure scenarios can be used to calculate remediation goals, such as concentration limits for contaminants in soil, water, air, etc.

This dose level equates to an approximately 3E-04 excess lifetime cancer risk, which is even slightly above 1E-04 to 1E-06 risk level normally acceptable for EPA lead clean up actions. The includes the effective doses from both background and man-made sources, although cleanup below natural background conditions is not normally performed. EPA found that a 15 millirem per year dose level is both sufficiently protective and achievable (EPA, 1997, Attachment B, pg 2).

8.1.2 NORM in land-applied oil and gas waste

In 1998, the U.S. Department of Energy (DOE) Argonne National Lab utilized RESRAD (Version 5.782) to model the doses that may result from direct gamma exposure, inhalation of radon, and ingestion of local soil and produce that may result from land application of oil and gas productions wastes that contain TENORM (EPA, 2019a). This scenario is similar to how drill cuttings could be placed according to the Rulemaking (see 4.301(b), DOE found that a surface soil activity of 5 pCi/g Radium 226 above background resulted in an additional 30 milliremi/yr exposure from gamma radiation --- in other words, twice the acceptable dose recommended by the 1997 EPA study from radium-226 alone. Meanwhile, Radon accumulation in the home increased the modeled doses to 60 millirem/yr (EPA, 2019a) --- four times the acceptable level as compared to the 1997 EPA study.

The DOE authors recommended that states that allow landspreading of oil and gas exploration and production waste to activities greater than 5 pCi/g above background should consider establishing policies that restrict future land use or, at a minimum, ensure that future landowners are advised of the activity and the potential associated health risks. (EPA, 2019a, Section 7.2.1). At a minimum this would require testing the waste to establish its levels of radioactivity, which the rule does not require.

8.1.3 NORM in buried Coal Combustion Residuals

More recently, EPA's assessment of the risks associated with management of coal combustion residuals (CCR) identified unacceptable levels of human radiation exposure risk posed by buried CCR (EPA, 2023). Note, CCR can have lower levels of radioactivity than drill cuttings, and indeed the radium and uranium activities that EPA used in this risk assessment were more than four times lower (combined Radium 226/228 6.7 pCi/g – See EPA 2023, Table 5-3) than the up to 30 pCi/g that would be permitted by the Rulemaking (16 TAC §4.603).

In addition, EPA's models showed that the activity of radium 226, and resulting decay to Radon 222, was the primary driver of risk to human receptors from buried CCR (EPA, 2023). Elevated health risk was driven not by Radium itself, but exposure to its radioactive progeny, Radon 222 and its own subsequent alpha and beta radiation emitting decay progeny that reached human receptors above the ground surface via the gaseous migration of Radon 222.

EPA's CCR risk assessment raises concerns relevant to the Proposed Rulemaking in two ways.

First, the rule would functionally allow radioactivity levels in beneficial use drill cuttings of radium at 30 pCi/g, or other radionuclides at 150 pCi/g, which is even higher than those modeled in the CCR study. These activity levels are already much higher than natural soil background and could reasonably be even higher in end products if concentrated through treatment and recycling processing. **But the Rulemaking provides no way of knowing Radium or other NORM levels since there is no radionuclide testing of treated drill cuttings.**

Second, EPA's modeled CCR scenarios would presumably provide *less* exposure than many of the proposed scenarios for beneficial use drill cuttings (4.301(b)).

For example, in the case of beneficial use of drill cuttings, it is completely plausible that future exposure pathways may exist that provide little to no shielding to gamma radiation (contrary to the models in the CCR study). Little shielding from gamma radiation would be expected if drill cuttings were used for road construction as proposed, or used as additives to concrete, or for construction fill—or if those same materials are later disturbed or again recycled into other applications many years from now. The proposed rules also would allow the material to be used as cap material for waste pits, generic closure or backfill material, berm material, or other construction fill. There's no prohibition that this material could wind up in residential constructions, at playgrounds, in parks, and places of worship. Even if shielding was considered, e.g., if the fill was placed under buildings, it could also create radon and vapor intrusion risks that would need to be evaluated via risk assessment. In these scenarios there may be combined human exposure to alpha, beta, and gamma radiation for which exposure risk needs to be assessed to comply with 16 TAC §4.208.

As for identifying all potential current and future receptors, drill cuttings that contain many times background levels of radionuclides (as the 1998 DOE study predicts) may provide exposure to current or future landowners, or users of products that contain recycled materials carrying those contaminants, or ecological receptors. To evaluate threats to human health and the environment, persons responsible for management and use of products destined for reuse must know the concentrations or activities of chemicals present and potential exposure routes to current and future receptors.

Future use scenarios must also contemplate the handling and disposition of materials that are permitted for beneficial reuse. For example, mechanical or chemical forces that may affect the leachability of contaminants many years from now. This could include human intervention such as demolition or construction activities or natural events including flooding, tornados, hurricanes, and general surface subsidence.

9. CONCLUSION

Adding new drill cutting contaminants as ingredients of beneficial use products into surface environments where they can be broken down and released over time requires consideration of future land use and long-term stability of the beneficial product. Natural weathering or physical agitation during road maintenance/utility work, or even future recycling of road-bed materials, warrants that environmental contaminants in beneficial use materials (drill cuttings) are kept very near the current natural background levels where they are placed to prevent a source for future contamination. Also, future land uses will undoubtedly change over time, years, decades or even much longer, so contaminants embodied in beneficial materials must not be allowed to inhibit future unlimited and unrestricted land use.

Assessment of drill cutting suitability for use in beneficial products should be conducted in accordance with human and ecological health risk based methods and criteria and not solely hazardous waste disposal criteria. The Rulemaking proposes drill cuttings for use in construction of oil and gas lease pads or gas lease roads; construction of county roads; concrete bulking agent; oil and gas waste pit cover material; treated aggregate; closure or backfill material; berm material; or construction material. These uses place products and the contaminants they contain directly into the human and ecological environment without any of the protections provided by landfills.

The sheer quantity of NORM material brought into the surface environment in drill cuttings is unprecedented and warrants a new approach to management of drill cuttings than has been in use to date. A careful accounting and thorough assessment of the human health and environmental risks posed by drill cuttings is absent from the Rulemaking. The Rulemaking should move forward only after these assessments are completed, peer-reviewed, validated, and a public participation process is completed.

In this author's opinion, without further amendment to the Rulemaking, it is more likely than not that beneficial use of drill cuttings will cause alteration of the chemical or biological quality of air, groundwater, surface water, soils, and sediments in Texas that is detrimental to the health of human and ecological receptors.

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APPENDIX A: MARC GLASS CV

MARC EDWARD GLASS

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Professional Profile

Downstream Strategies, LLC Morgantown, W.Va.
Principal/Member, 2012-present

Cira and Associates Consulting, LLC Morgantown, W.Va.
Managing Partner, 2004-12

August Environmental, Inc. Morgantown, W.Va.
Senior Project Manager/Senior Scientist, 2002-04; Project Manager, 2001-02;
Environmental Scientist, 1999-2001

Education

West Virginia University, Morgantown Morgantown, W.Va.
Graduate studies and research in Soil Sciences, 1996-1999.
B.S. Environmental Sciences awarded 1993.

Projects

Mr. Glass is a Principal and Member/Manager of Downstream Strategies, LLC where he provides senior technical oversight and leads the Environmental Monitoring and Remediation Program. He is responsible for overall profit center management, strategic planning, and mentorship for a staff of twenty environmental professionals. His project work focuses on evaluation of the environmental fate and transport of contaminants and development of remedial approaches with over 24 years of experience in environmental consulting and management, including 20 years as a West Virginia Licensed Remediation Specialist (LRS). His experience includes leading project teams in the risk-based context of the West Virginia Voluntary Remediation and Redevelopment Program (VRP), Pennsylvania Department of Environmental Protection Land Recycling Program (Act 2), and other state and federal regulatory programs. He has managed hundreds of projects involving brownfield redevelopment; environmental due diligence; and remediation of sites impacted by heavy metals, petroleum products, PCBs, chlorinated solvents, and other CERCLA-regulated hazardous substances. He currently serves as the Remediation Technical Advisor overseeing the Crosby Harvey Dioxin cleanup settlement near Houston, TX. From 2011-2017, he served as the court-appointed Technical Advisor implementing the Perrine Dupont Remediation Settlement cleanup program. Mr. Glass frequently provides expert consulting pertaining to environmental sample program design for all environmental media, data collection and analysis, and provides expert technical reports and testimony in county, state, and federal courts. He is adept at engaging communities, regulatory agencies, technical professionals, and other project stakeholders to clearly communicate complex scientific principles, both in person and utilizing electronic formats.

Scientific analyses

Ambient air monitoring

- Designed and implemented a multiple phase ambient air monitoring program to investigate potential radiological particulate emissions during demolition of an industrial storage facility. Developed quality assurance/quality control protocols and performed field sampling events. Performed review of laboratory analytical data and comparison to multiple acute and chronic exposure criteria (Downstream Strategies, 2024, confidential client).
- Designed and implemented a multiple phase ambient air monitoring program to investigate potential impacts from a multiple well, non-conventional shale gas development site. Investigation coordinated to capture temporal effects and discrete stages of well development. Developed quality assurance/quality control protocols and coordinated field sampling events and technical staff. Performed review of laboratory analytical data and comparison to multiple acute and chronic exposure criteria (Downstream Strategies, 2012, confidential client).

- Performed analysis and evaluation for volatile organic compound vapor intrusion pathways at multiple hazardous waste release sites in Pennsylvania and New Jersey (Cira and Associates Consulting LLC 2004-12, various private clients).

Soil and settled particulate contamination and remediation

- Technical Advisor overseeing site characterization and cleanup of Dioxin in soil and interior settled dust for the Crosby-Harvey class action settlement in The United States District Court for The Southern District of Texas Houston Division. (Downstream Strategies, 2024-current, Crosby Harvey Settlement).
- Led investigation of private residential properties impacted by gross airborne particulate deposition from demolition of an industrial structure in West Virginia (Downstream Strategies, 2003-2024, private clients).
- Designed a sampling and assessment program and prepared cost estimates to implement property specific evaluation of a 5-mile circumference area impacted by historical industrial emissions in Pennsylvania. Prepared a remedial design and cost estimation for exterior soil remediation and cleanup of residential interiors. (Downstream Strategies, 2019-2023, confidential client).
- Lead a multi-phased, multi-media field sampling program, including exterior soil and interior dust, over a 7-mile circumference study area to evaluate radionuclide concentrations and geospatial distribution in southern Illinois. (Downstream Strategies, 2018-2024, confidential client).
- Prepared a remedial design and cost estimation for excavation and replacement of soils contaminated by multiple discrete releasee events from a subsurface piping system transferring fluids between oil and gas production pad sites. (Downstream Strategies, 2020, confidential client).
- Lead investigator responsible for design and implementation of a large-scale, multi-media field sampling program to evaluate environmental releases from an industrial fire at an organic peroxide chemical production facility in southeast Texas. The investigation area extended for over nine square miles and required multiple phases. (Downstream Strategies, 2017, confidential client).
- Designed and implemented a field sampling program for the evaluation and characterization of heavy metals impacts to residential structures and surface soils at properties impacted by airborne emissions from historical zinc smelter operations in southwestern Pennsylvania. (Downstream Strategies, 2017-2019, confidential client)
- Prepared written technical analysis of soil sampling data pertaining to environmental contamination from various oil and gas production sites in West Virginia (Downstream Strategies, 2012-2014, confidential clients).
- Performed soil boring and field sampling programs to investigate environmental releases from un-conventional shale gas development activities (Cira and Associates Consulting and Downstream Strategies, 2011-present, for confidential clients).
- Assessed surface and sub-surface soils for impacts from natural gas wells and coal mines (Downstream Strategies, 2012-present, for various clients).
- Court-appointed Remediation Technical Expert for oversight of Class Action Property Remediation Program. Presented at numerous town-hall meetings and court hearings to communicate complex technical concepts and remedial approaches to a diverse public audience. Developed sampling strategy to delineate contemporary distribution of heavy metals impacts from a former zinc smelter operation for over 200 residential and commercial properties. Used GIS tools to perform spatial evaluation of large quantities of data. Performed statistical analysis of discrete data sets to evaluate inclusion of additional properties to remediation program. Drafted scope of work documents and provided technical consultation to Settlement Administrator during public outreach program, field sampling program and remediation contractor selection. (Cira and Associates Consulting and Downstream Strategies, 2011-present, for confidential client).
- Source soil excavation of petroleum contamination at multiple underground storage tank sites in West Virginia, Maryland, Ohio and Pennsylvania (Cira and Associates Consulting, 2004-12, for various private clients).
- Served as primary technical resource for delineation of subsurface contamination, pilot study performance evaluation, and remedial technology cost-benefit analysis (Cira and Associates Consulting, 2004-12, for various private clients).
- Provided technical evaluation and budget/cost analysis to assist clients in selecting optimal mitigation strategies for contaminated properties. Fostered relationships between clients and regulatory officials to expedite project timelines. Operated within multiple federal, local, and state regulatory frameworks and collaborated with regulatory and local officials to perform geologic investigations within public right-of ways (Cira and Associates Consulting, 2004-12, for various private clients).

Groundwater contamination and remediation

- Licensed Remediation Specialist responsible for remedial actions to address inorganic contaminants exceeding West Virginia Groundwater De Minimis Standards. Completed a de minimis human health and ecological risk assessment and implemented institutional controls to eliminate human health exposure. Designed and currently overseeing implementation of a monitored natural attenuation groundwater program. (Downstream Strategies, 2024, City of Thomas, West Virginia).
- Designed and implemented a surface water and sediment monitoring program to investigate chlorinated solvent and heavy metal contamination originating from an adjacent property in eastern West Virginia (Downstream Strategies, 2014, confidential client).
- Performed field investigation and technical consultation pertaining to potential adverse impacts to multiple private drinking water wells in northwestern Pennsylvania from unconventional oil and gas development activity (Downstream Strategies, 2014, confidential client).
- Conducted review of private drinking water well sampling data collected by operator in response to a spill of oil and gas drilling fluids in north central West Virginia. Provided written summary with technical recommendations for on-going monitoring approaches (Downstream Strategies, 2013, confidential client).
- Prepared written technical analysis of surface and groundwater sampling data trends for an oil and gas production site located on private property in West Virginia (Downstream Strategies, 2012, confidential client).
- Assessed water wells and surface waters for impacts from natural gas wells and coal mines (Downstream Strategies, 2012-present, for various clients).
- Conducted site assessments, conceptual site model development, sampling and analysis plans, ecological risk screening, participated in residual risk assessments, and drafted remedial action work plans for sites entering the West Virginia Department of Environmental Protection Voluntary Remediation and Redevelopment Program (VRRP) (August Environmental, Inc. and Cira and Associates Consulting LLC, 2003-12, various private clients).
- Prepared Site Characterization Plans, Corrective Action Plans, NPDES permit applications, Quarterly Monitoring Reports associated with corrective actions for leaking underground storage tank (LUST) facilities. Responsibilities included technical evaluation of remedial alternatives and remedy selection systems (Cira and Associates Consulting LLC, 2004-12, various private clients).
- Responsible for installation and operation and maintenance of dual phase, ground-water table suppression, soil vapor extraction, air sparging and oxygen release compound remediation systems (Cira and Associates Consulting LLC, 2004-12, various private clients).
- Conducted numerous investigations to delineate hydrocarbon contamination originating from leaking underground storage tanks located in Pennsylvania and West Virginia (Cira and Associates Consulting LLC, 2004-12, various private clients).
- Evaluated a chlorinated solvent groundwater plume at an industrial property along the Ohio River in West Virginia. Performed comprehensive technical review of existing monitoring data and developed scope of work for evaluation during a real estate transaction. Oversaw installation of Geoprobe® boreholes, performed groundwater sampling, installed and developed monitoring wells using hollow-stem auger and prepared reports and graphic presentations utilized in litigation support. (August Environmental, Inc. and Cira and Associates Consulting LLC, 2003-05, private client).
- Provided technical support to staff during hydrogeologic investigations and field operations. Conducted geostatistical analysis for long-term monitoring projects to assure data quality (August Environmental, 2001-02, various private clients).
- Involved with an emergency response groundwater/gasoline recovery system implemented to prevent offsite migration of non-aqueous phase liquid plume. Experience included groundwater/gasoline piezometric mapping for tracking contamination migration, preparation of permits for all aspects of construction and hazardous materials storage, equipment selection, and installation. Interim recovery performed while complying with orders from the local lead agency not to depress the groundwater table until site delineation was complete (August Environmental, 2001-02, private client).

Surface water and drinking water supplies

- Participating author for a source water protection plan and implementing an ongoing source water protection program to protect drinking water intakes from contamination and to respond effectively if contamination should occur. Specific responsibility for evaluation of real-time monitoring technology and implementation of early warning contaminant detection system (Downstream Strategies, 2014-present, for Morgantown Utility Board).

- Evaluated dye testing protocol, reviewed dilution calculations, and provided technical assistance to select trace dye chemicals with lowest toxicity for a major public water supply utility in north central West Virginia. Approach resulted in mitigation of potential impacts from leak testing at a large chemical manufacturing waste treatment pond upstream of source water intakes (Downstream Strategies, 2014).
- Led the development and implementation of a watershed monitoring program to protect source water for a major utility in north central West Virginia (Downstream Strategies, 2014)
- Designed and implemented a tap water testing and assessment program to evaluate impacts to private residences and commercial clients from a chemical spill impacting the surface water source for a public drinking water supply to over 300,000 customers in central West Virginia. (Downstream Strategies, 2014)
- Prepared a pump test methodology to document maximum sustainable yield and water quality for a public water groundwater supply well prior to encroachment by a stone quarry operation (Downstream Strategies, 2013).

Solid waste management

- Prepared a technical report entitled “Comments on Proposed Changes to New Your State Solid Waste Regulations” supporting a non-profit agency’s public comments regarding revisions to Title 6 of the New York Code of Rules and Regulations (NYCRR) Part, 360, Solid Waste Management Facilities Regulations affecting management of unconventional drilling waste streams and facility environmental monitoring programs. (Earthworks, August 15, 2016).
- Prepared technical comments supporting a local solid waste authority public comment submittal regarding proposed changes to the West Virginia Solid Waste Management Rule affecting management of unconventional oil and gas drilling waste streams at municipal solid waste facilities (Wetzel County Solid Waste Authority, July 28, 2014.

Indoor air quality

- Conducted an indoor air quality assessment for quantification and delineation of airborne fungal particulates in a multi-story municipal building. (Downstream Strategies, 2024).
- Conducted an indoor air quality assessment and delineated microbial/fungal impacts resulting from plumbing system failure in a multi-story, mixed residential/commercial use building. Provided remedial specifications and protocols and objectives for restoration attainment demonstration. (Downstream Strategies, 2024).
- Designed and implemented an indoor air quality assessment program for an aerospace industrial production and office facility. Completed data analysis and summary report of findings and opinions. (Downstream Strategies, 2022).
- Led an indoor air and subsurface soil gas assessment pertaining to persistent vapor intrusion following remediation of a substantial release of residential home heating oil during commercial delivery. (Downstream Strategies, 2019).
- Led field investigations and provided litigation support for multiple residential structures impacted by municipal sewage intrusion events (Downstream Strategies, 2013-2014).
- Evaluated indoor air monitoring data for a commercial structure impacted by soil vapor intrusion from historical underground storage leakage (Downstream Strategies, 2013).
- Led an investigation using specialty assessment tools and methods to quantify microbial impacts from a storm related water intrusion event at a multi-unit health care facility in Pennsylvania (Downstream Strategies, 2012).
- Led collaborative remediation efforts to complete major renovation of commercial buildings adversely impacted by hazardous materials and/or biological agents (Cira and Associates Consulting LLC and Downstream Strategies, 2002-present, various private clients).
- Conducted indoor air quality monitoring program and forensic analysis for microbiological impacts relating to construction practices. Prepared technical report and graphic presentations in support of litigation proceedings (Cira and Associates Consulting LLC, 2011, private client).
- Participated in installation of sub-slab vapor recovery system to mitigate vapor intrusion to large commercial building functional interior spaces from subsurface chlorinated solvent groundwater contaminant plume (Cira and Associates Consulting LLC, 2010, private client).
- Conducted indoor air monitoring programs to evaluate potential impacts to interior from sub-surface vapor intrusion pathways (August Environmental, Inc. and Cira and Associates Consulting LLC, 2004-12, various private clients).
- Led development and implementation of Indoor Air Quality Program to expand scope of client services (August Environmental, 2002-04).

Agriculture and the environment

- Quantifying the environmental benefits of a poultry litter baling facility in the eastern panhandle of West Virginia (Downstream Strategies, 2012, for Blue Moon Fund).

Risk-based corrective actions and Voluntary Remediation

- Project manager and senior technical lead serving private commercial and municipal clients as a West Virginia Licensed Remediation Specialist (LRS) of record under state led risk-based Voluntary Remediation Program (Downstream Strategies, 2014-present, for National Salvage and Service Corporation; City of Thomas, West Virginia; Friends of the Cheat, West Virginia).

Environmental due diligence and brownfields

- Prepared Draft and Final Analysis of Brownfield Cleanup Alternative (ABCA) documents supporting U.S. EPA brownfield cleanup grant applications and cleanups completed utilizing U.S. EPA grand funding. (Downstream Strategies, 2015-current).
- Technical lead for Phase I and Phase II ESAs prepared for commercial and governmental clients (Downstream Strategies, 2015-current).
- Conducted multiple Phase I ESAs for real-estate transactions associated with establishment of Conservation Easements at various tracts located throughout West Virginia (West Virginia Land Trust, 2016-2021).
- Project lead and West Virginia Licensed Remediation Specialist providing technical assistance and overall program management to several West Virginia local governments and non-profit organizations supported by USEPA Brownfield Assessment and Cleanup Grants for Hazardous Substances. Completed and on-going tasks include multiple Phase I and Phase II Environmental Site Assessments, development of USEPA-approved Sampling and Analysis Plans and a Programmatic Quality Assurance Project Plans, analysis of brownfield cleanup alternatives, and reuse planning. (Downstream Strategies, 2015-current).
- Managed Phase I Environmental Assessment process for multiple properties in Pocahontas County, West Virginia for the West Virginia In Lieu Fee Stream and Wetland Mitigation Program in accordance with ASTM Practice E 1527-13.
- Led Phase I Environmental Site Assessment process for three contiguous properties totaling 260-acres contemplated for conservation easement along the New River in Greenbrier and Pocahontas Counties, WC (Downstream Strategies, 2013, National Committee for the New River).
- Managed or directed numerous environmental due diligence Phase I and Phase II environmental site assessments (ESA's) at industrial sites, brownfields, and other properties to assess environmental liabilities. Transactions have ranged from single sites to large-scale corporate transactions. This work has involved developing quantitative cost estimates for the areas of environmental concerns identified. (Downstream Strategies, 2013-present, August Environmental, Inc., and Cira and Associates Consulting, LLC, 2002-12, various private clients).

Science communication

- Prepared expert report and presented at Zoning Board Special Exception Hearing regarding air emissions from co-located unconventional gas well pads and multi-engine compressor station in Penn Township, PA. (Downstream Strategies, 2024).
- Lead and presented at multiple public involvement meetings supporting U.S. EPA brownfield cleanup grant applications. (Downstream Strategies, 2021-2024).
- Presenter/Guide for the West Virginia Department of Environmental Protection Advanced Leadership Training, Thomas, West Virginia, May 9, 2018.
- Speaker/Panel Discussion Leader, 2017 National Brownfields Conference "Rural Revitalization: From Deteriorating Coal Town to Hip Tourist Destination". December 5, 2017.
- Presenter/Guide for the West Virginia Department of Environmental Protection Emerging Leaders Field Trip, Thomas, West Virginia, August 18, 2016.
- Presentation to the Wetzel County Solid Waste Authority: "Review of Wetzel County Sanitary Landfill NPDES Permit", New Martinsville, WV, August 4, 2016.
- Invited participant, Tucker County West Virginia, Regional Planning for Small Communities Stakeholder Workshop, 2015.
- Invited presentation to the W.Va. Legislature Judiciary Committee (December 2014, Proposed Changes to the West Virginia Solid Waste Management Rule).

- Provided support for litigation pertaining to the fate and transport of groundwater contamination in karst geology. Provided deposition and technical support for litigation pertaining to off-site migration of volatile organic compounds and dissolved phase chlorinated solvents from an adjacent industrial facility. Prepared a detailed estimate of probably cost for additional site characterization of contaminant plume and various cost scenarios for remediation. (Downstream Strategies, 2014-2015, private client).
- Conducted technical review and prepared comments to a county solid waste management authority in northern West Virginia on proposed changes to the West Virginia Solid Waste Management Rule pertaining to management of oil and gas related drilling wastes in municipal landfills. (Wetzel County Solid Waste Authority, 2015).
- Multiple presentations to watershed groups communicating experiences with monitoring for potential impacts from oil and gas operations in West Virginia and Pennsylvania (Downstream Strategies, 2013-2014).
- Invited participant at United States Environmental Protection Agency (USEPA) Technical Workshop on Subsurface Modeling (Downstream Strategies, LLC, June 3, 2013, USEPA).
- Invited participant at United States Environmental Protection Agency (USEPA) Wastewater Treatment and Related Modeling Technical Workshop (Downstream Strategies, LLC, April 18, 2013, USEPA).
- Invited participant at United States Environmental Protection Agency (USEPA) Well Construction/Operation and Subsurface Modeling Technical Workshop (Downstream Strategies, LLC, April 16-17, 2013, USEPA).
- Provided expert testimony in federal court regarding petroleum hydrocarbon contamination of soil and groundwater associated with natural gas development (Cira and Associates Consulting, 2011, for confidential client).
- Provided expert testimony in circuit court pertaining to heavy metals contamination and remediation (Cira and Associates Consulting, 2011, for confidential client).
- Presented complex information to a wide variety of stakeholders having diverse technical backgrounds and interests (Cira and Associates Consulting and Downstream Strategies, 2004-present, for various private clients).
- Worked closely with private clients, legal professionals, technical professionals, academia, regulatory officials, financial institutions, vendors, non-profit organizations (Cira and Associates Consulting, 2004-2012, various private clients).
- Presented to city council, zoning boards and public groups to attain cooperation from local government for large-scale petroleum remediation project (August Environmental, 2001-02).
- Prepared multi-media presentations for meetings with senior management, regulatory officials, and legal professionals (August Environmental, 2001-02).
- Compiled field data into graphical presentations as soil boring logs, well construction diagrams and detailed site figures (August Environmental, 1999-2001).

Project management

- Principal of environmental consulting firm Downstream Strategies, LLC and lead of the environmental monitoring and remediation services. Responsible for daily operations, human resource management, marketing programs, standard operating procedures, profit center and overall program management. Specific duties included client development, crafting of contract documents, budget tracking, establishing project milestones and timelines, and evaluating contractor performance with direct charge of final outcomes (Downstream Strategies, LLC, 2012-present).
- Founding/Managing partner for private environmental consulting firm. Responsible for daily operations, human resource management, profit center and overall program management. Specific duties included client development, crafting of contract documents, budget tracking, establishing project milestones and timelines, and evaluating contractor performance with direct charge of final outcomes (Cira and Associates Consulting, 2004-12).
- Managed more than 200 environmental cleanup projects involving petroleum distribution facilities, industrial and manufacturing facilities, commercial and residential buildings, and hazardous waste sites (August Environmental, Inc. and Cira and Associates Consulting, Downstream Strategies, LLC, 2002-present, for various private clients; federal, state, and local governments: and non-profit organizations).
- Directed collaborative efforts involving geologists, scientists, engineers, and specialists having diverse technical backgrounds to attain regulatory compliance under multiple regulatory frameworks.
- Provided technical supervision for hydrogeologic investigations, feasibility studies, remedial actions and numerous permitting and compliance projects.

- Developed and implemented project programs, provided technical direction to obtain optimal program/project outcomes, established technical milestones, reviewed and evaluated accomplishments, performed risk assessment and mitigation plans, crafted technical documents/presentations, and performed technical cost/benefit evaluations (August Environmental, 2002-04).
- Cultivated training protocols and operating procedures with primary responsibility for technical oversight (August Environmental, 2002-04).
- Coordinated teams of scientists and field technicians during remedial equipment installations. Directed staff through permitting and site work phases to fully operational contaminant recovery systems. Coordinated connection to electric utility services, including new service installations, and supervised teams of electricians during installation of transformers, high-capacity electric motors, and programmable logic control circuits (August Environmental, 2002-04).
- Developed pro-active task/project management style and established highly productive working relationships with new clients (August Environmental, 2001-02).
- Prepared project bid documents, scope of work proposals, and budget tracking summaries; maintained schedules for compliance reporting (August Environmental, 2001-02).
- Planned and assigned task orders and supervised field staff during site characterization activities for various soil and groundwater contamination sites (August Environmental, 2001-02).
- Mentored new hires and summer interns (August Environmental, 2001-02).

Certifications / Memberships

Certifications

- West Virginia Department of Environmental Protection Licensed Remediation Specialist #175, 2004-present.
- West Virginia Department of Environmental Protection Certified Monitoring Well Driller #WV00702, 2024-present.
- Certified Indoor Environmentalist – ACAC, 2006-present.
- Certified Mold Remediator – ACAC, 2004-present.
- West Virginia Certified Asbestos Contractor/Supervisor, 2003-2012.
- 40-Hour OSHA Hazardous Waste Operations and Emergency Response Training, 2000.
- 8-Hour OSHA Refresher Training, (annual) current.

Member

- West Virginia Chapter of the Air & Waste Management Association, 2013-present
- Pennsylvania Council of Professional Geologists, 2012-present.
- National Groundwater Association, 2010-present.
- Environmental Information Association, 2009-present.

Training completed

- West Virginia Department of Environmental Protection. Licensed Remediation Specialist Annual Training 2024, April 11, 2024. Groundwater Modeling, Natural Attenuation, Lead Risk Assessment. Attained 6.0 professional development hours.
- West Virginia Department of Environmental Protection. Licensed Remediation Specialist Annual Training 2024, December 20, 2023. Attained 1.0 professional development hour.
- West Virginia Department of Environmental Protection. Voluntary Remediation Program LRS Training, September 12, 2023. Attained 10.5 professional development hours.
- West Virginia Department of Environmental Protection. Licensed Remediation Specialist Annual Training 2022-2023, December 19, 2022. Attained 1.0 professional development hour.
- West Virginia Department of Environmental Protection. Licensed Remediation Specialist Annual Training 2022, December 15, 2022. Attained 1.0 professional development hour.
- West Virginia Department of Environmental Protection. Voluntary Remediation Program LRS Training, September 13-14, 2022. Attained 10.5 professional development hours.
- West Virginia Department of Environmental Protection. Voluntary Remediation Program LRS Training, September 14-15, 2021. Attained 2.25 professional development hours.

- West Virginia Department of Environmental Protection. Licensed Remediation Specialist Annual Training 2020-2021, December 15, 2020. Attained 1.0 professional development hour.
- West Virginia Department of Environmental Protection. Voluntary Remediation Program LRS Training, February 27, 2020. Attained 5 professional development hours.
- West Virginia Brownfields Conference, completed LRS Training Workshop sessions, "Voluntary Remediation Program Training for Licensed Remediation Specialists", September 11-12, 2019.
- West Virginia Brownfields Conference, completed LRS Training Workshop sessions, "Voluntary Remediation Program Training for Licensed Remediation Specialists", September 5, 2018.
- West Virginia Brownfields Conference, completed LRS Training Workshop sessions, "An Overview: The New West Virginia VRP Guidance Manual", September 2, 2017.
- Test America On-line Educational Programs "A Review of Lead Sampling, Analytical and Data". October 24, 2017.
- Professional Training Associates, Inc. "Lead Inspector Initial Training Course" and successful completion of examination for accreditation. July 14,17, and 19, 2017.
- Interstate Technology and Regulatory Council, CLU-IN seminar "Petroleum Vapor Intrusion: Fundamentals of Screening, Investigation, and Management", October 20, 2017.
- Hazardous Waste Operations Emergency Response "HAZWOPER" 8-hou Refresher Training in accordance with 29 CFR 1910.120(e), January 2017.
- West Virginia Brownfields Conference, completed 2 Continuing Education Credit sessions, "Treatment of Light, Non-aqueous Phase Liquids" and "Groundwater Treatment: Fate and Transport Modeling, Vapor Mitigation, and use of Liquid Activated Carbon", September 7 & 8, 2016.
- Hazardous Waste Operations Emergency Response "HAZWOPER" 8-hou Refresher Training in accordance with 29 CFR 1910.120(e), January 2016.
- West Virginia Brownfields Conference, completed 2 Continuing Education Credit sessions, "VRP Case Studies, Off-site Contamination and Storage Tank Regulations" and "Ensuring Environmental Sampling Integrity", September 15 & 16, 2015.
- Pennsylvania Brownfields Conference attained 9 Professional Development Hours for participation in workshops and training sessions, 2015.
- Pennsylvania Council of Professional Geologists Basic Tools for Shale Exploration, 2014
- United States Environmental Protection Agency and West Virginia Department of Health & Human Resources: Source Water Contaminant Detection Training; Early Warning and Response, 2014
- West Virginia Department of Environmental Protection Licensed Remediation Specialist Workshop, 2013
- Pennsylvania Council of Professional Geologists Marcellus Shale Environmental Management, 2012
- Pennsylvania Council of Professional Geologists Soil and Groundwater Geochemistry Course, 2008.
- Advanced Indoor Environmental Quality, 2008.
- U.S. Micro-Solutions IDL Training Center Advanced Indoor Environmental Quality, 2005,2007,2009,2011.
- Waterloo DNAPLs in Fractured Geologic Media Course, 2006.
- ASTM Phase I and Phase II Environmental Site Assessment Process, 2005.
- West Virginia University, Advanced Contaminant Transport Hydrogeology, 2005.
- Princeton Groundwater Pollution and Hydrology Course, 2004.
- Princeton Groundwater Remediation Course, 2004.
- Pennsylvania Department of Environmental Protection Land Recycling Program Workshop, 2004.
- Occupational Safety and Health Administration 40-hour Hazardous Waste Operations (OSHA 1910.120)/8 hr. Refresher, 2004/current.
- Appalachian Underground Corrosion Short Course, 2003.
- Cathodic Protection Technician – NACE, 2003.
- Cathodic Protection Course – Marcel Moreau Associates, 2002.
- Occupational Safety and Health Administration 8-Hour Hazardous Waste Operations, current.

Public Service

- National Interscholastic Cycling League Level I Coach/Mentor, 2023-present.
- Board of Parks and Recreation of City of Westover, 2006-present. President, 2006-12.
- Board of Directors of Canaan Valley Institute, 2016-present.
- Board of Zoning Appeals City of Westover, 2019-present.

- Morgantown Monongalia Metropolitan Planning Organization Citizens Advisory Committee. 2020-2021.
- Morgantown Monongalia Metropolitan Planning Organization Bicycle and Ped. Steering Committee, 2018-2019.
- West Virginia Mountain Bike Association, 1991-present.

Exhibit 14.06

This exhibit was not previously submitted in November 2023

October 15, 2024

Via ***rulescoordinator@rrc.texas.gov***

Rules Coordinator
Railroad Commission of Texas
Office of General Counsel
P.O. Drawer 12967
Austin, TX 78711-2967

Re: Additional Comments from Community Members on Proposed Amendments to Statewide Rules 8 and Subchapter B

In addition to Commission Shift's main comments, submitted concurrently today, Commission Shift collected comments from community members and those who participated in a visibility event outside the Railroad Commission offices in Austin. Many we encountered on the topic of waste pits felt defeated, disillusioned, and frustrated. The following community members have included some of their concerns below: Geoffrey Reeder, Paul Baumann, Lucas Jasso, Sister Elizabeth Riebschlaeger, Michelle Baumann, and Ron Pilsner.

"I don't have anything good to say about the new waste rules other than they are different from the previous rules. Different does not necessarily mean better. Either way the Texas rules are still more lenient than the Louisiana rules."Geoffrey Reeder, August 23, 2024

"My granddaughter was failing school because the noise and the smell from the waste facility were so bad. When TCEQ came out they couldn't smell it. I still live near the facility and I can smell it. My kids sold the land that had been in our family for over 100 years because of the nuisance and because there was no resolution from the Railroad Commission or the TCEQ."
- Paul Baumann, Nordheim, TX August 29, 2024

Lucas Jasso from Corpus Christi came to the October 18 Railroad Commission meeting and tailgate, commenting on his experience with an abandoned waste pit near his fenceline: "I thought I heard a young calf stuck in the mud down below, and as careful as I was on the edge of the berm, I slipped and got stuck in the mud. What was I going to do? Alone with no one nearby, I was in panic mode – squirming, wiggling, and digging in the mound, worried about how I was going to free myself. " He wondered whether the Railroad Commission would require operators to report on harmful chemicals in oilfield waste like arsenic, benzene and toluene. "I have a negative feeling trying to picture the storage and disposal of drilling fluids, wellbore materials, produced water, fracking flowback, concentrated salts, and toxic materials to an open air waste pit." After sharing these comments with commissioners, Lucas Jasso said he felt that the Commissioners were already resolved not to hear him before he began. They did not ask any questions after his input.

Sister Elizabeth Riebschlaeger also attended the October 15 Open Meeting and Tailgate, speaking on behalf of the Nordheim Community who has fought waste facility permits and impacts from existing sites. She was appalled that commissioners did not respectfully address those who came to give public input - "we are paying them with our tax dollars." She noted that it seemed even in their demeanor that they didn't care what community members had to say.

Michelle Baumann, Oct 11, 2024

My experience since I've lived in Nordheim Texas, has been exhausting in terms of the waste pits on Hohn Road.
I used to love walking out on Remmers Road alongside our property and other ranches.Now, not so much, especially
the last three to four months.

From Farm Road 237 one can see that the disposal site is expanding at a meteoric rate! There are many beeps and noises
constantly coming from the facility. I can hear the noise from our home on Remmers Road. But besides that, perhaps more disturbing
and distressing is the putrid smell that permeates the air,particularly when the wind is blowing from the North.

I no longer look forward to taking our German Shepherd for walks along Remmers, and I feel like no one really cares about our plight.
This has caused me headaches, and sleepless nights worrying about the expansion of this site, and what it will eventually do to our groundwater
here in Nordheim.

As Texas gets closer to adopting revised oil and gas waste management rules, I for one support more stringent measures.

The Hohn Road Disposal Facility manages toxic waste from dozens of drillers. The trucks hauling this material are more regulated than the actual facility.If they spill a small amount on the
road, they close down the entire highway until it is cleaned up!

These waste products fall under the rule include drilling mud, sludge, cuttings and produced water, and should be monitored more closely.Are they not more toxic as they grow in size and in one location? If the water seeps into our water supply, the ranchers and farmers, and the entire community of Nordheim will be adversely affected.

Please note the following article: "In Texas, waste pits have been linked to at least six cases of groundwater contamination and hundreds of violations of state rules." Texas waste disposal site under fire in Texas over possible ground water contamination - Search (bing.com)

We must look more closely at this specific site as I believe they are expanding too rapidly and don't have enough oversite.Last year, after a particularly hard rain, the berm at the Hohn Road Facility gave way ,and the runoff spilled onto a local rancher's property. The berms they built were inadequate for hard rainfall, and the runoff spilled out all over the land surrounding the facility.

Please note that I have filed several complaints with TCEQ , and as of 10/11/2024 there will be a field supervisor here at our property on Remmers Road to investigate the facts from my last written complaint.

Please use these comments , and any future comments I give regarding this matter.

Sincerely,

Michelle Baumann
957 Remmers Road
Nordheim, Texas 78141
361-491-1578

Ron Pilsner of the Nordheim community also wanted to reiterate his comments from the informal comment period and have Railroad Commission staff respond to the points therein. See https://www.rrc.texas.gov/media/b12b1frc/comments-ch4-informal-draft-nordheimcap.pdf

TO: Rules Coordinator/Changes to Subchapter A (Rule 8), Texas Railroad Commission

COMMENTS FROM NORDHEIM/CAP (Citizens Against Pollution)

DATE: November 1, 2023

Referenced: Petrowaste Solid Waste Facility, Hohn Rd. Nordheim, TX/Dewitt County

Permit No. STF-062 (TRANSFERRED/AMENDED); Associated Permits LT-0343, PO 1119994, PO 111995, PO 11996, PO11997, PO 11998A, PO 11998B, PO11998C, PO11998D PO11998E and PO111998F

RE: Changes to Subchapter A (Rule 8)

Part I

INTRODUCTION AND BACKGROUND FOR THESE COMMENTS: This background is provided as the basis for our later comments on the changes to Rule 8 being proposed by the TRC. Some of the proposed changes relate directly to our experiences of the Petrowaste site choice, design and operations.

A. These comments on the changes are the result of discussions of these changes among lifelong citizens of Nordheim and Dewitt County; some qualify as legal stakeholders. **All bring to this discussion and response their shared community experience, including concerns about the site before, during and after the Permitting process.**

- **Knowledge of the local topography, drainage patterns, history of stormwater** and flooding events on and around the site
- **Experience in working with the inferior material** to be used to construct the berms on the site.
- **Experience and knowledge of toxic substances** in some members whose work history includes supervisory positions in chemical plants and refineries;
- **Experiences of the Oct. 19, 1998 500-year Flood Event** along the Guadalupe and San Antonio River drainage areas and creeks in Dewitt and Karnes Counties.
- **Experience of the subsequent remapping of Flood Plains by FEMA** working with other authorities
- **Awareness of current official scientific predictions of future increases in rainfall amounts** due to Climate Change, i.e. stronger tropical storms and hurricane remnants passing through the area, increasing stormwater runoff (both contact and non-contact) on site. Subsequent changes in the plans were negotiated through the 3-year Protest Process and associated lawsuit.

B. **The original major concerns re stormwater retention on site were:**

- **Capacity for stormwater storage** on site (TRC agreed and required increased capacity)
- **Insufficient strength of the materials** to be used in construction of the berms: the excavated materials acquired from digging the pits for waste storage.
- **Angle of the hill** on which the site is located, since in the past, previous terracing had been constructed to retain soil in heavy rains

C. **Other community concerns were:**

- **the size of the site** (equal to the entire town of Nordheim)
- **volume of waste** that it is intended to process and store
- **proximity of the site** to the residents of Nordheim, including the school children:
- **Potential for noise, diesel emissions, dust and light pollution**

- **Potential for residents' exposure to toxic emissions (BTEX)** being aerated from the solid waste, drifting into town
- **Potential for aquifer and water well contamination** from tears in the liner and leaks
- **Placement of double liners with monitors and monitor wells** on site would be properly placed to detect leaks and potential for water contamination.

These concerns of the residents before the Permit was approved have been well justified during its years in operation.

D. **The following violations and incidents that have occurred since this site began operations.** They bear witness to the fact that strict requirements in the design and specific regulations and enforcement during operations are necessary for such a site.

- **Noise heard in town, day and night, depending on rig operations,** even by persons living at the point in Nordheim farthest from the site. (Two children of one family required counseling due to sleep loss and impacted academic performance due to lack of sleep from operations.)
- **Lack of security of the site.** (On one occasion, a herd of cattle somehow left their adjacent pasture, crossed through the site of operations, out the entrance of the site and wandered down the road into another private pasture.)
- **Light pollution** for those living around the site
- **Dust leaving the site** and blowing onto private property nearby
- **Toxic emissions detected by foul odors drifting onto farms and into town,** including onto the school campus and into private homes, depending on wind direction.
- **Mud and solid waste from the site being left on Hohn Rd**. as trucks exit the site
- **Road spills being shoved off the road and into the bar ditch** and dry creek bed leading to a stock tank
- **Berm materials eroding and being washed onto a private pasture** across from the site
- **Failure to maintain the berm by planting vegetation**, as directed;
- Exposure of the liners through large gaps in the eroded berm
- **Collapse of a berm supporting one wall of the non-contact stormwater retention pond after heavy rains, causing all the contents of the pond to run out, washing berm materials off the property to fill the bar ditches on either side of the road, and into a private pasture.** The force of the water flow tore down the chain link fence of the Petrowaste site, allowing free entry onto the site for wildlife and anyone who wanted to enter the site. The stormwater drained off the site, across the road, and across the private pasture into a creek about ½ mile away. It took 24-36 hours for the pond to completely empty. This incident confirmed the objections to the use of excavated materials to construct the berms. The material did not prove to be up to the strength needed, as the residents had warned during the Protest Process. But TRC officials did not listen to **local citizens, some of whom were stakeholders.**
- **The original entrance to the site proved to be hazardous both for commercial haulers and local drivers passing the site.** The entrance was of smooth concrete and at a steep angle. Dirt and waste materials ran down it when it rained, making the entrance slick so that trucks had difficulty entering and leaving the site safely. **During the process for Permit Renewal, the TRC required Petrowaste to move and redesign the entrance site, resolving the problems.**

CONCLUSION OF INTRODUCTION: It is clear that too many owners and operators in the oil and gas industry are concerned primarily with one purpose: to process and store as much waste as possible and to cut operations costs as much as possible in order to maximize profits. To them, Public Health and Safety are only secondary concerns. Therefore, in many cases, if a company is not closely monitored, they will cut corners, violate regulations and in general, take chances and display social irresponsibility toward the communities where they are located.

Any changes in Rule 8 regulations for design, construction and operation of all sites should require more, not less of them.

In fact, below, we are suggesting some changes of our own, to assure greater protection of our water, and of public health and safety when a solid oilfield waste facility moves into proximity of our homes, businesses, educational, health care and elder care facilities. Those socially responsible and conscientious operators will not object to regulations that help them protect Public Health and Safety, because they are probably now using best practices as their standard. **But other operators who put profit over human quality of life values will complain and object. These are the entities for whom regulations must continue to exist and be enforced rigorously.**

Part II

CAP'S FORMAL COMMENTS ON TRC'S PROPOSED CHANGES IN RULE 8 AND OUR PROPOSALS FOR IMPROVED REGULATION OF THE SOLID WASTE TREATMENT AND STORAGE SITE:

A. **On TRC proposed changes to Rule 8/Operations needing Permits:**

1. **Setbacks (cf. 4.150 (g) (h): We believe that setbacks should take into consideration not only the presence of surface water and groundwater, but also the potential for movement of toxic emissions off site and into populated areas.** That is because, while a setback may be thought sufficient to protect nearby surface waters, it may not assure a sufficient distance from human or animal life to protect them from toxic emissions moving into their private or commercial spaces. If water is groundwater is contaminated and rendered non-potable, bottled water can be used. And there may be remediation procedures to clean up contaminated ground water. **But people must breathe the air around them and when contaminated, they must wear breathing apparatus to protect their health or be told to shelter in place.**

   Therefore, any setback distances should be set with protecting both water and air quality protections in mind. A certain distance may be sufficient to protect surface water, but not enough to protect safe air quality. Both water and air safety considerations should be made in collaborative decision-making between the TRC and the TCEQ.

   Our recommendation is based on Nordheim's experience of having toxic emissions/odors traveling off site onto school property and into private homes one mile from the site. Also, operations at a distance of one mile from the farthest home in town has still not been enough to disallow noise and light pollution also to invade the peace of the community.

   This history makes clear to us that **a setback of 300 or even 500 feet is woefully insufficient. We are convinced that to be truly effective, any setback from surface water as well as for air quality's sake must be at least 2 miles and prefer 5 miles.**

   The peace and public health of any community requires also, that they be protected from noise and light pollution, and dust raised by truck traffic and site operations that will invade the peace or threaten the public health of the community. **Allowing any site close enough to disturb the peace is allowing the corporation's invasion of private lives and homes.**

2. **Section 4.114 (h): Less groundwater monitoring for authorized pits.** We do not support reducing the number of monitors. The changes of liner leaks that will contaminate groundwater and private water wells are too great, making monitors critical for their protections. We understand that industry's primary objective is commercial profit, and that involves eliminating costs. It is understandable that they want to cut back on these monitor

wells. However, it would seem that operators and owners of these facilities would realize that these monitors also protect them, because it will enable them to address any signs of contamination sooner. This would be to their own advantage as their financial liability might be diminished.

While good business management is always a good thing, it should also be socially responsible. Given that currently, there are critical issues associated with potable groundwater availability for private, commercial and municipal purposes, it is a major priority that water quality be maintained. Population increases and new industries needs are creating demands that are proving to be a challenge. At the same time, Climate Change is making water less abundant. Longer and more frequent drought periods are predicted by climatologists.

Aquifers are at risk, and some are depleted to the critical stage (e.g. the Ogalalla Aquifer that is the principal water source from New Mexico to Kansas.) Everyone, especially the solid waste management industry must make protection of water one of their primary objectives. This is no time for them to become less responsible.

Waste Pits and the risks they pose for groundwater are a major concern for anyone who appreciates the importance of aquifers and water wells. Therefore, this is no time to ask for fewer monitor wells on these sites.

3. **Sec. 4.111 (e) (f) Pit liners and burial-in-place. (Authorized Pits/no Permits Needed) We are against any liners being buried in place, including on production sites.** There is no guarantee that in the future, buried liners with waste may tear or deteriorate, allowing the waste to enter groundwater sources. For this reason, some ranchers have included in their leases that open lined pits for flowback not be used, but rather flowback stored in roll-off tanks. They also included in their leases that no liners be buried on site, even when they are allowed during the drilling and fracking phases. But this was because of their leases. **We ask the TRC to consider mandating these procedures for handling waste at drill sites as part of the Rule. We also ask that the TRC mandate double liners with sensors installed between the layers for earlier detection, making them standard for all solid waste sites.**

4. **"Commercial" vs. "private" designation. [4.111 (21); /Div. 5 and 10 (4.197 (a)]**

   The distinction between "private" and "commercial" facilities seem to be a moot point. Regulations for both should be set by requirements for safe air, water and preventing noise and air pollution. Both facilities should be bound by the same standards because both are handling the same waste.

5. **[Section 4.140(b)] New facilities Permitting, regardless of "statement of need". Given the problematic nature of these facilities for communities and the threat they have proven to be to environmental, public health and safety, we object to the permitting of any new facilities without requiring proof of need.** Too many individuals and companies are eager to build and operate these facilities for the purpose of profit.

6. **[Section 4.153(a)(1)] Flood Plain considerations: We do not support the proposed changes in the required documentation, i.e. that "less guidance" be given for considering the flood history of a site.** More guidance, not less, is needed now.

   Complete historic documentation is critical even more so in current changing conditions. If eliminated, this would allow an applicant to avoid realistic considerations of possible flooding of a site, and to ignore the possibilities at the moment, but taking a chance in order to obtain a Permit. **In fact, not only should past floodplain history be considered, but scientific projections by credible, certified entities re: increased potential for future flooding due to Global Warming should also be a required.**

Example of disastrous miscalculation: In Seguin, TX during the Oct. 1998 Flood, we saw what can happen when the flood potential was dismissed by failure to consider the history of flooding. As one lifelong resident stated after the disaster: "Everyone knew that this area always floods. We were surprised when we saw them building a new subdivision in that area." ***The site was approved and a Building Permit awarded for a new suburb, only to have every home in that suburb reduced to a clean concrete slab during the historic flood of Oct. 1998.***

The same miscalculation or dismissal of important flood history will most likely result in having a major flood wash out toxic hazardous waste onto downstream properties or into a creek, river or stock tank. That would be an even worse disaster than washing away a complete housing development—a disaster of the TRC's making by its failure to protect private property, ground and surface waters.

Two new considerations must be included in decisions about these rule changes:

- **FEMA created new Flood Plain maps for Dewitt County as a result of the October 1998 500-year flood. All regulations must be made with these in mind. Distances become even more important.**
- **Ongoing Climate Change impacts are predicted to increase in the decades ahead: record high temperatures, warming of the Gulf of Mexico, increasing rate of evaporation resulting from this rise and therefore, greater amounts of rainfall from tropical storms and hurricanes with their inland remnants frequently crossing into shale production areas where these waste pits exist.**

7. **Section 4.109. Exemptions to many rules without guaranteeing public review. Any proposal or request for a permit that may involve impact to any aspect of the Public Good must always involve a period of public input. It is not the role of the TRC nor of the Applicant for a Permit, to determine what does or not involve the Public Good. That is for the Public and their local officials to determine from their viewpoint. <u>The value of the Public Good and the Public comment mechanisms for defending and promoting it are a foundational element in any democracy</u>. It is unthinkable (but also typical of the current industry and legislative trends) that it be simply eliminated to the advantage of industry and commercial interests.**

8. **Secton 4.193 (b). RE: Haulers records of destinations. The proposal that haulers no longer identify on their applications each facility it will be working with creates a loophole for haulers to dispose of its waste in an unapproved manner. If, for some reason, a hauler needs to change their destination to another, the Application info can be edited or updated.**

   All oilfield waste, liquid or solid is hazardous, and no exceptions to any Hazmat Rule changes the facts of waste chemistry, even if by that exception, solid hazardous waste is no longer handled as hazardous waste.

   It is critical, therefore, that all waste be properly identified, tracked and disposed of at the proper, legal sites. If a driver does not have to specify a destination, there is no way to

track where that waste is being or has been taken for disposal. Often, drivers are not fully aware of the toxicity to human health and the environment of their loads. Removing this tracking requirement many create the possibility that they develop a dangerously casual disposition toward how and where they choose to dispose of their loads.

In addition, for the TRC to exempt a hauler from this requirement is to put the Commission in direct conflict with the Oil and Gas Waste Haulers Act (Tex. Water Code $29.013), which requires such an affidavit.

9. Section 4.193(e). This removes the need for a hauler to carry the above paperwork. This is contrary to best practices for all of the above reasons. The only justification for removal of this paperwork requirement would be that the equivalent record is maintained by the hauler in an electronic program.

SUMMARY OF THE NORDHEIM CAP GROUP'S RECOMMENDATIONS BASED ON OUR EXPERIENCE OF A SOLID WASTE TREATMENT AND STORAGE FACILITY IN OUR COMMUNITY:

1. **Setbacks.** Any setback distances should be set with protecting **both water and air quality** protections in mind. A certain distance may be sufficient to protect surface water, but not enough to protect safe air quality. **Both water and air safety considerations should be made in collaborative decision-making between the TRC and the TCEQ.**

   Since a distance of one mile from Nordheim's western most city limit has not been sufficient to keep odors/toxic emissions, noise and light nuisances from invading our privacy in town, we believe that the recommended setback distances (from 300 to 500 feet) are not sufficient.

   We recommend that such facilities be at least 2 to 5 miles from any home, business or community as well as at least on mile from any surface water such as creeks, rivers, stock tanks, lakes or reservoirs.

2. **Site construction: Initial design, especially with regard to increased capacity for stormwater retention on site and materials used to construct berms.**
   a. **There is a need for increased capacity for retention of storm water, especially contact water. If the capacity for storage is not increased by taking the predictions for increased rainfall amounts in mind, current capacity requirements (for both contact and non-contact retention ponds) will not be sufficient. Overflows will be a man-made contamination disaster endangering human, livestock and wildlife, risking surface water contamination and damaging other agricultural resources. Such spills and overflows, especially of contact water, require expensive cleanup. "An ounce of prevention is worth a pound of cure." (Benjamin Franklin)**
   b. **It will also require strict standards for assuring that berm materials will be of sufficient strength so that berms do not collapse, as happened at the Nordheim facility. More specific requirements or oversight of the makeup of materials to be used should be established. Strengthening of berms is needed, as well as making sure the Operator is in compliance with all Permit requirements, e.g. assuring that vegetation or other methods are sufficient to prevent erosion of berms.**
   c. **Another consideration should be the plane or lay of the land at the site under consideration. Any facility of this kind that is located on a hillside defies the law of gravity. This makes runoff and berm collapse potential even more possible. There should a clear description of the surface topography that is suitable for such a site, indicated by the angle of the plane of any hill at the location upon which the facility is to be built.**

3. Solid Oilfield Waste Treatment Facility Technology. We believe that the current design of such sites is outdated, that more efficient and safer technology already exists and should become the new industry standard. Current "pit filling processes" should be ended.

   In fact, a newer disposal technology does exist and has been in successful operation. It employs the use of a centrifuge to remove the liquid waste from the solids brought in to the site, transporting the liquid waste to an injection well site and use of a double incineration process to burn the remaining solid waste. The second incineration destroys the toxic emissions created by the first incineration. The result is no toxic emissions leaving the site. This process has been described by an air quality expert, as the best and most effective method for disposing of solid oilfield waste currently available.

   We call on the TRC to plan the phase-out of this older design that aerates toxic chemicals into the air, and to require adoption of a new design that has proven superior in design because of its high performance and its effectiveness in eliminating any possibility of either surface water, ground water and production of contaminated air emissions. We call for the adoption of this newer, more efficient and cleaner technology in future permitting as soon as possible.

4. Section 4.114 (h): We see monitor wells as a major factor protecting groundwater under these solid waste processing facilities, even if the industry devalues their worth. We believe that there should be more monitoring wells, specifically, monitor wells that are located off the site, above the downdip groundwater flow to assure that no contamination is coming from the site, in addition to the ones on site.

   Also, we propose that the results of groundwater monitors be reported every three months on a site's commercial webpage and also on the TCEQ's website, and that results be made available to stakeholders and the public.

End of Comments from CAP Members, Nordheim, Dewitt County, TX

Contact Person: Lyn Janssen, Hohn Rd. Nordheim, TX lynjanssen@att.net

361-564-6748 (cell)

Signatures of CAP Members participating in these discussions and submitting these Comments follow:

Signatures of CAP Members participating in these discussions and submitting these Comments:

Signature	Printed Name/Contact info
Paul Baumann CAP PRES.	PAUL BALMANN 951 Rummel RD Nordheim
Ruth Newman	Ruth Newman 1239 Bochle Rd Nordheim TX 78141
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DATE: 10·31·23

TO: Rules Coordinator/Changes to Rule 8/Texas Railroad Commission

rulescoordinator@rrc.texas.gov

Exhibit 16.01

This exhibit was not previously submitted in November 2023

November 3, 2023 (5 pm)

Via ***rulescoordinator@rrc.texas.gov***

Rules Coordinator
Railroad Commission of Texas
Office of General Counsel
P.O. Drawer 12967
Austin, TX 78711-2967

Re: Comments on Informal Draft Amendments to Statewide Rules 8, 57 and Subchapter B

Dear Rules Coordinator:

Commission Shift appreciates the opportunity to provide input on the Railroad Commission's informal draft Amendments to Statewide Rules 8, 57 and Subchapter B.

Commission Shift is a nonpartisan non-profit focused on reforming oil and gas oversight in Texas by building public support to hold the Railroad Commission of Texas accountable to its mission in a shifting energy landscape. We have met with community members affected by oil and gas waste pits and collected feedback relevant to these proposed amendments.

In line with these goals, Commission Shift respectfully submits the following comments. Commission Shift's comments suggest how the Railroad Commission's oversight of oil and gas waste pit operations could be improved by (1) allowing for actual meaningful public participation in this rule-making; (2) incorporating rules that better protect the public and environment during the permitting process and during operation of waste management units; and (3) strengthening the Commission's ability to reject bad applications and improving the Commission & public's ability to enforce against bad actors.

Note that these comments are divided into three parts. The first portion places the rule in context, highlighting community experience with the regulation of oil and gas waste management and providing historical background. The second part outlines overarching themes to Commission Shift's concerns. The third part provides specific, line-item comments on the proposed rules.

Commission Shift welcomes a dialogue with the Commission as any questions or concerns arise during the Commission's review of these comments, just as industry has been allowed to dialogue with the Commission for the past two years in the drafting of these rules. There is still opportunity for the Commission to allow for meaningful public participation in this process and to draft rules that address the human health and environmental concerns raised by Texans.

Sincerely,

[Virginia Palacios]

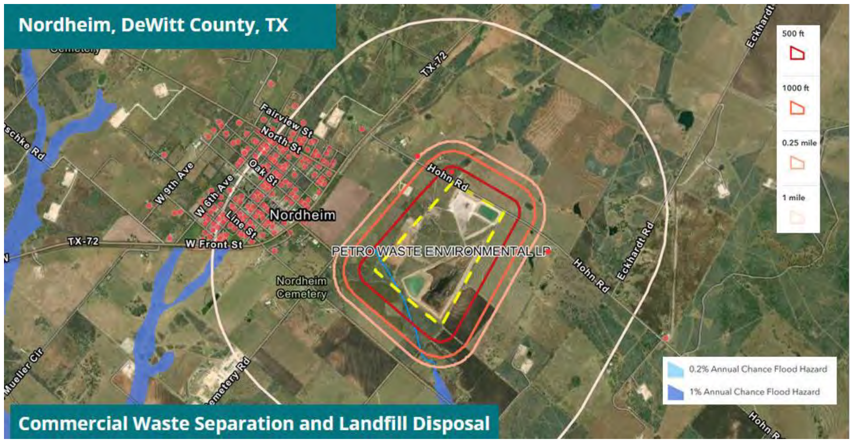
Enclosures

Table of Contents

PART I – CONTEXT & COMMUNITY EXPERIENCE WITH SWR 8 & CHAPTER B

1. Communities have been harmed by facilities regulated under the current rule and by lack of enforcement.

Texans across the state have struggled for years with how oil and gas waste operations are regulated under the current rules, and how the current rules are being enforced. Commission Shift has talked to many community members living near these operations and offers the following vignettes to give context to the proposed rulemaking.[1]



Petro Waste's Hohn Landfill Facility near Nordheim, TX (DeWitt County). Citizens of Norheim and DeWitt County have experienced firsthand how the Commission and Rule 8 has failed to keep polluting facilities from being permitted and operated in inappropriate locations.[2] Less than one mile outside of Nordheim lies Petro Waste Environmental LP.'s 140-acre+ Hohn Facility, a commercial waste separation and landfill disposal facility.[3]

To help the Commission visualize how close facilities like Hohn are to sensitive receptors like homes, water bodies, floodplains and water wells, Commission Shift has created maps of some of these facilities using publicly available data.[4] Reported residences are shown as red dots; many are

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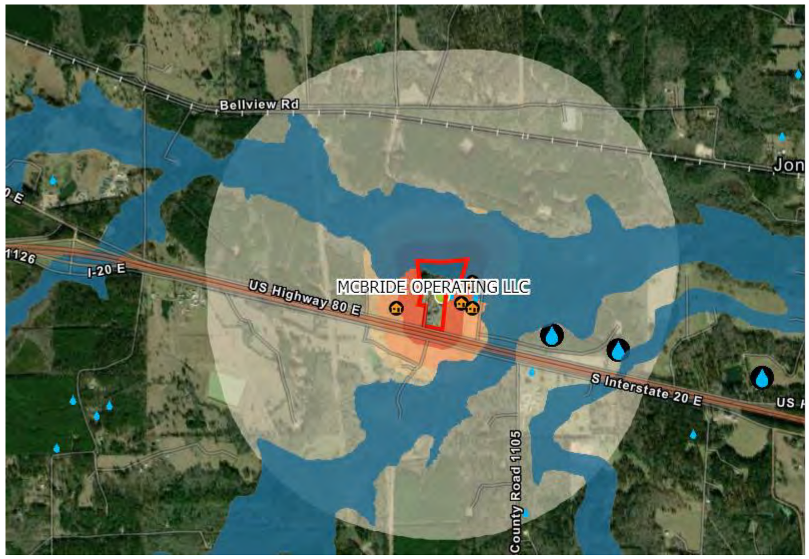
[1] Other stories include: Ex. 1 Fehling, Dave. How 'Landfarms' For Disposing Drilling Waste Are Causing Problems In Texas. NPR. (Nov. 12, 2012). https://stateimpact.npr.org/texas/2012/11/12/landfarms-for-disposing-drilling-waste-causing-problems-in-texas/

[2] The story of citizens' on-going struggles with the landfill near Nordheim has been documented in a number of news outlets. See e.g., Ex. 2 Tiny Nordheim Sues State Over Drilling Waste Dump (Texas Tribune) (August 2016) https://www.texastribune.org/2016/08/02/eagle-ford-tiny-nordheim-keeps-battling-drilling-w/; South Texas Drilling Country Saying No to Waste (October 2, 2013) https://www.nytimes.com/2014/10/03/us/south-texas-drilling-country-saying-no-to-waste.html; Ex. 3 Nordheim loses fight as Railroad Commission OKs oil field landfill. (May 3, 2016) https://www.mysanantonio.com/business/eagle-ford-energy/article/Nordheim-loses-fight-as-Railroad-Commission-OKs-7390449.php. Those struggles include: dealing with a permitting process that allows applicants to continue redesigning and amending their application even after it is declared administratively complete; and struggling to obtain adequate stormwater controls and air monitoring.

[3] Petro Waste Environmental Obtains Nordheim Landfill Permit (May 3, 2016) https://tailwatercapital.com/petro-waste-environmental-obtains-nordheim-landfill-permit/

[4] These and other maps can be found at https://commissionshift.org/our-work/cleaning-up-oil-gas/waste-pits/ Commission Shift notes that it makes no claims as to the accuracy of this data (though it has used publicly available sources, including the Commission's list of active waste sites) and these maps are not intended to make any claims about the accuracy of permitting or enforcement, but are intended to help the Commission put the facilities in context with nearby sensitive sites.

within one mile of the facility, some closer than 500 feet. Only surface owners within 500 feet of the property line would have received notice under the proposed rules—but as the complaints from this facility show, the facility's ill effects have been felt far beyond 500 feet. This is another reason that setbacks should be expanded from beyond what is proposed in the rules—500 ft from the permitted pit (not the property boundary)—is too little. Also included in this map is the 100-year floodplain, which appears to extend near one of the pits visible in the satellite image.



The McBride Waste Separation facility near Waskom, TX (Harrison County) is another example of how difficult living next to a waste facility can be with the way the current rules are implemented and enforced. Through Public Information Act requests, Commission Shift obtained numerous records detailing citizen complaints and operator violations for this facility. In just one example of troubling conditions from July 2023 (below), an inspection reported an unpermitted pit with off-the-chart readings of salinity (over 80,000 ppm).[5] (For context, the proposed rules would require such a pit to get a permit if its contents exceeds 3,000 ppm chloride (under the current rules, 80,000 ppm is also not allowed without a permit).) During that visit, trucks were observed actively unloading saltwater into the pit while fluids with a salinity of over 20,000 ppm had spilled out of the pit into the woods for a distance of 335 feet.[6]

Fluids inside the new unpermitted pit appears to be saltwater.

The salinity probe does not read extremely high readings of salinity.

In addition, on TCEQ's groundwater contamination map, the Waskom Waste Separation Facility is listed as facility with an active groundwater contamination case since 2021 (File number OCP#5237), with the contaminants described to include

[5] Ex. 4, McBride Waskom STF Facility RRC Inspection Reports (July) Figure – Snapshot of YSI salinity meter reading at McBride Waskom STF facility (2023). Note: meter shows "OVER" for salinity reading – upper limit for meter is 80 ppt or 80,000 ppm salinity (per YSI handheld salinity/conductivity/temp meter: Ex. 5 https://www.enviroequipment.com/product/ysi-30-conductivity-salinity-temperature-rental)

[6] As the inspection report describes it, "The brush limbs and vegetation on the spill path appears to be dea[d]."

benzene, TPH, and chloride.[7] This facility also appears to be located near many sensitive receptors. The map here shows that the 100-year floodplain seems to extend onsite, with homes located as close as 500 feet. At least two public supply wells (large blue droplets) appear to be located within a mile of the facility, and other wells (small blue droplets) even closer.

The same operator, McBride, has also forced the community of Paxton, TX to spend a small fortune fighting to convince the Commission that another proposed site is no place for a permanent landfill.[8] The site, which "has two ponds and a wetland . . . [and a] creek [that] originates there and then meanders into the Sabine River," is located some 500 yards from the town's wells, is on top of the Carrizo-Wilcox Aquifer, and is just upstream from multiple private drinking water wells.[9] Yet as the Texas Tribune reported, McBride's application for this facility keeps being revived:

> Permit applications [under Rule 8] are typically approved unless challenged by a third party, such as the residents of Paxton, who have found that threats to public health must reach a high bar to compete against economic interests for the commission's sympathies.
>
> When the commission met last December, its technical permitting division rejected the Paxton project's permit for the second time in four years over concerns about groundwater contamination. But Commissioner Jim Wright, a former rodeo cowboy and landfill developer, wasn't ready to let the project die.
>
> "I myself have constructed safe landfills in similar conditions," Wright told the meeting in the Texas Capitol. "It can be done."
>
> Instead of issuing a final rejection, Wright suggested the commission provide the developer, McBride Operating LLC, with a list of edits and additions to the application and invite them to resubmit. The commission had already asked the firm to amend its application at least four times since 2019.

Fighting this application has cost community members hundreds of thousands of dollars in legal and expert fees.[10] Community members are exhausted of being the ones who must protect Texas lands and waters from pollution, when they should be able to rely on the Commission. In conversation after conversation, Commission Shift has heard community members ask—will this rulemaking fix things? And unfortunately, based on the current draft, it does not appear so.

Blackhorn Environmental near Orange Grove, TX (Jim Wells County). Another site that highlights the importance of strengthening the human and environmental health protections in Rule 8

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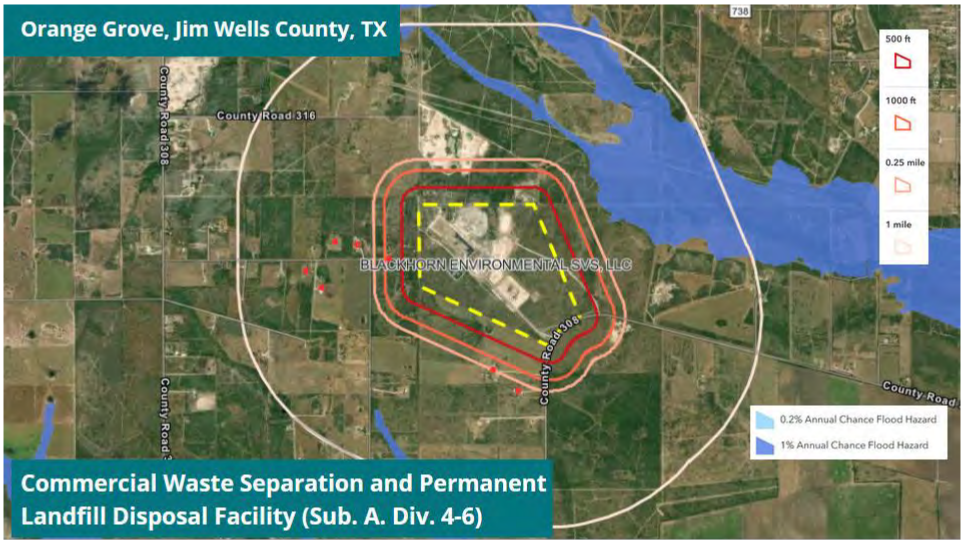
[7] TCEQ Groundwater Contamination Viewer (Accessed October 31, 2023). https://tceq.maps.arcgis.com/apps/webappviewer/index.html?id=5a36690f56bc4f128588b19b092cbf91 Commission Shift has not found this map hosted on the Commission's own site, but it should be. As early as 2000, STRONGER has recommended that similar such information be published to the Commission's website for abandoned sites as well. Ex. 6 STRONGER Texas Review (2000 Guidelines 6.7.1) (stating that the "RRC should release to the public, perhaps via its web page, a periodically updated list presenting the location, extent of contamination, and status of remediation of abandoned sites").

[8] Ex. 7 Baddour, Dylan. In East Texas, a town fights to keep an oilfield waste dump from opening near wetlands and water wells. (Jan. 30, 2023) (originally appeared in The Texas Tribune at https://www.texastribune.org/2023/01/30/east-texas-oilfield-dump-railroad-commission-paxton/).

[9] Id.

[10] Id.

is Blackhorn Environmental in Jim Wells County. The problems at this disposal site have generated extensive media coverage.[11] Community members of Orange Grove suffered health issues such as nausea and headaches following the construction of the Blackhorn Environmental Services facility. Members of the community attempted to bring concerns to the Commission regarding the facility, but the Commission decided to renew the permit anyway. Facilities like Blackhorn show why oil and gas waste facilities should be setback from sensitive receptors, with no exceptions allowed.



2. Communities have been shut out of the drafting process and denied anything resembling an equal seat at the table

Industry representatives and the Commission have been co-drafting these rules since at least 2022, but the general public, front-line communities, and community-minded groups like Commission Shift have been excluded from these meetings and discussions. In fact, Commission Shift explicitly asked in August 2023 to be included in any follow up meetings with the industry about the rule (and to be sent any additional drafts shared with industry); no invitations were forthcoming even though afterwards multiple meetings with industry were held and at least two other full drafts exchanged (one of Subchapter A and one of Subchapter B). Only through Public Information Act requests has Commission Shift been able to learn that before public comment opened, dozens of conversations occurred between Industry representatives and the Commission over the last two years. Meetings were held both in-person and virtually, in small and large groups, and at least eight drafts had been

[11] E.g. Ex. 8, Bradshaw, Robin. TCEQ investigates Blackhorn Environmental Services in Orange Grove. Alice Echo-News Journal. (December 7, 2020) https://www.caller.com/story/news/2020/12/02/tceq-investigates-blackhorn-environmental-services-orange-grove/3798642001/; Ex. 9 Buch, Jason. For Texans, Fighting State-Regulated Oilfield Waste Dumps Can Be a Costly, Do-It-Yourself Effort. Public Health Watch. (August 15, 2023) https://publichealthwatch.org/2023/08/15/texas-oilfield-waste-dumps-railroad-commission/

exchanged—four of Subchapter A and four of Subchapter B.[12] Industry and its representatives provided hundreds of pages of comments and many sessions of in-person feedback. Voices outside of industry were deliberately excluded.[13]

The public was finally allowed to participate in this rulemaking only through the informal public notice and public comment process that started October 1, 2023. However, the Commission's engagement of the public is minimal and only included one in-person meeting that was held in Austin far from any substantial oil and gas impacted communities and lasted about 30 minutes. The virtual meeting held the following day. Both public input meetings were offered during the work day and not in the evenings when the general public would be more likely to attend without missing work.

Conversely, in 2002—the last time major changes were contemplated to Rule 8—rule-making meetings were held throughout the state and input was received from a variety of stakeholders, not just industry.[14]

According to the 2022 STRONGER Guidelines for oil and gas regulations, an effective state program should include public participation as follows: [15]

> Where public input is sought, the agency should utilize communication methods that will most effectively reach affected communities. Effective communication should include creating short, plain-language summaries of proposed actions that are understandable by people with a variety of educational attainment and levels of English proficiency. **States should consider factors that may limit meaningful involvement of affected communities in public comment opportunities, such as non-English speaking populations, timing of meetings, and availability of internet access. When translation is required comment periods should be extended to allow adequate time for both translation and outreach to the population. States should interface with community groups in the affected community to inform and plan for translation needs.** States should also consider offering interpretation services for any hearings or public meetings about proposed permits or licenses, to make those meetings accessible to non-English speakers.

[12] Many of these drafts were shared as word documents, which are easy to edit, copy and add track changes or comments to. In contrast, the drafts published in October on the Commission's website for the public to review were pdfs. Pdfs are much harder to edit, copy from, and compare, especially without a commercial subscription (which the public does not typically have), and when converted to a word document tend to not recognize that line numbers are separate features than text.

[13] This was made clear throughout the process and explicitly acknowledged. Ex. 10 (2022 PIA Disclosure) "My instructions were to share with the associations, expecting the associations to selectively share with you and other consultants/lobbyists/members."

[14] The 2002 draft—which was similar in breadth to the current rulemaking but was ultimately was not adopted—was shaped by a series of workshops held for informal public comment, held in Midland, Wichita Falls, Houston, Kilgore, Austin, and Amarillo. "A total of 188 people attended, including 152 representing industry, six representing land and royalty owners, seven with groundwater conservation districts, and 23 who identified themselves as rep resenting 'other.'" 27 TexReg 4265. Comments were received from 120 persons, many who were not in attendance at the workshops. Id.

[15] STRONGER is an organization that publishes guidelines for state regulators as to the appropriate elements of a state oil and gas regulatory program. Ex. 11, 2022 STRONGER Guidelines at 26. For more background about STRONGER, see the History section of Commission Shift's comments.

> **The agency should consider methods to enhance the responsiveness of its public participation such as responding to comments and sharing how the program considered comments in its decision making**.

Language access is also an essential part of facilitating meaningful public participation and is in fact required under federal law for state agencies that receive federal funds.[16] In addition, the Commission, not Commission Shift, should be bearing the brunt of outreach to and engagement of community members, as the 2022 STRONGER Guidelines recommend:[17]

> States should use advisory groups of industry, government, and public representatives, or other similar mechanisms, to obtain input and feedback on the effectiveness of state programs for the regulation of E&P activities. Provision should be made for education or training as is appropriate to give such advisory groups a sound basis for providing input and feedback. **States should seek opportunities to partner with community groups to gather information on unique community needs and input. States should seek to foster positive relationships with such community groups to develop open lines of communication and improve the transparency and availability of data.** When community members serve on advisory groups in a purely volunteer capacity (i.e., are not paid by their employer for their participation), **states should explore providing stipends or participation incentives (i.e., gift cards) to compensate the community members for their time**.

The two hearings held on October 26 and 27, 2023 did little to encourage and cultivate meaningful public participation. The meetings were held in the morning and concluded well before noon rather than remaining open in case folks that could not take off work might find time to comment during their lunch break. In addition, the hearing officer's instructions were not translated although the Commission presentation was translated in Spanish. Commission staff's presentation overviewing the changes was extremely abbreviated and lasted less than ten minutes. Commission staff was not allowed to answer any questions that commentors and attendees might have had.

Oral comments at both the in-person and virtual public meetings was limited to 3 minutes per speaker even though very few people offered to speak and both meetings concluded in an hour or less. In fact, even operators commented that three minutes was not enough time to voice their concerns. The participants were only told they would be limited to three minutes at the meeting and not in advance. Recordings of the meetings were not made available to the public after the meetings concluded nor before the informal public comment deadline submittal.

The Commission clearly has failed to meaningfully engage the public in this rulemaking up until this point, despite ample opportunity to do so.[18]

[16] Specifically under Title VI of the Civil Rights Act of 1964.
[17] Ex. 11, 2022 STRONGER Guidelines at 27.
[18] Ex. 12 Commission Shift's August 2023 Handout of Recommendation for Public Participation. This was shared with Commission staff at the August meeting.

3. <u>The need for updates to Rule 8 is long-standing as Rule 8 has not been seriously revised in forty years.</u>

Statewide Rule 8 has been largely unchanged since 1983. Since that time the Commission has been failing to protect public health and the environment in front-line communities that have been subjected to pollution generated by oil and gas activities without consistent and meaningful public participation. To put this rule-making in context, Commission Shift provides the following abbreviated history of Rule 8, [19] including an aborted attempt to revise these rules in 2002:[20]

Prior to Rule 8. Rule 8 was first codified in 1976, but the Commission has been regulating pits since at least 1969, when it prohibited unauthorized use of saltwater disposal pits in a statewide order.[21] Piecemeal modifications to Rule 8 occurred in 1977 (regarding rules on salt-water hauling[22]); and in 1980 (regarding exemptions to the saltwater pit rule[23]).

Rule 8 is born. In 1983, major modifications were proposed, spurred in part by House Bill 2005, which was codified at TNRC Subchapter K (91.451 et seq). Supporters of the bill recognized the long-term threat of groundwater contamination, which could occur many years after the fact with the potential to render the water unusable "practically forever."[24] Those opposed were concerned that the bill wasn't strong enough.[25] Even then, those opposed recognized that plastic liners "almost invariably leak," and wanted liners to be made of a truly impervious material.[26] Opponents also wanted pit operators to post a bond that would be forfeited if the pits leaked saltwater into the ground.[27] In addition, opponents recognized that the Commission even then did not have a good record of enforcing pollution-control laws and rules.[28] The House Natural Resources Committee had concluded in an interim report that "the [C]ommission ha[d] been guilty of lax and selective enforcement in cases of water pollution by the oil and gas industry."[29] At the same time there was a push in the Senate to give concurrent enforcement authority to TPWD and the Department of Water Resources (precursor to the Texas Water Commission and the Texas Water Development Board). That effort failed.[30] But nonetheless, by 1984, the bulk of Rule 8 as it appears today was adopted.[31]

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[19] The commercial recycling rules found in Subchapter B have a shorter history, and were drafted largely in 2012.
[20] The Commission has acknowledged that the rewrite to Rule 8 is informed by the 2002 rule draft. Ex. 13 (PIA Request) (Cover Email).
[21] Committee Report on HB 2005, at 1 (May 6, 1983).
[22] 2 TexReg 359.
[23] 5 TexReg 3794.
[24] Committee Report on HB 2005, at 2.
[25] Id.
[26] Id.
[27] Id.
[28] Id. at 3.
[29] Id.
[30] 68th SB 895
[31] 9 TexReg 1549.

Minor amendments are made after 1984. More amendments were proposed in 1985, most to dovetail with the addition of another rule about discharge to waters of the state.[32] When that new rule fell through, only a few amendments were made, including reasserting the scope of an applicant's duty to identify and notify nearby landowners of an application and not merely through publication.[33]

In December 1986, the RRC clarified the scope of oil and gas activities that would trigger its jurisdiction, including under Rule 8, by largely tracking language passed by the Legislature.[34] In January 1992, amendments were adopted to comply with statutory requirements related to the funding of an Oilfield Cleanup fund.[35]

When the first Texas Coastal Management Plan (CMP) was adopted in 1994, changes to Rule 8 were required, largely in section (j).[36] Regulations for oil and gas waste haulers were updated again in 1994.[37]

Major changes to Rule 8 fail in 2002. In 1992, the RRC's programs were reviewed by stakeholders coordinated by the Interstate Oil and Gas Compact Commission (IOGCC) and funded by the EPA.[38] The Review Team's suggestions were published in 1993; some but not all were implemented by 2002.[39] Changes proposed to Subchapter B in 2002 would have addressed the remaining recommendations.[40] However, the proposal was officially withdrawn by the RRC on November 19, 2002,[41] and the push to seriously reform Rule 8 in 2002 failed.[42]

The 2002 draft had been shaped by a series of workshops held for informal public comment, held in Midland, Wichita Falls, Houston, Kilgore, Austin, and Amarillo. "A total of 188 people attended, including 152 representing industry, six representing land and royalty owners, seven with groundwater conservation districts, and 23 who identified themselves as representing 'other.'"[43] Comments were received from 120 persons, many who were not in attendance at the workshops.[44]

According to the RRC then (as now), the 2002 rule proposal was generally consistent with existing practices. The proposed changes specifically intended to: clarify and strengthen requirements for the prevention of pollution of surface and subsurface waters; conform to the

[32] 10 TexReg 3044 (Aug. 13, 1985).
[33] 11 TexReg 948-49.
[34] 11 TexReg 5092 (citing House Bill 2358, 69th Legislature, 1985).
[35] 17 TexReg 321-22 (clarifying preamble).
[36] See 20 TexReg 2578-81 (proposed rule); see also 20 TexReg 8442-45 (adopted rule).
[37] 20 TexReg 3529-32.
[38] 27 TexReg 4273. In 1999, the IOGCC created the State Review of Oil and Natural Gas Environmental Regulations, Inc. ("STRONGER") to revitalize and carry the state review program forward. STRONGER publishes guidelines for state regulators as to the appropriate elements of a state oil and gas regulatory program. Ex. 11 2022 STRONGER Guidelines at 7. https://www.strongerinc.org/wp-content/uploads/2022/07/2022-Edition-STRONGER-Guidelines.pdf
[39] Id.
[40] Id.
[41] Ex. 6 STRONGER Texas Review at 9 (pdf 15)
[42] See 27 TexReg 4264 (proposed rule).
[43] 27 TexReg 4265.
[44] Id.

wording of rules to reflect current practices cutting costs for industry (automatically transferring a non-commercial pit from one operator to another with a P-4 change of filing; lengthening the term of a minor permit from 30 days to 60 days; eliminating the need for a minor permit when the activity is licensed by another entity); incorporating guidance into the rules; and respond to recommendations that arose out of the 1992 IOGCC state review:

> For authorized pits, the Review Team Report included the following recommendations: (1) revise §3.8 to include requirements applicable to authorized pits based on specific geologic, topographic, hydrologic, or other conditions; (2) require prior notice of construction and use of authorized pits; (3) prohibit the use of unlined basic sediment pits for the disposal of oily wastes; (4) develop rules specifying site restrictions, prohibitions, construction notice requirements for the various types of authorized pits; and (5) amend §3.8 to define minimum construction standards for all rule-authorized pits, to include general operating standards for rule-authorized pits, and to add general pit closure standards for rule-authorized pits.
>
> For pit permits, the Review Team Report included the following recommendations: (1) amend §3.8 regulatory standards for permits to specify that: pit size should be sufficient to ensure adequate storage until closure, taking into account historical precipitation patterns; pit depth should be such that the bottom does not penetrate groundwater, or such that pit contents do not adversely impact groundwater or surface water; and berm height, slope, and material should be such that the pit is structurally sound, and that pit integrity is not compromised by terrain or breached by heavy rains, winds, seepage or other natural forces; (2) impose a fixed term limit on all individual pit permits; (3) amend §3.8 to include specifications for site restrictions for various types of permitted waste management facilities, to include general operating standards for permitted pits, and to add general pit closure standards for permitted pits.
>
> For land treatment and road spreading, the Review Team Report included the following recommendations: (1) publish a guideline document for land treatment, including current "rules of thumb" standards and considering amendment of §3.8 to include minimum operational requirements for land treatment; and (2) adopt minimum regulatory requirements for road spreading and publishing guidelines for application.
>
> For commercial and large centralized facilities, the team recommended that the Commission: (1) continue to require construction, operating, and closure plans for commercial/centralized facilities (2) require a siting plan for these facilities; (3) amend rules to reflect the requirement that applicants provide written notice to adjacent landowners of permit applications for commercial/centralized facilities; (4) impose permit term limits for pits associated w/commercial/centralized facilities and municipal landfills; (5) specify, by rule, construction, maintenance, operation, and closure requirements for commercial facilities; and (6) review permits for commercial and centralized disposal facilities at least once every five years.

In 2002, the RRC also recognized that (as it is still):[45]

> Current §3.8 is silent on management of certain oil and gas wastes, such as sewage and storm water. ***Technically under the current rule an operator would be required to get a permit to dispose of such wastes***; however, the Commission has received very few applications for such permits. The proposed new rules authorize management of such wastes under certain conditions so that a permit is not required. To avoid

[45] 27 TexReg 4277.

> duplication, the proposed new rules authorize disposal of sewage in accordance with regulations that already exist under the TNRCC or county health departments.

The RRC also recognized that "there is a clear legislative determination that ***interested persons***--not just ***affected persons***--are entitled to know the agency's rationale for the originally proposed rule. Following receipt of comments, the agency is obliged to consider fully the legal, factual, and policy-related issues raised by the rule, especially in the comments; the agency is obligated to evaluate such data and arguments in order to decide whether the proposed rule will be adopted verbatim, modified, or rejected in its entirety. The agency must write in its final order adopting the rule a reasoned justification that openly and adequately explains the agency's real reasons for the choices it makes."[46]

In sum, Rule 8's history shows the long-standing need of better regulations to protect Texas from the hazards of oil and gas waste management operations. The Commission has a unique opportunity to build back public trust with its rulemaking that it should not squander.

[46] 27 TexReg 4277-78 (emphasis in original).

PART 2 – SUMMARY OF OVERARCHING THEMES

The breadth and intricacy of this rulemaking makes it extremely difficult for meaningful participation by public stakeholders and community-based groups like Commission Shift who have been shut out of the drafting process thus far. No stakeholder group but industry has had the opportunity to sit side-by-side with Commission staff and walk through the 150+ pages of rule changes to understand how each section relates to each other, provide suggested changes and improvements to the rule, and to understand the intent behind each word.[47]

Nonetheless, Commission Shift has compiled a lengthy set of section-by-section comments on the rule draft, which is included herein as Part 3. To help the Commission navigate the comments in Part 3, Commission Shift overviews some of its top concerns here in Part 2. Commission Shift's comments have been shaped by the following three goals that it believes the Commission should return to throughout this drafting process. The Commission's goals with this rulemaking should be to:

(1) Better protect human health and the environment from waste pits and other waste operations.
(2) Lessen the burden on the public to protect their communities from unsuitable facilities.
(3) Improve the Commission & public's ability to enforce against bad actors.

Commission Shift is frustrated by what has and hasn't changed in the rulemaking process. While Commission Shift is glad for some of the smaller changes it has noticed—e.g., that registration will be required for authorized pits and that eventually waste hauling manifests will be tracked electronically—much more must be improved. Setbacks are still not protective enough and should not be eligible for exceptions without public input. Hardly any changes appear to have been proposed that would:

(1) improve the public's ability to participate in the permitting process;
(2) provide better and more widespread notice of applications;
(3) increase public access to data;
(4) improve the Commission's track record of enforcing these rules

To this end, Commission Shift makes suggestions in three key areas: public participation; permit approval; and data access / enforcement.

[47] As a Permian Basin Petroleum Association spokesperson put it in informal comments sent to the Commission dated September 20, 2023, "given the vast change being proposed, it takes time and consideration by a wide range of operational divisions within our member's organizations to provide the prudent feedback that has been requested[.]" "[O]ur members . . . set aside a significant amount of time from their daily duties to work internally to provide this feedback and know that the Commission recognizes the amount of analysis that a proposal like this demands from operators." Ex. 14, PBPA Comments (September 20, 2023). In contrast, the public and all other groups were given only thirty days to digest this proposed rulemaking.

1. Suggestions re: Public Participation

1. **Let the public participate on equal footing with industry in rewriting the rules.**

Commission Shift and members of the public themselves have had to lead the charge in outreach on these rules, while industry has had dozens of closed-door talks and access to the Commission for over 2 years. The Commission itself should host presentations and meetings with the public and concerned groups just like it has with industry; the public bears the biggest risk if the rules continue to be flawed. Staff at the Commission needs to actively answer and address the public's concerns, not just passively receive comments.

2. **Create a more participatory permitting process, for example one that would:[48]**
   - require a published "notice of intent" to apply for a permit at least 30 days before applying
   - send notice to all surface owners and groundwater conservation districts within one mile of the property boundary (in at least English and Spanish)
   - set all applications for a hearing once the application is complete, regardless if a protest is received (i.e., remove the need to protest in 15 days)
   - give at least 30 days notice of the hearing (same time frame applicants have to respond to protests)
   - prohibit modifications or supplements to the application once it is set for hearing (no costly moving target for the public & Commission to review)
   - at the hearing, allow all interested persons the opportunity to present testimony, facts, or evidence related to the application or to ask questions
3. **Require explicit surface landowner consent before a pit can be built onsite.[49]** Landowners should get to approve what types of waste are going to be put in any pit on their property before it happens. This was in a previous draft but removed after industry pressure.[50]
4. **Create a mailing list for all applications.** Commission should maintain an electronic mailing list open for anyone to subscribe so they can automatically be notified of applications in their area.

2. Suggestions re: Approving Good Projects

1. **Make the applicant, not communities, bear the burden of showing whether a project is protective of human or environmental health and safety.** Applicants should have the

[48] This applies at least to sections 4.125(a),(b), 4.133, 4.134(g),(h), 4.135(a),(b), (4.125(a), (b)), 4.134, 4.135), 4.204(2), 4.207, 4.212(c), 4.230(c), 4.246(c), 4.262(c),(d), 4.278(c),(d)
[49] This applies at least to 4.111(a).
[50] Compare Ex. 15, Excerpt of May 2023 Subchapter A Draft (§ 4.111) (highlights in original) with Ex. 16, Permian Basin Petroleum Association Comments (June 6, 2023) at 2; with proposed § 4.111.

actual and financial responsibility to collect accurate information to prove that their projects will be protective. Under both the current and draft rules, it falls to landowners and communities to pay to prove when projects won't protect health and safety. Prohibiting modifications of an application once its set for a hearing should help, but the Commission needs to demand that applicants provide more rigorous information when applying, rigorously question the claims in the application, and not simply award a permit once the application is "administratively complete." The rules should say that if a complete application "does not meet the requirements of [Chapter A] or other laws, rules, or orders of the Commission" the Commission "shall" deny it; not "may deny," as the current draft proposes.[51]

2. **Improve setbacks from sensitive sites and places.** Negative effects from these facilities extend far beyond the setbacks proposed, which are no more than 500 feet for even the largest landfills and no more than 1000 feet for commercial recycling facilities. Setbacks should be measured from the property boundary, not from an individual pit.[52] No exceptions or exemptions should be available without public input. Applicants should be required to describe clear risk mitigation measures meeting specific criteria in order to qualify for an exception.
3. **Improve design, operating, and monitoring for all pits.**
   - Groundwater investigations and monitoring should be required more often with fewer exceptions—once polluted, groundwater is basically impossible to clean up.[53]
   - Liner requirements (when and what to install) are still too lax.[54]
   - Too much leakage is allowed—1,000 gallons/day or more for a synthetically lined 1-acre pit is too much[55]
   - More sampling should be required, for all potential contaminants.[56].
4. **Don't allow a broad swath of exceptions, especially without public input.** New section 4.109 (and 4.205) would allow exceptions for anything other than financial security, notice, and sampling & analysis if the Commission finds the alternative is at least as protective of health and environment: i.e., siting, applications, design, construction, operation, closure, reporting, pilot programs, water protection, and waste hauling rules. The draft should be changed to vastly narrow allowable exceptions and all permits seeking exceptions should automatically go to hearing where any interested person should be allowed to participate. The Commission and Commissioners should not be granting exceptions without public input.

[51] This applies at least to 4.134 and 4.206(b). See also 4.204(2), 4.262(c), 4.278(c),
[52] This applies at least to 4.150(g), 4.219(b)(2), 4.256(b)(2), 4.272(b)(2).
[53] This applies at least to 4.114(h), 4.133(b), 4.241(d), 4.257(d), 4.273(d), 4.289(d).
[54] This applies at least to 4.114(6)(D), 4.115(b)(2)(A), (c)-(g), 4.119(g), 4.128(a), 4.151(a),(b)(3), 4.152(a),(b)
[55] This applies at least to (4.151(a),4.152(b)(1), 4.266(a), 4.275(a), 4.282(a), 4.291(a)).
[56] This applies at least to 4.114(h), 4.133(b), 4.241(d), 4.257(d), 4.273(d), 4.289(d)

3. Suggestions re: Data Access and Enforcement

1. **Give the public access to all data collected.** So bad actors can be found, all data on pits, waste, and waste hauling that operators collect should be sent to the Commission and made easily accessible by the public in a timely manner, not just kept available "upon request." The data available should not just be summaries, but the full documents.
2. **Create institutional memory of on-site & nearby applications.** All application files—including public comments—should be kept and made easily accessible by the public so similarly bad projects don't get proposed in inappropriate locations. Applicants should be required to review this data and analyze it in their applications.[57]
3. **Improve enforcement and apply meaningful penalties.** Communities largely agree—the existing rules aren't well enforced. The draft doesn't offer much in the ways to fix it. The penalty section, which is copied from 3.107, should strongly commit the Commission to vigorous, transparent, and speedy enforcement of the new rules. The remaining rules should be drafted to provide no wiggle room for bad actors to escape liability through wordsmithing.

In short, the regulations established in Subchapter A and B are for the express purpose of "**protecting public health, public safety, and the environment.**"[58] Revisions that have been included in this draft for other purposes—e.g., expediency for the regulated community—should take a back seat, as they often run counter to the purpose of this chapter[59] and the goal of protecting preventing pollution.

[57] This applies at least to 4.124, 4.212, 4.230, 4.246, 4.262, 4.278, 4.302.
[58] § 4.101(b) This subchapter establishes, **for the purpose of protecting public health, public safety, and the environment** within the scope of the Commission's statutory authority, the minimum permitting, operating, monitoring, and closure standards and requirements for the management of oil and gas wastes under the jurisdiction of the Commission.
[59] §4.101 (a) No person conducting activities subject to regulation by the Railroad Commission of Texas may cause or allow pollution of surface or subsurface water in the state; § 4.110 (71) Pollution--The alteration of the physical, thermal, chemical, or biological quality of, or the contamination of, any surface or subsurface water that renders the water harmful, detrimental, or injurious to humans, animal life, vegetation, or property, or to public health, safety, or welfare, or impairs the usefulness or the public enjoyment of the water for any lawful or reasonable purpose.

PART 3 — SECTION-BY-SECTION COMMENTS

Commission Shift provides the following section-by-section comments on the draft revisions to Subchapters A and B. These line-item edits should be read in context with its comments in Parts 1 and 2. Commission Shift welcomes a dialogue with the Commission as any questions or concerns arise during the Commission's review of these comments, just as industry has been allowed to dialogue with the Commission for the past two years in the drafting of these rules. Commission Shift reserves the right to alter, refine, and expand its position from those stated herein as it obtains more information about the proposed changes and their impact on communities and environmental health.

Subchapter A

1. DIVISION 1

§4.101. Prevention of Pollution, Page 1 of Draft Rules

Commission Shift notes that the language of 4.101(a) is already found in current rule 3.8(b), and despite its seemingly strong tone requiring the protection of ***all*** surface or subsurface water in the state,[60] it has failed to enforce the previous rules to protect the health and environmental safety of Texans, as discussed above. Thus, Commission Shift urges the Commission to better enforce the policies of prohibiting pollution that are espoused in this section. Commission Shift suggests adding a section (d) asserting the agency's commitment to investigations and enforcement: "<u>The Commission shall enforce these rules to prevent pollution, including by promptly and thoroughly investigating alleged violations of these rules</u>."

§4.102. Responsibility for Oil and Gas Wastes, Page 1

Commission Shift disagrees that "process knowledge" is sufficient to characterize wastes, as §4.102(a)(1) and §4.102(a)(3) would allow. Process knowledge does not rely on laboratory analysis, but presumes what pollutants will be in a waste based on where the waste came from and what it may have been mixed with. However, unexpected contaminants can exist downhole, and additional contaminants can be introduced to the waste stream as it is transferred from generator to receiver and beyond, either deliberately or inadvertently. Process knowledge also does not identify constituent levels, i.e., the quantity of contaminant that is present in the waste.

It is imperative that laboratory analyses—and not process knowledge—be used when waste is generated at or will be transferred to a commercial facility (or between facilities)[61] and when

[60] This includes both drinking water aquifers and any other subsurface waters, no matter if "percolating, perched or otherwise." § 4.110(84).

[61] In other words, §4.102(a)(2) should be rewritten to say: "Laboratory analysis of waste ~~may~~ <u>shall</u> be required for waste generated at a commercial facility, as that term is defined in §4.110 of this title, or when waste is transferred from one commercial facility to another."

determining if a waste is hazardous.[62] The treatment and disposal mechanisms that will suffice for any given waste stream depending on what's in the waste (and in what quantities). If the waste stream is sufficiently contaminated, a facility may not be legally allowed to accept such waste. The waste may also pose serious hazards for nearby residents, drinking water supplies, and the environment. The Commission should identify a specific list of parameters that the waste must be tested for. All laboratory testing should be conducted by an accredited third-party lab, as described in § 4.124(e)(3)(A).

As for subsections (b) – (d), Commission Shift understands that this language may be included because of legislation.[63] However, negligent and reckless action should be prohibited as well. Requiring that the Commission or others show a "knowing" violation of (b) – (d) can be exceedingly difficult. Nor does subsection (e) solve the problem for communities; all of these subsections are from current rule 3.8(d)(5). Commission Shift urges the Commission to use this rulemaking to go beyond the business-as-usual regulations and create real incentives for operators to use only properly permitted entities.

As for §4.102(f),[64] Commission Shift requests that the Commission explain why the Commission has emphasized that it is a person "who plans to utilize" the services of a carrier who is under a duty to investigate, as opposed to "a person who utilizes" such services. The Commission should confirm in writing that this is not a loophole operators could exploit to avoid investigating whether a carrier has a permit or not. Subsection (f)(2) should also include liability negligence: A generator should be liable for improper disposal if the generator was negligent in failing to recognize that the carrier or receiver was likely to improperly dispose of wastes and negligently failed to take reasonable steps to prevent improper disposal.

§4.104. Coordination Between the Commission and Other Regulatory Agencies, Page 3

Commission Shift supports the retention of § 4.104(b) in the new draft, which is also in current 3.8, and prohibits the operation of a facility before it has all required permits. However, section (b) should also require the applicant to forward a copy of any additional required authority to the Commission before the receipt of waste. This way the Commission can better direct concerned

[62] In other words, §4.102(a)(3) should be rewritten to say: "The generator of an oil and gas waste that is not exempt from regulation under Subtitle C of the federal Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976, as amended, 42 USC §6901, et seq. as described in 40 CFR §261.4(b), shall determine if such waste is a hazardous oil and gas waste by ~~applying process knowledge of the hazard characteristics of the waste in light of the materials or processes used or~~ by conducting laboratory analysis of ~~testing~~ the waste."

[63] E.g., Tex. Water Code § 29.043, which states "No person may knowingly utilize the services of a hauler to haul or dispose of oil and gas waste off the lease, unit, or other oil or gas property where it is generated if the hauler does not have a permit as required under this chapter."

[64] §4.102(e) states: "Any person who plans to utilize the services of a carrier or receiver is under a duty to determine that the carrier or receiver holds the appropriate authority from the Commission to manage or transport oil and gas wastes."

community members to the proper regulatory authority if and when complaints arise. Commission Shift also urges the Commission to be more proactive in determining jurisdiction and coordinating with the TCEQ.

§4.107. Penalties, Page 4

The Commission has largely copied existing Rule 3.107 into 4.107, and has not proposed penalties related to Rule 73.[65] The Commission should clarify what will happen to Rule 107 and take this opportunity to revise the language in 4.107 to address the enforcement problems that communities keep experiencing.

The Commission may be somewhat limited by statute from enacting all of following changes but the fact is that while voluntary corrective action **can be** an effective component of the enforcement action, that is not always so, thus the language used in (a) should be "can be an effective component" but not "is an effective component."

Again, unless it is barred by statute, the Commission should omit the last two sentences of (b) because it hamstrings the Commission's abilities to enforce its rules and penalizes good actors over bad actors. This Commission should not foreclose its ability to automatically enforce its rules (the penultimate sentence). Nor can all violations be corrected by operators before being referred to legal enforcement (the last sentence). This language would prohibit the Commission from referring egregious, deliberate violations contrary to public and environmental health & safety directly to legal enforcement. While some minor violations (e.g., lack of signage) might be suitable for voluntary correction, other violations are not. The Commission should omit these sentences or clarify that the Commission reserves the right to immediately pursue legal action or any other means necessary to enforce its rules and protect the public.

§4.108. Electronic Filing Requirements, Page 6

All filed documents should be made publicly available and searchable through the Commission's public-facing electronic database (e.g., including monthly quarterly, semi-annual, and annual reports as described in 4.130).

All of the documents that operators are required to retain on request should be instead filed automatically and made available to the public, including as stated in (a non-exhaustive list):

4.111 (closure compliance for operations authorized by rule),

4.112 (distilled water sampling proof),

4.114 (compliance documentation for authorized pits for 4.113 and 4.115; closure documentation),

4.115 (pit liner integrity for a variety of authorized pits),

[65] It is not possible to provide meaningful feedback on penalties without having Tables 1 – 5.

4.130 (waste reporting for permitted facilities),

4.142 (commercial spill and stormwater plans),

4.172 (reclamation plant operation)

4.194 (waste profile, manifest, and other documentation).

Making these documents publicly available lets the public help monitor the compliance at these facilities and inspires confidence that good-actor facilities are being responsibly run. It also dovetails with recommendations made as early as 2000 by the interdisciplinary review board.[66] As such, Commission Shifts request that each of these sections listed above be edited to require that these documents be timely filed with the Commission and uploaded to the public-facing electronic database.

§4.109. Exceptions, Page 7

Commission Shift objects strongly to §4.109. Exceptions to water-protection rules aren't contemplated in the current version of 16 TAC § 3.8 and shouldn't be allowed in the new rules. Exceptions are a dangerous loophole and will allow existing facilities to continue operating even if evidence exists that public and environmental health is being put at risk. Charging an exception fee does not address the problems with the lack of meaningful participation in reviewing exceptions. The public should be automatically allowed to weigh in when exceptions are requested—any application that includes a request for exception should automatically be set for hearing, and the 15-day deadline to protest should be waived—any person with relevant information should be allowed to present that information at the hearing.[67]

As written in subsection a, an applicant can request an exception for anything other than financial security, notice, and sampling and analysis. This means that an applicant can receive an exception on things like (a non-exhaustive list): applications, siting, design & construction, operation, monitoring, closure, reporting, all of the miscellaneous permits (Division 9), all of the waste transportation rules (Division 10); and all of the surface water protection requirements (Division 11).

Subsection (c) gives a 1-year grace period for permitted facilities, as it states that:

> until [insert one year after effective date of rulemaking] the director may grant special exceptions solely for the purpose of issuing permits for facilities and waste management units that were authorized pursuant to §3.8 of this title (relating to Water Protection) prior to [insert the effective date of rulemaking] but that are no longer authorized pursuant to this subchapter.

[66] "The review team encourages RRC to diligently pursue efforts to upgrade its information technology to allow the district offices to routinely share information with management and the public." Ex. 6 STRONGER Texas Review, 2003 (citing 2000 Guidelines 4.2.8.3, 8.2).

[67] And under no circumstances should operators or any other person be able to apply for exceptions outside of a permitting process and outside of a forum that allows the public to weigh in.

The Commission should confirm that § 4.109 combined with § 4.122 means that after one year, the conditions in every permit that comes up for renewal, transfer, or amendment will have to conform to these new rules.

Commission Shift also has concerns about subsection (e), which limits when a hearing is granted. A hearing should automatically be held whenever a permit application is filed (including amendments, transfers, and renewals) and at a bare minimum, should be automatic whenever an exception is requested. It should not just be for rejections of exceptions, and anyone should be able to request one, not just the applicant or permittee.[68] The public has a stake in exceptions and must be allowed to weigh in as to whether the requested alternative is "at least equivalent in the protection of public health and safety, and the environment."

2. DIVISION 2: DEFINITIONS

§4.110. Definitions, Page 7

Commission Shift expresses concern about the following definitions:

(1) 25-year, 24-hour rainfall event

Commission Shift objects to allowing Technical Permitting to define these rainfall events based on any source other than the National Oceanic and Atmospheric Administration. NOAA is the only source known to Commission Shift that regularly updates its data.[69] As such the definition in §4.110(1) should be revised to state that a 25-year, 24-hour rainfall event is:

> The maximum 24-hour precipitation event with a probable recurrence interval of once in 25 years, as defined by the National Weather Service and published by the National Oceanic and Atmospheric Administration ~~or other source approved by Technical Permitting~~.

(2) 100-year flood

Commission Shift objects to the vague language in this definition. The Commission should not invent a vague definition that might be subject to debate by applicants or operators.[70] The Commission should use a standard definition. The definition in §4.110(2) should be revised to remove debate over what constitutes "a significantly long period":

> A flood that has a 1.0% or greater chance of occurring in any given year or a flood of a magnitude equaled or exceeded once in 100 years on the average ~~over a significantly long period~~.

[68] The 2022 STRONGER Guidelines urges that "The right to appeal or seek administrative and/or judicial review of agency action ***should be available to <u>any</u> person*** having an interest which is or may be adversely affected, or who is aggrieved by any such action." Ex. 11 2022 STRONGER Guidelines at 23.
[69] For an explanation of why NOAA's Atlas 14 is more appropriate than other outdated methods like TP-40, see Ex. 17 Under Water & Unaware. (June 1, 2022) https://www.citizen.org/article/under-water-unaware/
[70] This definition differs even from the one now proposed to be stricken from Subchapter B, which stated: "a 100-year flood . . . is a flood that has a one percent or greater chance of occurring in any given year." § 4.204(1).

(3) 100-year flood plain

Soils maps are not appropriate ways to determine the location of a floodplain. If FEMA data is not available, an acceptable alternative method could be a flood zone analysis done by a professional engineer with FEMA-approved software for flood mapping.[71] The definition in §4.110(3) should be revised to state that a 100-year flood plain is:

> The lowland and relatively flat areas adjoining inland and coastal waters, including flood-prone areas of offshore islands, that are inundated by the 100-year flood, as determined from maps or other data from the Federal Emergency Management Agency (FEMA)~~, or, if not mapped by FEMA, from the United States Department of Agriculture (USDA) soil maps.~~ or a flood zone analysis done by a professional engineer with FEMA-approved software for flood mapping.

(4) action leakage rate:

The proposed definition “The fluid flow rate into a leak detection system that constitutes a primary liner failure” is too simplistic. In actuality, the Action Leakage Rate is “the calculated volume of waste liquid that has bypassed the primary liner into the leak detection layer at a rate of gallons per acre per day that if exceeded indicates severe failure of the primary liner and triggers the requirement to find the cause(s) of the failure and repair the liner.”

(8) “affected person”

The definition of affected person is ambiguous and difficult for citizens to understand whether they fall within this definition. It has happened in the past that a nearby resident has spent significant time, energy, and money in protesting an application before ultimately being told that they do not have affected-persons status. The Commission should eliminate this guesswork and define affected person to explicitly include ***at a minimum*** all persons within one mile of the property boundary on which the authorized or permitted activity takes place. The definition in §4.110(8) should be revised to state that an affected person is:

> A person who, as a result of the activity sought to be permitted, has suffered or may suffer actual injury or economic damage other than as a member of the general public or a competitor. Affected persons include at a minimum those surface owners, groundwater conservation districts, and **residents** within one mile of the property boundary on which the activity takes place.

(10) *aquifer*

Commission Shift does not have explicit feedback on this definition at the moment, but notes that the Commission’s directive is to protect all subsurface water, not simply aquifers “capable of yielding significant quantities of groundwater.” Shallow water bearing zones that won’t give sufficient quantities of groundwater still merit protection.[72] In the current draft, the term aquifer is used in only

[71] FEMA identifies HEC-RAS as such software from the US Army Corps of Engineers, which incorporates watershed and topography data.
[72] Such zones can also be hydrologically connected to surface water and/or water bearing formations at depth via infiltration.

two other locations in Subchapter A and in a manner that appears to recognize that other groundwater is also protected. However, Commission Shift requests that the Commission reiterate in its rulemaking that ***all*** subsurface water—whether it is located in an aquifer or not—will be protected equally.

(13) *Basic sediment*

Basic sediment has been defined in this draft to be:

> A mixture of crude oil or lease condensate, water, sediment, and other substances or hydrocarbon-bearing materials that are concentrated at the bottom of tanks and pipeline storage tanks (formerly known as tank bottoms).

However, this term could lead to confusion because it is common in industry to define a mixture of sediment and water as just that—as “basic sediment ***and*** water” (BS&W). The Commission should clarify if there is a substantive difference between BS&W, basic sediment, and tank bottoms (which was the term previously used in Rule 57).

(21) “commercial facility”

Commission Shift strenuously objects to the proposed definition of a “commercial facility” because it is too narrow as proposed:

> A facility permitted under this chapter, whose operator receives compensation from third parties for the management of oil and gas wastes, whose primary business purpose is to provide such services for compensation, and receives oil and gas wastes by truck. In this paragraph, a third party does not include an entity that wholly owns the operator of the facility permitted under this chapter.

There are four major problems with this definition: (1) its unconventional nature; (2) its exclusion of certain third parties, (3) its definition based on transportation method; and (4) its lack of parallel syntax.

Unconventional definition. It is important to have a sufficiently broad definition of commercial facility, because the proposed regulations impose stricter standards and permitting requirements on facilities defined to be “commercial.”[73] At first glance, stricter standards for commercial would seem to make sense—the conventional understanding of a commercial facility is a larger operation that handles more waste and operates for much longer when compared to a non-commercial facility. In other words, commercial facilities are typically understood to be larger, riskier, with higher traffic and with potentially some portion or all of the waste stored in-place for a longer period or perpetuity. However, the proposed definition of “commercial facilities” does not incorporate any of such factors, it instead refocuses the concept of commercial to operations accepting waste for compensation from third-parties that don’t also own the facility. But such a narrow definition does nothing to meet the

[73] The commercial definition also affects what facilities can be built in sensitive commercial areas: as proposed, 4.197(a)(1) only prohibits “commercial” disposal pits from being built in coastal natural resource areas. Non-commercial disposal pits, pits holding waste for anything other than “permeant interment,” and every other waste disposal facility is not prohibited by rule.

regulations' stated purpose of "protecting public health, public safety, and the environment"[74]—commercial facilities should not be defined from the perspective of who is bringing the waste and how, but with the inherent risks and hazards associated with the facility.

This definition is also out-of-step with how other states define commercial facilities.[75] Louisiana defines a commercial facility as "a storage, treatment and/or disposal facility which receives, treats, reclaims, stores and/or disposes of oil and gas waste for a fee or other consideration." 43 La. Admin. Code Pt XIX, § 501.[76] The RRC could harmonize Louisiana's definition with the terminology used in Texas to be "a facility that manages oil and gas wastes for a fee or other consideration."

Third-parties. At a bare minimum, this definition should not create a new definition to "third-parties" and should include facilities whose operators receive compensation from entities that wholly own the operator of the facility.[77] As written, if the facility is a wholly-owned subsidiary of the generator (i.e. if the generator is the facility's parent), it would not be a commercial facility. Corporate entities sometimes choose to form subsidiaries to protect assets and mitigate liability. Subsidiaries are typically treated as separate entities when it comes to holding them responsible for each other's actions and protecting the parent company from the action of its subsidiaries. The proposed definition for commercial facility would blur wholly-owned subsidiaries back into their parents, creating a loophole for facilities to not fall within the commercial definition (and the elevated protections for communities the rules provide) as long as they are accepting mostly their parent company's wastes. In other areas of the law, this sort of preferential treatment is not allowed.[78]

A subsidiary relationship between a receiver and third party is possible. For example, Waste Connections reports owning R360 Environmental Solutions as a subsidiary and operating waste treatment and disposal facilities, one of which is in Stanton, Texas.[79] Such a large operator as Waste

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[74] § 4.101(b).

[75] The definition recommended by STRONGER, a "non-profit corporation . . . formed to educate regulators and the public as to the appropriate elements of a state oil and gas exploration and production regulatory program" is similar:

> "Commercial Disposal Facility: A facility whose owner(s) or operator(s) receives compensation from others for the temporary storage, reclamation, treatment, and/or disposal of produced water, drilling fluids, drilling cuttings, completion fluids, and any other RCRA exempt E&P waste, and whose primary business objective is to provide these services. These facilities may, under certain circumstances, also accept non-exempt, non-hazardous wastes generated from E&P operations. This definition also includes facilities whose owner(s) or operator(s) receives compensation from others for E&P NORM-related storage, decontamination, treatment, or disposal."

Ex. 11 20222 STRONGER Guidelines at 7, 49. https://www.strongerinc.org/wp-content/uploads/2022/07/2022-Edition-STRONGER-Guidelines.pdf

[76] The full definition is: "Commercial Facility--a legally permitted E and P Waste storage, treatment and/or disposal facility which receives, treats, reclaims, stores, and/or disposes of E and P Waste for a fee or other consideration. For purposes of this definition, Department of Environmental Quality (DEQ) permitted facilities, as defined by LAC 33:V and VII, which are authorized to receive E and P Waste, are not covered by this definition. However, such facilities must comply with the reporting requirements of § 545.K herein if E and P Waste is accepted."

[77] Nowhere else in the Commission's current rules is "commercial facility" defined so narrowly.

[78] E.g., the corporate veil between a subsidiary and its parent protects the two entities from liability except under very narrow circumstances.

[79] Ex. 18 Waste Connections Sustainability Report (2022) at 27. https://cdn.wasteconnections.com/resources/documents/sustainability/2022/Waste+Connections+2022+Sustainability+Report.pdf. See also Ex. 19, Allan Gerlat. *Waste Connections to Buy Oil Field Waste Company for $1.3 Billion*

Connections is clearly a commercial entity engaged in commercial activities at a commercial facility (by any conventional and logical definition of the term); large commercial facilities should not fall outside the definition of a commercial simply because their operators are vertically integrated and own the facilities where they dispose of waste.[80] The Commission should clarify that operators with corporate relationships like Waste Connections and R360 would be treated as commercial facilities. For the sake of public trust and transparency, the Commission should also disclose why this definition was rewritten so many times, and which companies stand to benefit.

Transportation loophole. The definition of commercial also should not hinge on whether the waste is delivered by "truck" or not. Waste delivered in any manner—by vessel, barge, shipping container, pipeline, car, rail, drone, air, horseback, or foot—should be covered by this rule.[81] Current Rule 78's definition of commercial is not so narrow (includes waste "partially trucked or hauled,"[82] nor are the several versions that were considered in the two years industry had to create this rule.[83]

(Sept. 17, 2012) https://www.waste360.com/mergers-and-acquisitions/waste-connections-buy-oil-field-waste-company-13-billion

[80] Ex. 20, 2022 SEC Filing at 8. ("As of December 31, 2021, we owned or operated 71 MSW landfills, 12 E&P waste landfills, which only accept E&P waste and 14 non-MSW landfills, which only accept construction and demolition, industrial and other non-putrescible waste. Eight of our MSW landfills also received E&P waste during 2021***. We generally own landfills to achieve vertical integration in markets where the economic and regulatory environments make landfill ownership attractive***.") (emphasis added) https://www.sec.gov/Archives/edgar/data/1318220/000155837023001404/wcn-20221231x10k.htm

[81] Waste transfer by barge or rail is possible. For example, across the country Waste Connections owns or operates "E&P waste transfer stations with marine access. Transfer stations receive, compact and/or load waste to be transported to landfills or treatment facilities ***via truck, rail or barge***." Ex. 20 2022 Waste Connections SEC Report at 10. https://www.sec.gov/Archives/edgar/data/1318220/000155837023001404/wcn-20221231x10k.htm As that company explained in its 2012 filing, other methods are possible too: "We receive flowback water, produced water and other drilling and production wastes at our facilities ***in vacuum trucks, dump trucks or containers deposited by roll-off trucks***. ***In certain markets we offer bins and rails systems*** that capture and separate liquid and solid oilfield waste streams at our customers' well sites and deliver the drilling and production wastes to our facilities. ***Waste generated by offshore drilling is delivered by supply vessel from the drilling rig to one of our transfer stations, where the waste is then transferred to our network of barges*** for transport to our treatment facilities." Ex. 21 2012 SEC filing at 6. https://www.sec.gov/Archives/edgar/data/1057058/000119312513085841/d431432d10k.htm

[82] Rule 78 sets the requirements for financial security. 16 TAC § 3.78(a)(3) Commercial facility--A facility whose owner or operator receives compensation from others for the storage, reclamation, treatment, or disposal of oil field fluids or oil and gas wastes **that are wholly or partially trucked or hauled** to the facility and whose primary business purpose is to provide these services for compensation if:

(A) the facility is permitted under §3.8 of this title (relating to Water Protection);

(B) the facility is permitted under §3.57 of this title (relating to Reclaiming Tank Bottoms, Other Hydrocarbon Wastes, and Other Waste Materials);

(C) the facility is permitted under §3.9 of this title (relating to Disposal Wells) and a collecting pit permitted under §3.8 is located at the facility; or

(D) the facility is permitted under §3.46 of this title (relating to Fluid Injection into Productive Reservoirs) and a collecting pit permitted under §3.8 is located at the facility.

[83] The October 2022 version proposed a simple, bright-line definition that Commission Shift would favor instead of the one proposed now: "Commercial facility--A facility whose owner or operator receives compensation from others for the receipt, handling, storage, treatment, reclamation, recycling, or disposal of oil field fluids or oil and gas wastes." Ex. 23, October 2022 Subchapter A draft, (excerpt).

The ”commercial” definition in the commercial recycling rules is also not so narrow and contains no limitation based on mode of transportation.[84] In addition, Subchapter A's proposed definition of "container" (§4.110(25)) includes waste receptacles beyond those that are transported by truck (including receptacles transported by vessel and barge).[85] The waste hauling rules do carve out only certain transportation methods for regulation but with different phrasing: in one place applying to the transport of wase "by any method other than by pipeline,"[86] and another regulating transport "by vehicle."[87] The Commission should use standardized language wherever possible to avoid confusion and potential litigation.

Parallel syntax. Parallel syntax—in which all items of a list have a parallel structure—helps operators and their counsel parse regulations. The commercial definition includes a non-parallel 3 part list ("whose operator . . . , whose primary business purpose. . . , and requires"). Commission Shift urges the Commission to fix these drafting errors throughout this proposed rulemaking and before the formal comment period begins so that its meaning can be parsed and meaningful feedback given.

Finally, Commission Shift requests that the Commission clarify that once a facility qualifies as commercial, ***every*** waste management unit in that facility must be addressed and included in the permit. In other words, pits and sumps that might otherwise be permitted-by-rule under Division 3 (for example if they were located at the drill site) should not be allowed to be permitted by rule if they are part of a commercial facility. It is too confusing for the public and regulators to have both permitted and "authorized" activities at the same property and could tempt bad operators to use "authorized" operations to circumvent the notice that goes along with permitting (and subsequent review). The definition in §4.110(21) should be revised to state that a commercial facility is:

> <u>A facility whose owner or operator receives compensation from others for the management of oil and gas wastes. [88] All waste management units on the same</u>

[84] § 4.204(3) contains no "transportation" limitation. 16 TAC 4.204(3) Commercial recycling facility--A facility whose owner or operator receives compensation from others for the storage, handling, treatment, and recycling of oil and gas wastes and the primary business purpose of the facility is to provide these services for compensation, whether from the generator of the waste, another receiver, or the purchaser of the recyclable product produced at the facility. Includes recycling of solid oil and gas wastes on or off lease. Does not include non-commercial fluid recycling as defined in §3.8 of this title.

[85] §4.110(25): "Container--A pit, sump, tank, vessel, truck, barge, or other receptacle used to store or transport oil and gas waste."

[86] §4.193(a): "Prohibitions. A person who transports oil and gas waste for hire ***by any method other than by pipeline*** shall not haul or dispose of oil and gas waste off a lease, unit, or other oil or gas property where it is generated without a valid oil and gas waste hauler permit. A permittee under this division shall not gather oil, gas, or geothermal resources unless otherwise authorized by Commission rules. An oil and gas waste hauler shall not transport oil, gas, or geothermal resources in the same vehicle being used to transport oil and gas wastes other than incidental volumes of skim oil normally present in produced water or other oil and gas wastes. (emphasis added).

[87] See § 4.191(a). Division 10 is the only place in Subchapter A where vehicle is defined: For the purposes of this permit, "vehicle" means any truck tank, trailer tank, tank car, vacuum truck, dump truck, garbage truck, or other container in which oil and gas waste will be hauled by the permittee." 4.193(e)(2).

[88] This language is substantively identical to the language proposed to the Commission in October 2022 before industry pushback, except the phrase "receipt, handling, storage, treatment, reclamation, recycling, or disposal of oil

> property as a commercial facility must be permitted. No such waste management unit may be authorized through Division 3 of this subchapter.

(#) Construction Quality Control (CQC)

Commission Shift suggests that the Commission consider defining a new term "Construction Quality Control (CQC)." CQC refers to the quality control systems used to ensure that a construction project (such as the installation of a liner) is properly performed. Many liner installers already have QA/QC practices to ensure their work is quality and complies with applicable regulations. The TCEQ also already regularly collects this information from operators to ensure that the liners for municipal waste landfills are installed correctly.[89] The Commission should consider modifying TCEQ's liner CQC form for waste pit operations and requiring operators to submit this form as part of the information collected when pits are constructed. Commission Shift proposed the following definition for construction quality control:[90]

> Construction Quality Control (CQC) - A planned system of inspections that is used to directly monitor and control the quality of a construction project. Construction quality control is normally performed by the geosynthetics installer and is necessary to achieve quality in the constructed or installed system. Construction quality control (CQC) refers to measures taken by the installer or contractor to determine compliance with the requirements for materials and workmanship as stated in the plans and specifications for the project.

CQC plans should be required for all permitted operations, at a minimum. A permitted operation should not be allowed to operate until a CQC form has been received and reviewed by the Commission.

(24) contact stormwater; (62) *non-contact stormwater;* and (83) *stormwater*

As an initial matter, Commission Shift believes that the Commission should have a means of protecting the public and environment from water that has come into contact with oil and gas waste (or areas used to contain such waste) that is not just precipitation but that is also water from other sources (e.g., hauled in by truck, diverted from streams, pumped from wells, or otherwise). One way to do so could be revising the definition of stormwater to include water of any kind, as follows:

> (83) Stormwater--~~Precipitation~~ Water that falls onto and flows over the ground surface and does not infiltrate into the soil. See also "Contact stormwater" and "Non-contact stormwater."

field fluids or" has been replaced with "management of," to accommodate the revised definitions in the October 2023 draft.

[89] Ex. 23 Municipal Solid Waste Facility Geomembrane/Geosynthetic Liner Evaluation Report. (TCEQ) https://www.tceq.texas.gov/downloads/permitting/waste-permits/msw/forms/10070.docx (describing how "This liner evaluation report is required to document that the liner was constructed as designed in accordance with the issued registration or permit and meets the TCEQ regulatory requirements prior to unit operation. This report is to be supplemented with those quality-assurance/quality-control (QA/QC) tests as detailed in the liner quality control plan (LQCP) and shall be the basis of documentation of the quality control and acceptance of the constructed liner.").

[90] This definition can be found in Ex. 24 Field Integrity Evaluation of Geomembrane Seams (and Sheet) Using Destructive and/or Nondestructive Testing (2013) at 4 https://geosynthetic-institute.org/grispecs/gm29.pdf

Then logically the definition of stormwater could be divided between contact and non-contact, with no ambiguous third category of stormwater. That is not the case, however, because (24) and (62) use different language (highlighted in bold).

> (24) Contact stormwater--Stormwater that has **come into contact with oil and gas wastes** or areas that are **permitted** to contain oil and gas wastes, regardless of whether oil and gas waste is currently being contained in the area. See also "Non-contact stormwater" and "Stormwater."
>
> (62) Non-contact stormwater--Stormwater that, **by design or direction**, has not come into contact with areas containing oil or gas wastes or areas permitted to contain oil and gas wastes. See also "Contact stormwater" and "Stormwater."

Commission Shift offers the following revised definitions, which is intended to fully capture all scenarios:

> (24) Contact stormwater--Stormwater that has come into contact with oil and gas wastes or <u>with</u> areas that are permitted <u>or authorized</u> to contain oil and gas wastes, regardless of whether oil and gas waste is currently being contained in the area. See also "Non-contact stormwater" and "Stormwater."
>
> (62) Non-contact stormwater--Stormwater that~~, by design or direction,~~ has not come into contact with <u>oil and gas wastes nor with</u> ~~areas containing oil or gas wastes or~~ areas <u>that are</u> permitted <u>or authorized</u> to contain oil and gas wastes<u>, regardless of whether oil and gas waste is currently being contained in the area</u>. See also "Contact stormwater" and "Stormwater."

The Commission should ensure that whatever definition is used for these terms, contact stormwater should include stormwater that has come in contact with any oil and gas waste that has been tracked throughout the facility and is no longer in an authorized or permitted waste management facility.

(25) "container" and (70) "pit"

Commission Shift requests clarity on why the definition of "container" has been expanded to include a "pit" and why "pit" is defined to include a container. In other words, when viewed together, the definitions of "pit" and "container" are circular, rendering them difficult to parse. As part of its rulemaking, the Commission should provide examples as to what is and is not included as a pit so that the regulated community and the public can better understand the scope of these regulations.

(27) dewater

Commission Shift requests that the Commission incorporate the definition of "free liquids" into this term.

(39) freeboard

Freeboard for pits should be at least two feet ***plus*** the 24-hour 25-year rainfall event. This appears to be the Commission's intent for authorized pits;[91] but appears to have been inadvertently

[91] See § 4.114(c)(2) ("An authorized pit shall be large enough to ensure adequate storage capacity to maintain two feet of freeboard and to contain:

left out from the permitted pit rules.[92] Freeboard that includes the 24-hour, 25-year rainfall event is important because water isn't static—especially during storms—wind and wave effects can cause waste spills, so liquids should never be allowed to approach the lid of containers, sumps or pits. In addition, the rules for permitted operations allow delay before contact stormwater need be collected and removed, running the risk that additional water will build up in the pit during that time.[93] The definition in §4.110(39) should be revised to state that freeboard is:

> The vertical distance between the top of a pit or berm and the highest point of the contents of the pit or berm, which shall be two feet plus the distance needed to contain the 24-hour 25-year rainfall event.

(45) "*groundwater"*

The proposed rules define groundwater as "[s]ubsurface water in a zone of saturation." This was not previously defined in Rule 8. The Commission should confirm that the definition of groundwater includes any water under the surface of the ground, both aquifers and any subsurface water, regardless of quantity and quality.[94]

(48) *land farming*

The proposed definition of land farming '(50) Landfarming--A land application waste management practice in which oil and gas waste is mixed with or applied to land in such a manner that the waste will not migrate from the authorized or permitted landfarming cell" does not include the most important part – that the waste is treated so that the hydrocarbons are utilized by microbes and heavy metals are attenuated in soils. Commission Shift recommends the following definition:

> (48) Landfarming--A land application waste management practice in which oil and gas waste is mixed with or applied to appropriately prepared soils in a treatment cell in such a manner that the waste will be reduced using monitored microbial degradation and does not migrate from the authorized or permitted landfarming cell.

(49) *Land application*

In the previous draft rule, the definition of "land application" included the phrase "in such a manner than the waste will not migrate off the area," and the proposed definition of "land farming"

(A) the volume of material to be managed; and
(B) the volume of precipitation from a 25-year, 24-hour rainfall event.")

[92] See § 4.151(b)(2) ("Freeboard. Unless otherwise required by permit or rule, the permittee shall maintain all pits such that each pit maintains a freeboard of at least two feet."); §§ 4.161(b) & 4.162(b)(2)(B)(failing to include the 24-hour, 25-year flood in the rules on landfarm construction). The Commission should modify the language in § 4.151 and 4.161 to mirror that in § 4.114(c)(2), so that all pits can handle the 24-hour 25-year flood while still maintaining at least two feet of freeboard.

[93] § 4.128(b)(4) requires stormwater to be collected "within 24 hours of ***accessibility***," which may not be possible for several days during sever weather events. It is therefore imperative that the Commission require sufficient freeboard on all waste management units.

[94] E.g., congruent with TCEQ RULE § 297.1 ("(22) Groundwater--Water under the surface of the ground other than underflow of a stream and underground streams, whatever may be the geologic structure in which it is standing or moving.") and the definitions in other states, like Oklahoma's 785:30-1-2 ("Groundwater" means fresh and marginal water under the surface of the earth regardless of the geologic structure in which it is standing or moving outside the cut bank of any definite stream. [82:1020.1(1)]).

includes a similar limitation. The current proposed definition for land application—"An authorized or permitted waste management practice in which oil and gas waste is placed directly on the ground surface"—does not include this caveat. Commission Shift supports adding this phrase back in the definition of land farming because it would be more protective of human health and the environment. In the alternative, Commission Shift requests that the Commission clarify that this limitation is incorporated in this definition despite it not being made explicit.

(52) *Leak detection system*

The way this definition is written has the potential to cause confusion, thus the Commission should revise this definition to be clearer. The draft proposes to define this term as:

> A system used to detect leaks **below the liner of pits**. A leak detection system may be installed **in a location other than below the liner** of pits.

In the first sentence, the leak detection systems are defined to be systems used to detect leaks from pits only. Conventional leak detection systems for pits are installed between the primary and secondary liners of a pit (as in the figure), yet as drafted, the proposed definition envisions (in the second sentence) that these systems could be installed in some "other" location.

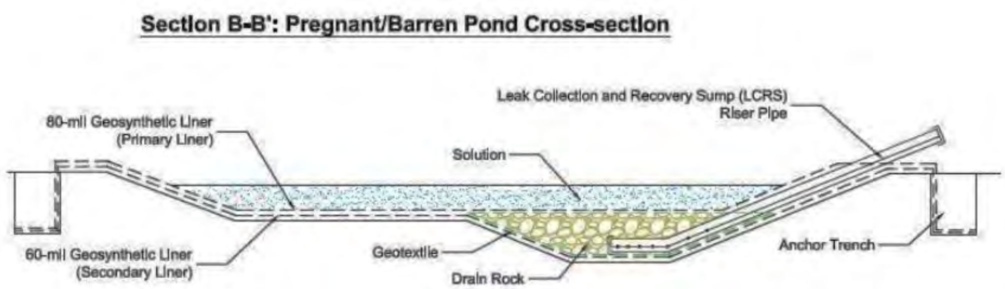

Figure 1: Process ponds are required to be double-lined with a functioning leak detection system. [95]

Commission Shift requests that the Commission clarify what pit leak detection systems are acceptable that are ***not*** installed below the liner and elaborate on how leaks would be detected, tracked, and regulated that would be accurate enough to detect a loss of liquids not otherwise accounted for.[96] If instead the Commission meant to describe leak detection systems used for other structures that are not pits (e.g., detecting leaks under a road), it still would need to redefine this term because as is, the draft defines a leak detection system as "[a] system used to detect leaks below the liner of ***pits***[.]"

(58) *"Natural gas or natural gas liquids processing plant"*

[95] Ex 25 Process Ponds. Figure 1. https://ndep.nv.gov/uploads/land-mining-faq-docs/Process_Ponds.pdf

[96] For example, would the Commission allow a mass-balance approach to monitoring the contents of a pit, and if so, how would the operator keep track of the inputs (flow rates, volume per depth, evaporation, rainfall, etc.) that would be accurate enough to detect a loss of liquids not otherwise accounted for in the process?

"Natural gas or natural gas liquids processing plant" is a new definition from current SWR8 and has been revised during drafting. It now also includes plants whose "primary function" includes "the production of pipeline-quality gas for transportation by a natural gas transmission pipeline." This term is only cited in delineating the activities that the Commission regulates. Commission Shift requests clarity on why this definition has changed and whether this changes who regulates these plants.

(60) *"non-commercial fluid recycling"*

Commission Shifts requests that the Commission clarify with examples what type of recycling operations would qualify as non-commercial. As written, it appears that non-commercial use would extend to any sort of fluid recycling done as long as it was on ***land*** associated with a drilling permit, no matter the magnitude of the operation or if money was exchanged. It would also extend to recycling on ***land*** where a non-commercial disposal or injection well was owned. But neither of these categories explain ***how*** the fluid is to be recycled. It's also unclear why the definition in part (2)(B) mentions both "a person" and wholly-owned subsidiaries—that would appear to be redundant given that 4.110(69) defines persons to include corporations and "any other legal entity." Moreover, Commission Shift is concerned that what would appear to be a commercial transaction (contracting to accept fluid from other leases or persons) would be treated as non-commercial under these rules. Also confusing about this definition is the fact that (76) "recycle" excludes injection pursuant to a permit issued under §3.46, yet the non-commercial definition incorporates land used for the purposes of operating a §3.46-permitted well.

(67) *"operator"*

Commission Shift requests clarity why "operator" is being defined for the first time—operator is not defined in the current SWR8—and why the following definition was chosen:

> A person, acting for itself or as an agent for others, designated to the Railroad Commission of Texas as the person with responsibility for complying with the rules and regulations regarding the permitting, physical operation, closure, and post-closure activities of a facility regulated under this chapter, or such person's authorized representative.

Commission Shift suggests that the list of activities "permitting, physical operation, closure, and post-closure" be broader, e.g., to include construction, maintenance, and management activities.

(80) *Small sump*

Feedback from communities struggling with poorly managed waste facilities in their backyards strongly suggest that a single foot of freeboard on a sump is insufficient to prevent spills and has been a source of stormwater contamination. Sumps should be required to have an automatic sump pump that maintains the level of liquid below the freeboard height.

(88) "Waste management unit"

"Waste management unit" now includes in its definition a "container," which is defined to include pits. As part of its rulemaking, the Commission should provide examples as to what is and is not included as a waste management unit so that the regulated community and the public can better understand the scope of these regulations.

(90) "*washout pit*"

Commission Shift notes that "washout pit" is never used elsewhere in Subchapter A. Commission Shift requests the Commission's confirmation that such a pit would need to apply for a permit because it is not one of the enumerated "authorized" operations listed in Division 3.

(93) *wetland*

Commission Shift suggest that the Commission include in this definition the proper way to assess whether a wetland is in fact a wetland—by using National Wetlands Inventory (NWI) maps or through an onsite wetlands determination. Applicants and operators should be required to assume that wetlands are present when indicated on NWI maps, unless an onsite determination shows otherwise. The definition in §4.110(93) should be revised to state that a wetland is:

> Wetland--An area including a swamp, marsh, bog, prairie pothole, or similar area having a predominance of hydric soils that are inundated or saturated by surface or groundwater at a frequency and duration sufficient to support and that under normal circumstances supports the growth and regeneration of hydrophytic vegetation. The term "hydric soil" means soil that, in its undrained condition, is saturated, flooded, or ponded long enough during a growing season to develop an anaerobic condition that supports the growth and regeneration of hydrophytic vegetation. The term "hydrophytic vegetation" means a plant growing in water or a substrate that is at least periodically deficient in oxygen during a growing season as a result of excessive water content. The term "wetland" does not include irrigated acreage used as farmland; a man-made wetland of less than one acre; or a man-made wetland for which construction or creation commenced on or after August 28, 1989, and which was not constructed with wetland creation as a stated objective, including but not limited to an impoundment made for the purpose of soil and water conservation which has been approved or requested by soil and water conservation districts (Texas Water Code §11.502.). <u>Wetlands are to be presumed present onsite if so indicated by an NWI map, unless an onsite wetlands determination concludes otherwise.</u>

3. <u>DIVISION 3 OPERATIONS AUTHORIZED BY RULE</u>

Commission Shift reiterates its position that once a facility qualifies as commercial, ***every*** waste management unit on the property must be permitted. In other words, pits and sumps that might otherwise be permitted-by-rule under Division 3 (for example if they were located at the drill site) should not be allowed to be permitted by rule if they are part of a commercial facility. It is too confusing for the public and regulators to have both permitted and "authorized" activities at the same property and could tempt bad operators to use "authorized" operations to circumvent the notice that goes along with permitting (and subsequent review).

§4.111. Authorized Disposal Methods for Certain Wastes, Page 18

In a previous draft of this rule, the Commission proposed requiring explicit surface owner consent prior to disposal authorized by rule (i.e., without a permit). That language has been removed in this draft, after some members of industry objected.[97] The Commission was right to have included that language initially and should not bow to industry pressure to have that language removed. Indeed, other members of industry have supported adding that language back in, pointing out that Texas is one of the *only* states that does not require landowner permission prior to disposal.[98] The Commission should add it back in as subsection(a) as follows:

> §4.111 (a) Surface owner informed consent. All authorized disposal requires the written consent of the surface owner of the property on which the disposal will occur. Without surface owner consent, oil and gas waste shall be removed from the property and disposed of in an authorized manner.
>
> (1) The operator shall inform the surface owner in writing that disposal authorized under this section may not necessarily meet the requirements of TCEQ's Texas Risk Reduction Program (30 Texas Administrative Code Chapter 350) regarding protective concentration levels for residential or commercial land use, or other land use restrictions.
>
> <u>(2) The operator shall inform the surface owner in writing of the type and quantity of waste to be disposed of onsite and the duration during which disposal will occur.</u>[99]
>
> ~~(2)~~ <u>(3)</u> The operator shall obtain written consent from the surface owner authorizing disposal on the property.

Other edits to § 4.111 include the following:

Commission Shift is concerned that constituents beyond BTEX may be present in water condensate, and thus urges the Commission to test additional parameters beyond those in Figure 16 TAC §4.111(a) (Page 85). Water condensate may also have other residual chemicals from hydraulic fracturing, fracturing flow back, and other formation liquids that could end up in the water condensate. In addition, the fact that this waste is often land applied on agricultural lands makes

[97] Compare Ex. 15, Excerpt of May 2023 Subchapter A Draft (§ 4.111) (highlights in original) with Ex. 16, Permian Basin Petroleum Association Comments (June 6, 2023) at 2; with proposed § 4.111.

[98] Ex. 26, Milestone Comments, at 1. Milestone (operator of commercial disposal sites) explains: "Reserve pits are often large, de facto mini-landfills capable of storing hundreds to thousands of barrels of waste (see Figure 1). Texas landowners should be afforded the right to decide whether their land is used for this purpose because permanent disposal includes potential financial, environmental, and health risks for the landowner. Therefore, obtaining consent prior to permanent burial not only protects the landowner, it also protects the operator, the Railroad Commission, and ultimately Texas taxpayers from bearing the burden of future financial liability and remediation costs."

[99] This aligns with the notifications required in Louisiana, which include: a detailed explanation of the method(s) used to generate the waste material, including types and volumes of the additives used, amounts of waste material generated…and written approval from the surface owner of the property where the processed material is to be applied, and any other pertinent information required by the Commissioner. La. Admin. Code title 43 § XIX-313(G).

testing for constituents that can cause adverse effects on crops[100] and livestock[101] all that more important. Testing for TPHs as well as BTEX should be required at a minimum. Operators should also be required to test for the traditional suite of general water quality parameters including: pH, Electrical Conductivity, Total Dissolved Solids (measure of salinity), Chlorides, Volatile Organic Compounds (VOCs), and Total nitrogen.[102] Testing for hazardous compounds should include: BTEX, PAHs[103] and NORM.[104]

Subsection (a)(5) of the draft also should be revised so that adjacent surface owner consent is required if the water condensate ***may*** leave the property, not only if only if it "will."[105] The

[100] Ex. 27, Application of Water-base Drilling Mud to Winter Wheat: Impact of Application Timing on Yield and Soil Properties. https://extension.okstate.edu/fact-sheets/application-of-water-base-drilling-mud-to-winter-wheat-impact-of-application-timing-on-yield-and-soil-properties.html (describing how the application of water based mud to winter wheat fields resulted in high electrical conductivity in the top soil at a level detrimental to most plants, including their germination rates. Contamination rates only decrease after 6 inches of rainfall—rates much higher than those in much of the state). See also Ex. 28 https://twon.tamu.edu/wp-content/uploads/sites/3/2021/06/irrigation-water-quality-standards-and-salinity-management-strategies-1.pdf (explaining how soils with high levels of total salinity can simulate drought conditions for the root zone even if the soil appears to have plenty of moisture)

[101] West Texas in particular has a significant population of dairy cows, which can be adversely affected by the contaminants in water condensate. See Ex. 29 Interpreting Drinking Water Tests for Dairy Cows https://extension.psu.edu/interpreting-drinking-water-tests-for-dairy-cows "Levels above 3,000 mg/L are more likely to cause poor tasting water that may result in reduced water intake and milk production again depending on the exact pollutants causing the high TDS concentration. Overall, water with a TDS above 1,000 mg/L has the potential to cause livestock problems[.]" . . . "Chlorides above 250 mg/L can impart a salty taste to water which could result in reduced water intake and milk production . . . High chlorides should also be considered when formulating diets to prevent an excess which could be detrimental to rumen function . . . Sulfate concentrations below 1,000 mg/L are generally thought to be safe for adult animals but some authors have suggested limits as low as 500 mg/L."

[102] Monitoring for TDS, Chlorides, VOCs and Total nitrogen identifies what else is in the water condensate that might adversely impact crops and livestock (besides being a potential threat to shallow groundwater).

[103] According to the EPA, PAHs can constitute 20 to 60 percent of diesel fuel, which has not been prohibited as an additive to hydraulic fracturing fluid, making it a possible contaminant of water condensate. See Ex. 30 EPA Study at 5-6. https://www.epa.gov/sites/default/files/2015-05/documents/revised_dfhf_guid_816r14001.pdf; see also RRC Hydraulic Fracturing website. https://www.rrc.texas.gov/about-us/faqs/oil-gas-faq/hydraulic-fracturing-faqs/ ("Commission regulations do not prohibit the use of diesel fuel in hydraulic fracturing activities. Such use would not be a violation of Commission rules, unless the operator caused or allowed pollution during such use, of which there is no evidence.") Diesel fuel may also be used a component in drilling muds—another source of contamination for water condensate. Ex. 30 EPA Study at 7.

[104] The Commission has recognized that NORM can be a problem in produced waters and natural gas if it gets concentrated, as condensate does. https://www.rrc.texas.gov/oil-and-gas/applications-and-permits/environmental-permit-types/norm-waste/ (""Because the levels are typically low, **NORM in produced waters and natural gas is not a problem in Texas unless it becomes concentrated**. Through temperature and pressure changes that occur during oil and gas production operations, Radium 226 and 228 found in produced waters may co-precipitate with barium sulfate scale in well tubulars and surface equipment. Concentrations of Radium 226 and 228 may also occur in sludge that accumulates in oilfield pits and tanks. These solids become sources of oil and gas NORM waste**. In gas processing activities, NORM generally occurs as radon gas in the natural gas stream. Radon decays to Lead-210, then to Bismuth-210, Polonium-210, and finally to stable Lead-206.** Radon decay elements occur as a film on the inner surface of inlet lines, treating units, pumps, and valves principally associated with propylene, ethane, and propane processing streams.") See also EPA TENORM https://www.epa.gov/radiation/tenorm-oil-and-gas-production-wastes (explaining how an API industry-wide survey showed that "TENORM radioactivity levels tend to be highest in water handling equipment," at an average level "about five times background.")

[105] "(5) the water condensate is applied to the ground surface in such a manner that it will not leave the boundaries of the property; or, if it is applied such that it ~~will~~ may leave the property and enter an adjoining property, the operator has obtained written permission from the surface owner of the adjoining property;"

Commission—and therefore operators—have a duty to be proactive in preventing pollution, as the Commission recognized in 1984:[106]

> Whether or not an activity actually causes pollution can only be determined after the pollution has occurred. The commission has the duty to prevent pollution, and therefore must regulate activities which might result in pollution.

Subsection b. Commission Shift requests that the Commission clarify whether disposal of inert oil and gas wastes in (b) would be allowed by other potentially dangerous means, such as burning (which should not be allowed).

Subsection c. Subsection (c) raises a concern Commission Shift has throughout this rulemaking. Subsection (c) uses the chloride concentration of a waste as a proxy for toxicity and potential harm to groundwater and the environment.[107] However, drinking water is regulated using total dissolved solids, which captures the chloride content but also other dissolved ions.[108] Even electrical conductivity is another proxy that would capture additional constituents of concern to human, animals, and the environment.[109] (And indeed, the May draft of Subchapter A used electrical conductivity instead of chloride).[110] Commission Shift requests that the Commission explains why it believes that chloride content is the appropriate proxy for regulation of oil and gas waste; Commission Shift suggests that both chloride and electric conductivity limits be set on waste.

Also in subsection (c), Commission Shift objects to the idea that the District Director could approve a greater slope for landfarming. Leaving this decision up to the Districts removes transparency from the process and makes it more difficult to track whether such decisions were appropriate to avoid pollution and protect human and environmental health. Section (c)(3) should be revised as follows:

> the slope of the area to be landfarmed is three percent or less~~, or any greater slope is approved in writing by the District Director~~;

Subsection d. As for subsection(d), in a previous draft the operator would have been required to test the waste prior to burial.[111] Commission Shift requests that the Commission clarify if this requirement was removed as redundant because testing would already be required under 4.114. If not, Commission Shift urges the Commission to add the testing requirement back in.

Subsection e. Commission Shift notes that when subsection (e)(4) states that documentation of closure requirements for completion / workover pits should be filed with the Commission, that

[106] 9 TexReg 1550 (March 16, 1984) (rejecting the suggestion that the Commission regulate only activities that affirmatively cause pollution).
[107] It is also used as a proxy in § 4.115(b),(d), § 4.162 and in Figures 16 TAC § 4.114(f) and (g).
[108] The Texas Water Development Board defines water quality based on total dissolved solids. https://www.twdb.texas.gov/innovativewater/desal/faq.asp#title-02
[109] Electrical of conductivity of less than 4 mmhos/cm could be a more appropriate threshold.
[110] Ex. X5 May Draft at 79 (Figure §4.114(e)(1)(D)) (copying Louisiana regulations).
[111] Stating that "The disposal [of other drilling fluid] is authorized provided: . . . the waste meets the analytical requirements in the Figure in §4.114(e)(1)(D) of this title." Ex. 15 May Draft at 19, 79.

documentation should also be made publicly available, not simply maintained available upon request. (See comments on § 4.108).

As for the setbacks proposed in this section, Commission Shift has consolidated its comments on setbacks to its discussion of § 4.150.

§4.112. Authorized Recycling. Page 21

In May, the Commission proposed requiring that operators "register[] the location of buried pipelines connecting non-commercial fluid recycling pits within 30 days of the pipelines entering service after the Director has established a registration system."[112] Given that these pipelines can also be sources of pollution, the Commission and future operators should at a minimum be advised of their location, just as authorized pits will now be required to be registered. Commission Shift supports adding this registration requirement back in.

Also removed from the May draft was the requirement that "Fluid recycling pits that do not meet the definition of non-commercial fluid recycling pits and are not commercial pits shall be permitted pursuant to Divisions 4 and 6 of this subchapter."[113] This appears to have been removed in favor of a more vague "miscellaneous" permitting scheme in Division 9 that would ignore Divisions 4-8 (see Commission Shift's comments on Division 9, below). Commission Shift objects to allowing for the miscellaneous permitting schemes of Division 9 which would allow new permitting schemes be created without notice-and-comment rulemaking.

Commission Shift requests that documentation envisioned in (c) be forwarded to the Commission and made public, consistent with Commission Shift's earlier comments in § 4.108.

§4.113. Authorized Pits. Page 22

Commission Shift reiterates its opinion that no authorized pits should be allowed on the same property as a commercial facility—all waste management units described in § 4.113(a) (including small sumps) should be applied for and permitted. This could be effected by modifying (a) as follows:

> (a) Unless such waste management units are located on the same property as a commercial facility, a~~A~~n operator may, without a permit, maintain or use a reserve pit, mud circulation pit, completion/workover pit, fresh makeup water pit, fresh mining water pit, water condensate pit, non-commercial fluid recycling pit, or small sump. If such waste management units are located on the same property as a commercial facility, they must be permitted. Authorized pits are required to comply with the applicable requirements of §4.114 of this title (relating to Requirements Applicable to All Authorized Pits), and §4.115 of this title (relating to Specific Requirements Applicable to Authorized Pits). Authorized pits may be subject to certain additional containment guidelines at the Director's discretion based on factors such as the characteristics of the pit location.

[112] Ex. 15 May draft at 20.
[113] Ex. 15 May draft at 20 (4.112(b)(2)).

Commission Shift also understands this proposed rule to allow the vast majority of pits that were authorized under Rule 8 to be grandfathered in and not need to comply with these new rules (except for rules on closure, see (b)(3)). This runs counter to the idea that this rule will improve environmental and human health. Subsection (b) should be modified to require that all authorized pits—not just the ones that cause pollution—must become compliant with the new rules or be closed:

> An authorized pit that was constructed pursuant to and compliant with §3.8 of this title (relating to Water Protection) as that rule existed prior to [insert effective date of this rulemaking], is authorized to continue to operate subject to the following:
>
>> (1) Authorized pits ~~that cause pollution~~ shall be brought into compliance with this subchapter or closed according to this division.
>>
>> (2) By [insert one year after the effective date of this rulemaking], basic sediment pits, flare pits, water condensate pits, and other unpermitted pits not authorized by this section shall be: (A) permitted according to this subchapter; or (B) closed according to this division.
>>
>> (3) At the time of closure, authorized pits shall be closed according to this division.

Regardless, the Commission should also clarify that a pit originally authorized under the prior Rule 8 would need to comply with the updated rules if it was redesignated to be a different pit type, as contemplated in 4.114(a)(6).[114] Otherwise, a loophole might exist in that an operator could continue to redesignate pit types based on the prior Rule 8 as long as the footprint of the pit pre-dated the rule updates.

Commission Shift is also concerned that subsection (c) does not require immediate action by an operator in the event of a release. Commission Shift urges the Commission to incorporate the language used in Division 10 as follows:[115]

> (c) In the event of an unauthorized release of oil and gas waste, treated fluid, or other substances from any pit authorized by this section, the operator shall take immediate corrective action and any measures necessary to stop or control the release and report the release to the District Office within 24 hours of discovery of the release.

[114] § 4.114(a)(6) "An authorized pit may be designated as more than one type of pit provided it meets the requirements in this section for each type of pit. An authorized pit of one type may be redesignated as an authorized pit of another type (for example, a reserve pit may be redesignated as a completion pit) provided the pit was constructed to meet the more stringent design and construction requirements, and the operator notifies the District Director of the redesignation pursuant to the procedure described in paragraph (5) of this subsection."

[115] Compare with § 4.196(b)(7) "Immediate corrective action shall be taken in all cases where pollution has occurred. An operator responsible for the pollution shall remove immediately such oil, oil field waste, or other pollution materials from the waters and the shoreline where it is found. Such removal operations will be at the expense of the responsible operator." The Commission should also reiterate that all other responsibilities in (b)(7) apply to operators of authorized pits.

§4.114. Requirements Applicable to All Authorized Pits, Page 22

Subsection a. Commission Shift supports the creation of a registration system for all authorized pits (as in 4.114(a)(5)) and encourages the Commission not to delay in establishing such a publicly-accessible registration system.[116] Commission Shift suggests that the rules should be amended to set a time limit on the Commission to establish such a registration system by adding as a final sentence to § 4.114 (a)(5):

> "The Director shall establish a registration system for authorized pits by [insert one year after the effective date of this rulemaking]."

Commission Shift also urges the Commission to require pits be registered within 30 days of the registration system becoming available—registration simply requires the operator to report data that it should already have. Allowing a full year to elapse before registration is required is excessive. As such, Commission Shift recommends that § 4.114(a)(5)(B) be amended as follows:

> (B) Pits existing at the time the registration system is established shall be registered or closed within 30 days ~~one year~~.

The registration should also ask operators to include the following information, all of which should be readily available to operators. These additional requests could be appended to § 4.114(a)(5)(C) as follows:

> (v) the history of the pit: when it was constructed, if and when it has changed type (as envisioned by § 4.114(a)(6);
>
> (vi) the construction methods, including as-built diagrams, liner materials, and leak detection systems (if any);
>
> (vii) the compliance inspection frequency (as set in § 4.114(d)(3)); and
>
> (viii) how closure sampling will be conducted (e.g., background vs. regulatory limits set in § 4.114(f)(3)(A) or § 4.114(g)(3)(A)).

It also appears that there is a typo in section (a)(6), which directs operators to notify "the District Director of the redesignation pursuant to the procedure described in paragraph (5) of this subsection." Paragraph (a)(5) does not reference the District at all—perhaps the Commission meant to require that the operator reregister the pit (the final clause of (a)(6)):

> the operator ~~notifies the District Director of the redesignation~~ reregisters the pit pursuant to the procedure described in paragraph (5) of this subsection

Subsection b.

Commission Shift strenuously objects to the idea that operators can request exceptions of setbacks. As proposed, the public would have no notice or opportunity to participate in the review of exceptions requested by authorized pits and no guidelines have been given as to what information

[116] Commission Shift understands that the Commission's guidance sates that authorized pits must be registered with the appropriate RRC District Office, but does not see evidence of a registry online. https://www.rrc.texas.gov/media/rouciyfm/section_j.pdf#page=18 "Authorized pits, listed under SWR 8(d)(4), do not require an individual permit, but must be registered with the appropriate RRC District Office."

the Commission would consider when deciding whether an exception to a setback is appropriate. Commission Shift fears that exceptions would be routinely granted, with no system in place to monitor whether such an exception ultimately caused pollution or endangered human and environmental health. Especially since the District Directors, and not Technical Permitting staff in Austin that make this decision, where there might be some centralization and tracking of this information across districts. Subsection b should be revised to prohibit exceptions for authorized pits. As for the setbacks proposed in this section, Commission Shift has consolidated its comments on setbacks to its discussion of § 4.150.

Subsection c. Commission Shift is concerned that § 4.114(c)(3) could inadvertently allow authorized pits to be constructed in highly permeable soils because it includes no limitation on the soil type. Commission Shift suggests that § 4.114(c)(3) be modified to require a 2-foot section of low permeability material (1.0 x 10^{-7} cm/sec or less) be required within those 20 feet such that subsurface water will be protected:

Commission Shift also notes that the instructions on constructing natural liners (§ 4.114(c)(6)(D)) do not mention ensuring that the lifts are properly joined together such that there are no preferential pathways for leaks at the interconnections. The Commission should add language specifying the need to ensure each lift is properly seated to avoid such failure routes and in additional require operators to request and retain the QA/QC documentation provided by liner installers for three years after the pit has been closed.[117] Liner installers that do not already have QA/QC procedures should be directed to the Commission's CQC forms or those used by TCEQ for liner installation.[118] QA/QC documentation should also be required and retained when synthetic liners are used (as described in § 4.114(c)(6)(E)). Commission Shift interprets § 4.114(a)(4)[119] to already require that the operator maintain such QA/QC documentation, but if that is not the case, the Commission could modify (E) as follows:[120]

> (E) A synthetic liner shall meet the following requirements<u>, and the operator shall maintain documentation demonstrating these requirements have been met. The operator shall maintain these records for at least three years from the date of closure and provide copies of these records to the Commission upon request</u>:

[117] Many liner installers already have internal QA/QC procedures as well. E.g., Ex. 31 GeoChem. Field Installation Quality Assurance Manual. https://www.geocheminc.com/pdf/GeoCHEM-Field-Installation-QC.pdf;

[118] Ex. 23 Municipal Solid Waste Facility Geomembrane/Geosynthetic Liner Evaluation Report. https://www.tceq.texas.gov/downloads/permitting/waste-permits/msw/forms/10070.docx (describing how "This liner evaluation report is required to document that the liner was constructed as designed in accordance with the issued registration or permit and meets the TCEQ regulatory requirements prior to unit operation. This report is to be supplemented with those quality-assurance/quality-control (QA/QC) tests as detailed in the liner quality control plan (LQCP) and shall be the basis of documentation of the quality control and acceptance of the constructed liner.").

[119] "The operator shall maintain documentation demonstrating compliance with §4.113 of this title (relating to Authorized Pits), this section [§4.114], and §4.115 of this title (relating to Specific Requirements Applicable to Authorized Pits) for at least three years from the date of closure of the authorized pit. The operator shall provide copies of these records to the Commission upon request."

[120] This language is intended to mirror the language the Commission has already proposed in this rulemaking.

Commission Shift has additional feedback on the synthetic liner requirements found in § 4.114(c)(6)(E). As an initial matter, it is difficult for the public to provide meaningful feedback on the ASTM methods cited in this section (and elsewhere throughout the rule) because ASTM methods are often behind a paywall online. The Commission should endeavor to provide the public a summary of the important aspects of each ASTM Method during the formal comment period so that the public is not at a disadvantage when providing comments.

Commission Shift was able to identify some publicly available information about ASTM D882, which is referenced in § 4.114(c)(6)(E)(v). ASTM D882 is only to be used for liners less than 1 mm (40 mil) thick; for thicker liners, ASTM D638 is recommended.[121] The Commission should revise § 4.114(c)(6)(E)(v) accordingly and also confirm that it has set a minimum thickness for authorized pit liners to be 40 mil:[122]

> (iv) A synthetic liner shall have a breaking strength of 40 pounds per inch using test method ASTM D882 <u>or ASTM D638, as appropriate</u>.

Subsection f (and Figure: 16 TAC §4.114(f). Page 86.) Commission Shift suggests that confirmation sampling for closure not mix sidewall samples with pit bottom samples as envisioned in (f)(3) (“the five-point sample”). If the pit had leaked, the bottom would be expected to be more contaminated than sidewalls (since the pit may not always have been full). Thus confirmation sampling should sample the pit floor separate from sidewalls.

Commission Shift is also concerned whether true background can be determined (as contemplated in subsections f and g), given the density and intensity of drilling in Texas. Because of the drilling density in Texas, clean up standard should be set to prescribed levels, not background. Commission Shift joins operators like Milestone[123] in requesting this change: normally, “background concentrations” means native soil, in its naturally occurring state. However, as currently drafted, “background concentrations” could also include soil that has been highly contaminated by prior waste disposal (or spills) because there are no prescribed concentration limits associated with “background concentrations” and because there is no definition of “background concentrations”.

[121] Ex. 32 ASTM D882. Standard Test Method for Tensile Properties of Thin Plastic Sheeting. https://www.micomlab.com/micom-testing/astm-d882/ (“ASTM D882 is used to measure tensile properties including ultimate tensile strength, yield strength, elongation, tensile energy to break and tensile modulus of elasticity of thin plastic sheeting and films. The samples are cut in strips that minimally have to be eight times longer than wide. No dumbbell shape is cut for materials of that thickness. Cut samples need to be free of nicks and other cutting defects since they will have an important impact on the test results variation. The samples are tested in specific conditions of pre-treatment, sample orientation, temperature, humidity, and rate of pulling. ASTM D882 can be used for testing materials thinner than 1mm in thickness. Thicker materials should be tested using ASTM D638.”)

[122] The Commission should consider including a table similar to ones offered by USDA and other agencies one so that operators know how thick a liner needs to be depending on the material it is made of (HDPE, LLDPE, PVC, etc). See Ex. 33 Natural Resources Conservation Service. Conservation Practice Standard. Pond Sealing Or Lining, Geomembrane Or Geosynthetic Clay Liner. https://efotg.sc.egov.usda.gov/api/CPSFile/84/521_TX_CPS_Pond_Sealing_or_Lining%2c_Geomembrane_or_Geosynthetic_Clay_Liner_2018 at 1-2 (specifying thickness based on liner type).

[123] Ex. 26 (Milestone comments) at 2-3.

Therefore, an operator could permanently bury new waste at the highly contaminated levels because those highly contaminated levels are the "background concentrations". This would result in an increased likelihood of pollution to groundwater, which is antithetical to the purpose of New Chapter 4, Subchapter A.

If background sampling is allowed, at a minimum a certified professional (e.g., a professional geologist) should be involved in closure in order to ensure that background levels are calculated correctly and are truly representative of background.

Commission Shift also requests that the Commission explain how an operator would comply with the requirement in (f)(5) that allows burial-in-place of waste if "the operator demonstrates the liner is intact ***and*** maintains the liner intact."[124] §§ 4.114(f)(5)(A) and (g)(5)(A). Commission Shift is aware of in-situ testing methods that could be used to test the integrity of a synthetic liner[125]—the Commission should clarify if this is what is envisioned. Additionally, the Commission should also explain how the operator will ensure that the liner is maintained intact (or that leaks do not overwhelm the leak detection system, as in (f)(5)(A)(i)). Commission Shift recommends that the Commission require at post-closure monitoring program of at least 10 years if the waste is left in place so that operators ensure that no leaks develop after the waste has settled and after the pit has had the opportunity to weather a wide range of weather events.[126] This should be required for both authorized and permitted facilities.

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[124] 4.114(f)(5) Untreated waste material that does not meet the constituent limits in the Figure in subsection (f) of this section:

(A) may be buried by containment in a pit that:

(i) has a double liner with a leak detection system; or

(ii) has a single liner for which the operator demonstrates the liner is intact and maintains the liner intact;

[125] Synthetic liner testing with electrodes is a service offered by liner companies in Texas. *E.g.*, TRI Environmental (offices in Austin) https://tri-environmental.com/electrical-leak-location-services/; Mustang Extreme Environmental Services (offices in the Permian Basin) https://mustangextreme.com/about/our-history/ (stating that as of 2019 Mustang Extreme Environmental Services installed over 1.0 billion square feet of liner) (note that Commission Shift is not necessarily endorsing the quality of service provide by these companies). There are also ASTM standards for using electrical methods for locating leaks in geomembranes that the Commission could explore adopting. E.g., ASTM Standard D6747 (2004), "Standard Guide for Selection of Techniques for Electrical Detection of Potential Leak Paths in Geomembranes," https://www.astm.org/d6747-21.html; ASTM D7007-16 "Standard Practices for Electrical Methods for Locating Leaks in Geomembranes Covered with Water or Earthen Materials." https://www.astm.org/d7007-16.html; ASTM D8265-21 (2021), "Standard Practices for Electrical Methods for Mapping Leaks in Installed Geomembranes" https://www.astm.org/d8265-21.html; ASTM D7002-22 (2022), Standard Practice for Electrical Leak Location on Exposed Geomembranes Using the Water Puddle Method. https://www.astm.org/d7002-22.html See also Ex. 34 2000 Nosko and Touze Geomembrane liner failure Modelling of its Influence on Contaminant Transfer. https://www.researchgate.net/publication/258000268_Geomembrane_liner_failure_modelling_of_its_influence_on_contaminant_transfer (describing damage detection systems, noting how "the majority of damage were caused by stones within the protection layer and heavy equipment" and that "most failures were located within flat areas").

[126] In comparison, hazardous waste landfills and Class 1 and Class 2 nonhazardous landfills typically require a monitoring period of 30 years. TCEQ Draft Technical Guideline No. 10 at 4-5 (Revised Dec. 7, 2017) https://www.tceq.texas.gov/downloads/permitting/waste-permits/ihw/docs/tg10.pdf

Subsection g. (Figure: 16 TAC §4.114(g). Page 87) Commission Shift strenuously objects to the theory that "dilution is the solution to pollution" adopted in § 4.114(g)(2) which would allow clean soils to be mixed with wastes in order to lower the concentration of pollutants:[127]

> (2) The operator shall stabilize or solidify the remaining authorized pit contents to a physical state sufficient to support the final cover of the authorized pit. **The operator shall not mix the remaining pit contents with soil or other material at a mixing ratio of greater than 3:1, soil or other material to remaining pit contents.** The resulting waste mixture must pass the paint filter liquids test (EPA SW-846, Method 9095).

Commission Shift expects operators and industry to argue that the dilution prohibition applies only to what is legally defined to be hazardous waste. Even if dilution is technically not prohibited, it is widely irresponsible policy to allow clean soils of Texas to become polluted in this manner. The Commission should unequivocally prohibit operators from using soils or other materials to lower the concentration of pit contents. If the contents of a pit are too polluted, then the wastes should not be buried in an authorized pit—they should be disposed of in a permitted landfill.

The paint filter test also is inappropriate here. The Paint Filter test determines whether liquid will leak out of a material within five minutes. It says nothing about whether pollutants will continue to leach out of the waste if the material is rewetted by precipitation.

As for the closure procedures described in (g)(7)(C)-(D) and (f)(3)(D)(iii)-(iv), Commission Shift suggests that the Commission provide additional guidance as to the maximum slopes allowed at the former pit site and consider incorporating its existing guidance on revegetation and erosion controls from its surface mining rules.

Finally, for ease of readability, Commission Shift requests that before the Commission publishes these rules for formal comment, the Commission refer to Figures (g) and (f) by their full names instead of "the Figure in this subsection."

Subsection h. There are several improvements that can be made to subsection (h), which describes groundwater monitoring requirements for authorized pits. Commission Shift is opposed to the leniency on groundwater monitoring introduced in subsections (h)(1)-(3).[128] This section was stronger (and less open to multiple interpretations) in a previous version of this rulemaking that Commission Shift obtained through a Public Information Act request—Ground water monitoring requirements for authorized pits were relaxed after the Permian Basin Petroleum Association sent its

[127] To be clear, Commission Shift advocates for the bold language to be stricken from the rule.
[128] Additional specific problems include that Commission has not defined what acceptable "readily available public information" may be used to determine if groundwater is likely to be present within 100 feet of ground surface. Applicants should review local water well permits and driller's logs in the immediate vicinity, the presence of groundwater management areas, USGS, and survey nearby residents. In addition, the absence of any water wells within 100 feet does not show that there is not any groundwater within 100 feet—subsurface water of smaller quantities and quality may still be present near the surface.

complaints to the Commission.[129] Commission Shift urges the Commission to return to the language in the May draft which would require monitoring wells be installed for **all** authorized pits that do not have a leak detection system. That language, which Commission Shift supports to replace parts (1) – (4) subsection h, is:[130]

> *(h) Groundwater monitoring requirements for authorized pits.*
>
> > *(1) Groundwater monitoring is required for authorized pits that do not have a* ***double synthetic liner with a operational*** *leak detection system.*
> >
> > *(2) An authorized pit with an active life of more than one year shall have at least three groundwater monitoring wells, at least two of which are installed in a* ***hydrologic*** *downgradient location and one of which is installed in an upgradient location relative to the pit.*
> >
> > *(3) An authorized pit with an active life of less than one year shall have at least one groundwater monitoring well that is installed downgradient to the pit.*
> >
> > *(4) Groundwater monitoring wells shall be sited, installed, and constructed according to §4.131 of this title (relating to Monitoring Standards).*

As for subsection (h)(5), Commission Shift is generally encouraged by the level of specificity required in the well construction. It should be made clearer though that static water level should be measured during every sampling event and a potentiometric surface map created for every event: as is, the retention requirements set in (h)(5)(J)(iv)-(v) do not clarify this information must be developed for each and every sampling event—compare this to the language in (vi), which does specify record retention of reports and chains of custody "from each groundwater sampling event." All of the data developed and required to be retained in (J) should also be made publicly available contemporaneously—in particular, the results from each sampling event should be filed electronically with the Commission and public promptly after each sampling event. Without concurrently sharing this information with the Commission and public, the operator is the only one reviewing whether "potential pollution" is indicated (the standard in (h)(8)). Just as the Commission requires that operators use independent labs to conduct the sampling analysis (see section 4.124(e)(3)(A)), an independent reviewer should be the one assessing if pollution has potentially occurred—not the operator itself. The sample collection itself should also be conducted by independent samplers neither owned nor operated by the pit operator. This is already recognized practice in Louisiana.[131]

Commission Shift also urges the Commission to modify (h)(5)(A) to require continuous collection of soil samples, not simply "periodic." Periodic soil sampling skips over whole intervals of the subsurface—areas where subsurface water may be present. It is impossible for operators to identify

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[129] Compare Ex. 15, Excerpt of May 2023 Subchapter A Draft (§ 4.114(f)) (highlights in original) with Ex. 16, Permian Basin Petroleum Association Comments (June 6, 2023) at 2; with proposed § 4.114(h).

[130] Bold is additional language that Commission Shift believes would add clarity.

[131] "Sampling and testing must be performed by an independent professional consultant and third-party laboratory." 43 La. Admin. Code Pt XIX, 517

"the shallowest groundwater zone" (as required by (h)(5)(C)) and to ensure that they are not "caus[ing] or allow[ing] pollution of surface or subsurface waters in the state" without collecting the soil samples that would indicate the presence of subsurface waters. A desktop review of TWDB and TCEQ does not suffice. As such, § 4.114(h)(5)(A) should be modified as follows:

> (5) The following is required for each soil boring or groundwater monitoring well drilled.
>
> (A) The drilling method shall allow for ~~periodic or~~ continuous collection of soil samples for field screening and soil characterization in order to adequately characterize site stratigraphy and groundwater bearing zones.

Subsection (h)(7) should also be amended to include sampling for any additional parameter that the Director deems necessary, including BTEX (not just benzene). Commission Shift also supports amending (h)(6) to allow for sampling on a more frequent schedule than only quarterly, if the Director deems it necessary (e.g., in the event of suspected pollution or other problems). The Commission included such language in 4.131(b)(4)(D), which should be incorporated into 4.114(h)(8) with the following modifications:

> If any of the parameters identified in paragraph (h)(7) of this subsection indicate potential pollution, or the potential failure of the liner system: (A) the operator shall notify the ~~District~~ Director by phone or email within 24 hours of receiving the analytical results; ~~and~~ (B) the ~~District~~ Director will determine whether additional remediation, monitoring, or other actions are required; and (C) in the meantime, the operator shall be prohibited from accepting additional waste at the pit until the pit no longer is a source of potential pollution.

§4.115. Specific Requirements Applicable to Authorized Pits, Page 32

Commission Shift understands section 4.115 to add additional requirements to certain authorized pits, yet notes there seem to be a number of internal inconsistencies as drafted.

Section 4.115(2)(A) allows reserve pits or mud circulation pits to be constructed in alluvium or Quaternary sand and gravel. No pit should be constructed in such strata, even with a liner. The presence of alluvium or Quaternary sand and gravel are known to be associated with surface water systems and thus indicate that the area is in a potential floodplain of a surface water system. It also is a highly permeable soil type. Waste that leaks out could migrate both unpredictably and much faster than waste leaked into soils with lower permeability and thus pose an unacceptably greater risk to water quality.

Section 4.115(a)(2)(B) requires the operator to "routinely monitor" the liner's integrity, but doesn't explain how that will be accomplished or define what routinely would be. As Commission Shift summarized in its comments on § 4.114, there are companies in Texas that are able to inspect the integrity of a liner in-situ, as well as several ASTM standards explaining how geomembrane integrity can be monitored. The Commission should confirm that those methods will be required and create a form and guidelines that operators use to keep track of pit liner integrity. If liner integrity is to be inspected by periodically emptying the pit and making visual inspections, operators should be required to photograph all actual and potential failure points and include that in the documentation required in (a)(2)(C). Commission Shift suggests that Commission set a frequency for these inspections to take place.[132] Commission Shift also urges the Commission to require similar monitoring of the liners in completion and workover pits (subsection (c)) and fresh makeup water pits and fresh mining water pits (subsection (d)); neither of these subsections not appear to include any liner monitoring requirement, even though the potential for pollution exists.

Commission Shift remains concerned that subsection f, regulating small sumps, is insufficient to protect neighboring surface owners and the environment from inadvertent spills from sumps. Commission Shift also requests clarification as to what is meant by a "small sump pit"—a term that appears only once in the rules:

> (f) Small sump.
>
> (1) Authorized pit contents. A person shall not deposit or cause to be deposited into ***a small sump pit*** any oil field fluids or oil and gas wastes other than the following:
>
> > (A) oil field fluids or oil and gas wastes collected in a pit and in a manner meeting the requirements of 40 Code of Federal Regulations (CFR) Part 279 or Part 280 or oil field fluids or oil and gas wastes collected in a pit that is excluded from the definition of underground storage tank under 40 CFR Part 280 because it is a pipeline facility regulated under the Natural Gas Pipeline Safety Act of 1968, the Hazardous Liquid Pipeline Safety Act of 1979, or comparable state law; or
> >
> > (B) oil field fluids or oil and gas wastes collected in a small sump as defined in this subchapter, provided the contents of the sump are removed for proper disposal at regular intervals to avoid overfilling the small sump.

The Commission should clarify what rules apply to "small sump pits" so that the public can provide meaningful comment on this section. Commission Shift also notes that the size of a sump is not necessarily the best proxy for how waste is processed through it (and thus the amount of risk it poses to human and environmental health). There is a difference between a "small" sump that is used to collect a couple of barrels of liquid a day versus a sump that is part of system that moves thousands of barrels per day. The Commission should regulate the latter more strictly.

Action leakage rates. Section 4.115(g) raises an issue that applies anywhere in the rules synthetic liners are discussed. This section discusses rules applicable only to non-commercial fluid recycling pits and proposes that it is acceptable for a pit built with a synthetic liner to leak 1,000 gallons per acre per day or more, if the calculated action leakage rate is larger.

[132] As drafted, section (g)(2)(B) implies that "routine" monitoring might be as little as annually. That is not frequent enough to protect human health and the environment, and the Commission should revise (g)(2)(B) to require more frequent inspections.

First, Commission Shift requests that the Commission clarify why only non-commercial fluid recycling pits have action leakage rates —and not any other type of authorized pit with a leak detection system.

Second, Commission Shift requests that the Commission explain why such a high leakage rate is allowed through a synthetic liner, which when properly installed should not leak. The Commission has not offered any justification for setting the allowable leakage rate so high. The leakage rate for any given pit will vary based on the pit's design and the amount of liquid in the pit, and very likely may be less than 1000 gallons/acre/day. At a minimum the rules should set the leakage rate to be the ***lower*** of the default rate or the calculated rate.

Third, even though the acceptable leakage rate is based on a daily value, the rule requires only monthly monitoring. A leaking pit that is in intermittent use may be able to pass a monthly test, even though it in fact leaks at an excessive rate any time the pit is full.[133] The Commission should require monitoring whenever the pit is in use,[134] and also specify the methods used for monitoring and how the "water passing through the primary liner" would be measured. Simply dividing by the number of days between measurements does not take into consideration the days that the pit is not in use—nor in the case of a leak on the inside berms, when the liquid level is below the portion of the liner that is damaged. The rules should reflect the purpose of an action leakage rate, which is to determine if the liner is damaged and to trigger plans for locating and repairing the damage before the pit is put back into use.

Taking all of the previous concerns into consideration, section 4.115(g)(2)(D) should thus be revised as follows:

> (D) If the operator does not propose to empty the non-commercial fluid recycling pit and inspect the pit liner on at least a monthly ~~an annual~~ basis, the operator shall install a double liner and leak detection system. A leak detection system shall be installed between a primary and secondary liner. The leak detection system shall be monitored ~~on a monthly basis~~ each day the pit is in use to determine if the primary liner has failed. The primary liner has failed if the volume of water passing through the primary liner exceeds the action leakage rate, as calculated using accepted procedures, or 1,000 gallons per acre per day, whichever is ~~larger~~ smaller.

[133] E.g., a pit that leaks 2,000 gallons/acre/day when full could pass a monthly monitoring inspection if it is empty more than half the month.

[134] It is not unreasonable to require more frequent monitoring than monthly. Non-commercial fluid recycling pits are often used at the well pad while the well is actively being worked on. Personnel are already onsite everyday conducting operations and frequent monitoring, like that required for permitted pits, is appropriate and will better protect human and environmental health.

4. DIVISION 4 REQUIREMENTS FOR ALL PERMITTED WASTE MANAGEMENT OPERATIONS

§4.121. Permit Term. Page 37

Commission Shift urges the Commission to make clear in its rulemaking that when permits that have been grandfathered in through subsection (b) come up for renewal or modification, the Commission shall review and update all permit conditions to ensure each facility is in full compliance with the new rules ***and*** that the public will be included in the process.

§4.122. Permit Renewals, Transfers, and Amendments. Page 37

Commission Shift is concerned that this section as drafted with not allow for robust and meaningful public participation in renewals, transfers, and amendments to permits. Flaws include the fact that according to the proposed § 4.122(b) (renewal applications) notice is in the same manner as the initial application; (c) is silent as to notice for transfer applications; and in (d) notice is not guaranteed during amendment applications—it is left to the Commission's discretion based "on materiality" of the amendment. This language is insufficient to safeguard the public and allow for meaningful participation: notice should automatically be required for all renewals, transfers, and amendments. Such language could be added to section a.[135]

If the Commission prefers to make such alterations in a piecemeal fashion, subsection b(3) (renewals), could be altered as follows to guarantee notice:

> § 4.122 (b)(3) ~~If the initial application for the permit type required notice, n~~Notice of the renewal shall be made in the same manner as ~~in~~ if it were an ~~the~~ initial application.

Without these changes, the proposal does not guarantee notice ***and*** limits the way notice is delivered to potentially more archaic methods that are not as successful in delivering notice. This language grandfathers in archaic notice requirements and restricts the Commission's ability to modernize the ways notice are given (e.g., adding electronic notification in addition to mailed or published notice). Notice should be delivered to the current surface owners in the manner most likely to be effective, not based on what was done in the past.

As for subsection (d)(2)(C) (amendments), Commission Shift suggests the following revisions:

> 4.122(d)(2)(C) ~~Depending on the materiality of the proposed permit amendments, t~~The applicant shall ~~Director may require~~ provide notice as described in § 4.125 and, if the permit is for a commercial facility, as described in § 4.141. ~~to surface owners, adjacent landowners, notice by publication, and/or notice to any persons the Director determines may be affected by the proposed amendment.~~

[135] For example, by appending the following sentence to § 4.122(a): "Notice shall be required for all renewals, transfers, and amendments in the same manner as if it were an initial application."

This edit is intended to ensure that notice is given for all amendment applications automatically, not just “depending on the materiality of the proposed permit amendment,” which is vague.[136] A bright-line requirement removes ambiguity for operators, the Commission, and the public and encourages transparency.

In addition, the Commission should make clear that it will require all renewals, transfers, and amendments comply with the rules in effect at the time a request is received. The Commission should consider rewriting this 4.122(a) to include this mandatory language as follows:

> (a) Compliance with rules in effect at the time of permit renewals, transfers, or amendments. To ensure compliance with the rules in effect at the time of a request to renew, transfer, or amend a permit, the Commission may review and revise permit conditions when it receives the request <u>so that all permit conditions shall comply with the rules in effect at the time the permit renewal, transfer, or amendment is granted</u>.

Finally, Commission Shift agrees that both a facility and a records inspection is essential before an amendment is approved under (d)(5) (“The permit shall not be renewed unless the facility is compliant with Commission rules and permit conditions, as verified by a facility and records inspection.”) The results of that inspection should be published to the Commission’s electronic public-facing database as well.

As for transfers (4.122(c)), Commission Shift urges the Commission to establish strong rules that would prevent transfers between substantially similar entities in order to obscure a history of rule violations. The rules should have a compliance history element that would prevent bad actors from cleaning their record with new company names and histories; transfer applications should require that the applicant identify all former and related entities owned by the same operator or group of individuals and should take an applicant’s compliance history into account. The Commission should prevent an owner of a non-compliant facility purchasing that facility using a new ‘clean’ LLC by requiring applicants to identify all related entities in an application.[137]

In addition, the Commission should explore limiting transfers until only after a facility has been constructed according to the permitted specifications.[138] It is the original applicant, not a transferee, who certifies that an application is “true, correct, and complete to the best of my knowledge,” 4.124(c), and not all operators have the same compliance history and experience operating facilities. Especially if the only opportunity for public involvement is at the application stage, the public should be able to rely on the assumption that the original applicant will be the one constructing the facility. The Commission has allowed transfers prior to construction in the past, including the Hohn Facility in

[136] Especially considering that the Commission has not given any examples of what might be “material” or not, or what might constitute a major or minor amendment.
[137] The Commission could add this as a requirement in § 4.124(d)(7) (information required to be provided about applicant).
[138] This prohibition should extend to commercial recycling facilities as well. Compare with 4.218.

DeWitt County, a facility that has caused reoccurring pollution concerns for neighbors.[139] Commission Shift thus respectfully requests that the Commission confirm that the rules prohibit transfer before construction, as 4.122(d)(6) implies:

> 4.122(d)(6) The permit shall not be transferred unless the facility is compliant with Commission rules and permit conditions, as verified by a facility and records inspection.

§4.123. Permit Modification, Suspension and Termination. Page 39

Commission Shift suggests that the Commission expressly acknowledge as part of this rulemaking that citizen-collected evidence can support a finding of good cause to modify, suspend, or terminate a permit. Adding this acknowledgement would encourage communities that the Commission respects and values the public's contribution to protecting human health and the environment.

§4.124. Requirements Applicable to All Permit Applications and Reports. Page 40

Commission Shift strongly urges the Commission to require that all permit applications include a plan for community relations and public information for the facility.[140] The plan should provide a point of contact for the community, a list of all operations at the facility (both permitted and unpermitted), the facility's plan for severe weather events and stormwater, the contact information for other regulatory agencies with jurisdiction over the facility, and an explanation of how concerns can be raised with the operator and with regulatory agencies. The facility should make copies of the plan available in both Spanish and English, and any other language appropriate based on the population living near the facility.

Commission Shift also suggests that each application should include a proposed inspection checklist that would include site-specific features, providing direction for an inspector to confirm that the actual operations conform to the authorized and permitted operations. The current inspection forms used at many facilities are generic and do not describe the permitted operations. The inspection form should make it easy for inspectors to confirm things like freeboard, setbacks, maximum waste height, etc. It should also indicate where photographs should be taken from (and of what), so that a consistent record is made across inspections.

Commission Shift also suggests that each application include a review and discussion of the application and permitting files for all previous oil and gas waste permit applications filed within a 30-

[139] Ex. 35 Garcia, Karina. Waste spills at a disposal site near Nordheim. (May 17, 2023) https://www.crossroadstoday.com/news/waste-spills-at-a-disposal-site-near-nordheim/article_e941bce0-f390-11ed-a3ec-df18b668a357.html Ex. 36, 2017 STF-062 Pyote to Petro_Transfer.

[140] This dovetails with recommendations in the (Ex. 11) 2022 STRONGER Guidelines ("A community relations or public information plan should be considered.") at 53.

mile radius in the last ten years.[141] These applications and permits should contain information about the site suitability, and would aid communities, the applicant, and the Commission in determining whether the facility should be permitted.

These three suggestions could be added to § 4.124 with the following language:[142]

<u>(f) The permit application shall contain the following documents:</u>

<u>(1) A proposed community relations and public information plan;</u>

<u>(2) A proposed inspection form that is site-specific, which contains sufficient information for operators and inspectors to document compliance with the site-specific requirements set for all authorized and permitted operations; and</u>

<u>(3) A review and analysis of all previous oil and gas waste permit applications and permits (both filed and issued) within a 30-mile radius of the property boundary in the last ten years, including a review and analysis of the data contained therein regarding the suitability of the site for the proposed operations.</u>

Commission Shift strongly supports the Commission's requirement that any lab analyses done in as part of Subchapters A and B must be as described in §4.124(d)(3) and conducted by an independent, accredited laboratory and meet federal sampling standards. It is also essential that the full lab reports and chains of custody be submitted to the Commission and made publicly available so that the data can be reviewed and understood within the context of sampling methods and their limitations. The sample collection itself should also be conducted by independent samplers neither owned nor operated by the permittee. This requirement should be added as a third requirement under (d)(3).

Commission Shift is concerned that several terms in (e)(4) are vague and could be left open to interpretation. The Commission should consider adding more specificity to what "relevant calibration records" for NORM screening equipment includes. In addition, it is not clear to Commission Shift what would suffice for a survey that is conducted "in a systematic grid pattern." The Commission should consider defining the maximum spacing of this grid that would be acceptable.

§4.125. Notice Applicable to All Permitted Activities. Page 41

Commission Shift strenuously urges the Commission to take this rulemaking opportunity to increase the notice given for all permitted activities, both commercial and non-commercial.[143] These comments thus apply to the language in § 4.125, § 4.133, and in § 4.141.

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[141] Thirty miles was the radius proposed for a statement of need and 10 years is the length of time an applicant must consider when reviewing flooding hazards.

[142] This language might also be incorporated in § 4.128(a), which describes the information that shall be submitted with each permit application.

[143] Especially since the distinction between commercial and non-commercial is not based on the size or type of facility, the volume of waste processed, nor its risks to human and environmental health.

Direct notice (subsection a) should not be limited to the surface owner of the property, as it is in § 4.125(a)(1)(A). Permitted oil and gas operations have the potential to impact nearby residents and landowners living further away, and contaminate subsurface waters off site. Direct notice for all permitted activities should be sent to all surface owners within a mile of the proposed facility's property boundary. This prompts meaningful public participation ***and*** will help identify risks to human and environmental health. It is well known that it is difficult to identify water wells within a one-mile radius of the facility from a records review[144]—one of the best ways to identify wells is by actually talking to the residents living within one mile of the facility. Notice should also be sent any groundwater district within one mile of the proposed facility.

Notice should be sent in English and Spanish, and any other language that the Commission determines is appropriate given the languages spoken in the area.[145] This is imperative in order to adequately identify and engage with the frontline and environmental justice communities that may be living near the proposed operations. To meet these goals, section 4.125(a) could be amended as follows:

> (1) The applicant shall give notice of the permit application by registered or certified mail to the following persons on or before the date the application is filed with the Commission:
>
> > (A) the surface owners of the tract upon which the facility will be located
> >
> > (B) all surface owners within one mile of the facility's property boundary;
> >
> > (C) the appropriate official(s) for all groundwater conservation districts within one mile of the facility's property boundary;
> >
> > (D) the city clerk or other appropriate official if the tract upon which the facility will be located lies within the corporate limits of an incorporated city, town, or village; and
> >
> > (E) any other class of persons, such as offset operators, adjacent surface owners, or an appropriate authority, that the Director determines should receive notice of an application.
>
> . . .
>
> (3) The notice of the permit application, the complete copy of the application, including all attachments, and the letter required by § 4.125(a)(2) shall be translated into Spanish and any other language that the Director deems appropriate based on the languages spoken in the area. These translated materials shall be included as part of the direct notice.

Published notice (subsection b) should be required for all facilities as well, regardless of whether a facility is commercial or not. Notice should be published both in print and electronically. Printed notice should not be limited to the county where the facility is built (as b(1) proposes), because

[144] § 4.126(d)(6) rightfully requires applicants to identify all water wells within one mile of the facility boundary.

[145] Commission Shift suggests that notice should be published in the major languages spoken in all counties within one mile of the proposed facility, taking into consideration the populations with limited English proficiency.

facilities may be proposed on the border of two counties. Instead, notices should be required to be printed a publication that has a circulation in every county that is within a mile of the facility. Section 4.125(b)(1) should thus be amended as follows:

Electronic notice should also be required. Both TCEQ and Louisiana's Department of Environmental Quality already do this. TCEQ maintains a public notice website in which anyone can search for notices and which is updated daily.[146] TCEQ also maintains permanent mailing lists based on applicant or county that anyone may request to join.[147] Those who sign up by county are sent all air, water, and waste notices for that county.

Louisiana's Department of Environmental Quality's also does better than the Commission when it comes to public notice. LDEQ posts public notice information to their websites and offer listservs that anyone may join to receive permit public notices by email or by hardcopy.[148] A screenshot of LDEQ's website (https://www.deq.louisiana.gov/public-notices) is shown below:

[146] Search for TCEQ Public Notices. https://www.tceq.texas.gov/agency/decisions/cc/pub_notice.html (a search run October 31, 2023 returned multiple notices that were dated October 31, 2023).

[147] From the TCEQ at https://www.tceq.texas.gov/agency/decisions/participation/permitting-participation/public-participation-9-1-2015:

Getting Placed on a Mailing List

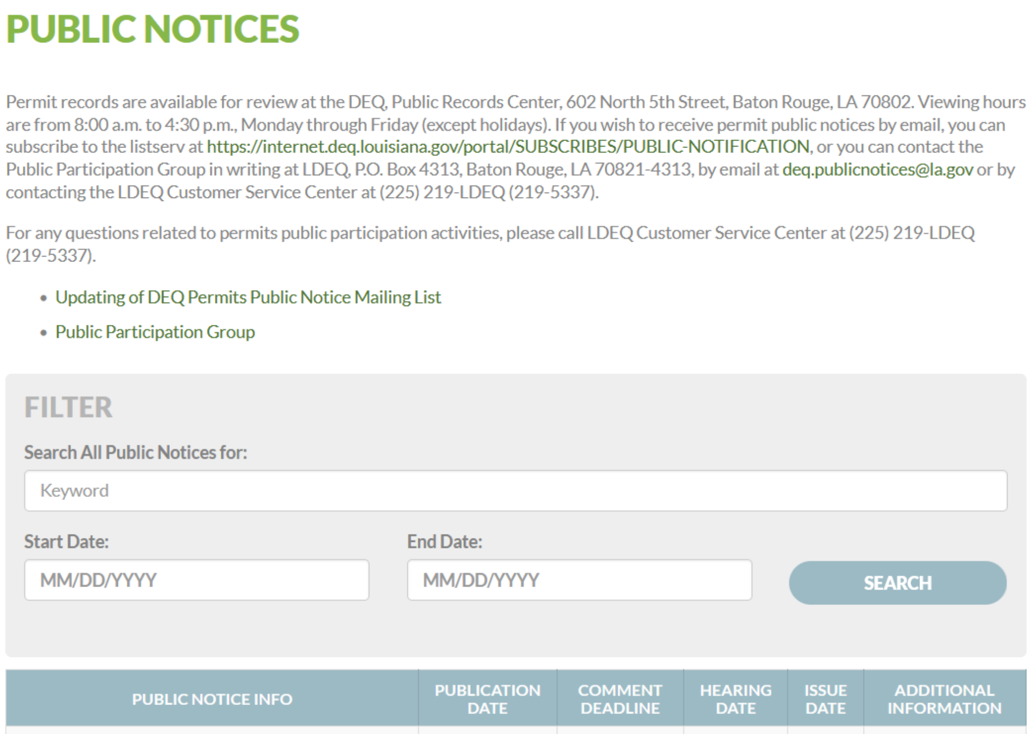
If you submit a comment, request a public meeting, or request a contested case hearing regarding a specific permit application, the TCEQ will automatically add you to the mailing list for that application. Y**ou may also request to be on either of these two kinds of mailing lists:**

The permanent mailing list for a specific applicant name and permit number.

The permanent mailing list for a specific county (which includes all air, water, and waste notices in that county).

To get on either of these additional mailing lists, you must send a request to the chief clerk. In your request, specify the mailing list or lists you want to be on, and include your name and address.

[148] Ex. 37 LDEQ. Updating of DEQ Permits Public Notice Mailing List. (describing how both a hardcopy and an electronic mailout list is offered) (Accessed October 31, 2023). https://www.deq.louisiana.gov/assets/docs/Public_Notices/UpdatingDEQPermitsPublicNoticeMailingList.pdf



PUBLIC NOTICES

Permit records are available for review at the DEQ, Public Records Center, 602 North 5th Street, Baton Rouge, LA 70802. Viewing hours are from 8:00 a.m. to 4:30 p.m., Monday through Friday (except holidays). If you wish to receive permit public notices by email, you can subscribe to the listserv at https://internet.deq.louisiana.gov/portal/SUBSCRIBES/PUBLIC-NOTIFICATION, or you can contact the Public Participation Group in writing at LDEQ, P.O. Box 4313, Baton Rouge, LA 70821-4313, by email at deq.publicnotices@la.gov or by contacting the LDEQ Customer Service Center at (225) 219-LDEQ (219-5337).

For any questions related to permits public participation activities, please call LDEQ Customer Service Center at (225) 219-LDEQ (219-5337).

- Updating of DEQ Permits Public Notice Mailing List
- Public Participation Group

FILTER

Search All Public Notices for:

Keyword

Start Date: MM/DD/YYYY

End Date: MM/DD/YYYY

SEARCH

PUBLIC NOTICE INFO	PUBLICATION DATE	COMMENT DEADLINE	HEARING DATE	ISSUE DATE	ADDITIONAL INFORMATION

The Commission should require that all applicants prepare public notice materials and post them online. Like Louisiana and the TCEQ, the Commission should maintain a list of every person who has signed up to receive notices of any oil and gas application filed in Texas and ensure that all who have requested notice receive it.

Deadline for protests. Commission Shift is also strenuously objects to the narrow window provided for protests. Having a long enough protest period is important because typically only those who register a protest within this window can provide feedback on whether the application is sufficiently protective of human health in the environment. Commission Shift would support the creation of a more participatory permitting process, for example, one that would:

- require applicants to provide direct and published "notice of intent" to apply for a permit at least 30 days before applying
- set all applications for a hearing once the application is complete, regardless if a protest is received[149]
- give at least 30 days direct and published notice of the hearing (which is same time frame applicants have to respond to protests)[150]
- prohibit modifications or supplements to the application once it is set for hearing (i.e., not allowing applicants to endlessly amend applications and create costly moving targets for the public & Commission to review)[151] After all, "it is prejudicial to a protesting party when the administratively complete permit and its volumes of supporting Application documents

[149] I.e., remove the need to protest in 15 days, which is found at least in sections 4.125(a),(b), 4.133, 4.134(g),(h), 4.135(a),(b))
[150] Which would affect at least sections 4.125(a) and (b).
[151] This would affect at least sections 4.134, 4.135.

referred to the Hearings Division, is not the permit or Application that is presented in a hearing"[152]
- at the hearing, allow all interested persons the opportunity to present testimony, facts, or evidence related to the application or to ask questions

Both Louisiana and the TCEQ implement more inclusive processes like the one described above. However, if the Commission rejects this proposal, at a minimum potential protestants should be given the longer of either 30 calendar days from the date of application or 30 calendar days from the date of last publication in which to file a protest.[153] This would come closer to aligning with the notice periods provided in almost all TCEQ applications[154] and match the 30-days of notice that applicants currently have to respond to protests of their waste permit applications.

§4.126. Location and Real Property Information. Page 44

Commission Shift is concerned that the map features identified in (d) will not be used in the decision of whether a facility is appropriate for the location. For example, as the rule is drafted now, the applicant is directed to collect information about nearby schools, churches, and hospitals, but not required to use this in any way and not required to provide notice to them. Facilities should be prohibited next to sensitive receptors like these (for more on setbacks, see Commission Shift's comments on § 4.150). Likewise, the applicant is asked to identify all water wells within one mile—and all residences and commercial buildings within the same radius if the facility is for disposal—but is not required to send them notice of the application. Commission Shift's proposed changes to who gets notice attempts to address this disconnect (see comments on § 4.125).

§4.127. Engineering and Geologic Information. Page 46

Commission Shift urges the Commission to require site investigations for all operations seeking to be permitted. As discussed in its comments in Division 3 (§ 4.114(h) related to groundwater

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[152] This quote comes from the opinion of one of the hearing examiners tasked with reviewing a waste permit application proposed for San Augustine County, acknowledging how burdensome it is to the Commission and protestant when the facility's scope at the hearing was "ever-evolving." (OG-20-00004639) (PA Prospect in San Augustine County) at *44.

[153] In other words, § 4.125(a)(2)(F) would be amended to state "(F) a statement that any protest to the application must be filed with the Commission within ~~15~~ 30 calendar days of the date the application is filed with the Commission or within ~~15~~ 30 calendar days of the last date of publication, whichever is later. § 4.125(b)(2)(F) would need to be amended to state "(F) state that affected persons may protest the application by filing a protest with the Commission within ~~15~~ 30 calendar days of the last date of publication or within 30 calendar days of the date the application is filed with the Commission, whichever is later;"

[154] This is actually an additional notice period once the agency has completed its preliminary review, during which time any member of the public may submit additional comments. TCEQ. Overview: Public Participation in Environmental Permitting--for Applications Filed on or after Sept. 1, 2015 https://www.tceq.texas.gov/agency/decisions/participation/permitting-participation/public-participation-9-1-2015 ("Except for certain air applications, the public comment period ends no earlier than 30 days from the last publication date of the NAPD [Notice of Application and Preliminary Decision]. If a public meeting is held after the close of the comment period, the comment period extends to the end of the public meeting.")

monitoring), the location of subsurface water can only be determined through soil borings and companion soil boring logs that capture continuous soil samples and log continuous descriptions by depth. As such Commission Shift encourages the Commission to amend section 4.127(b) as follows:

> (b) ~~If information is not available to address subsection (a) of this section,~~ a site investigation including soil boring, sampling, and analysis is required.

Commission Shift also urges the Commission to require both documents and photographs documenting the as-built condition of the entire facility, not just the permitted waste management units. Photographs are necessary to confirm that the facility has been built to comply with all requirements, including setbacks. As such, Commission Shift suggests §4.127(d) be modified to state:

> Prior to commencement of operations at a commercial facility, the permittee shall provide the Director with drawings <u>and photographs</u> documenting the as-built condition of ~~the permitted waste management units at the facility~~ <u>the facility, including all equipment and waste management units. Photographs shall include at least one aerial photograph. All photographs shall include sufficient detail to confirm that the facility has been built in compliance with all permitted conditions.</u>

§4.128. Design and Construction. Page 46

In it comments on § 4.124, Commission Shift suggested three additional items that should be included in each permit application. The need for each of those items could also be appended to § 4.128(a) as items 7-9 as follows:

> (a) Application. The following information shall be submitted with each permit application: . . .
>
> > <u>(7) A proposed community relations and public information plan;</u>
> >
> > <u>(8) A proposed inspection form that is site-specific, which contains sufficient information for operators and inspectors to document compliance with the site-specific requirements set for all authorized and permitted operations; and</u>
> >
> > <u>(9) A review and analysis of all previous oil and gas waste permit applications and permits (both filed and issued) within a 30-mile radius of the property boundary in the last ten years, including a review and analysis of the data contained therein regarding the suitability of the site for the proposed operations.</u>

Commission Shift requests that the Commission clarify subsection (b)(3)'s statement on acceptable firewalls. If a firewall surrounds more than one tank, it should be able to withstand the maximum capacity of **all** tanks (not just the largest tank) within the firewall, plus freeboard to withstand a 25-year, 24-hour rainfall event. Subsection (b)(3) should be revised accordingly. Likewise, Commission Shift reiterates its concern that § 4.128(b)(4) requires stormwater to be collected "within 24 hours of accessibility," which may not be possible for several days during severe weather events. It is therefore imperative that the Commission require sufficient freeboard on all waste management units.

§4.129. Operation. Page 48

Commission Shift urges the Commission to require immediate action on spills, as it does in Division 10. Commission Shift urges the Commission to incorporate the language used in Division 10 as follows:[155]

> (b)(4) The permitee shall take immediate corrective action in the event of any spill of waste, chemical, or any other material. The permittee shall take any measures necessary to stop or control the release and spills shall be collected and containerized within 24 hours and processed through the treatment system or disposed of in an authorized manner. The release shall be reported to the District Office within 24 hours of discovery of the release.

§4.130. Reporting. Page 49

In its comments on § 4.108, Commission Shift discussed the need for all records, including those required by § 4.130, to be made publicly available, not just made “available for review and/or copying upon request,” as subsection (c) is currently drafted. Making these documents publicly available lets the public help monitor the compliance at these facilities and inspires confidence that good-actor facilities are being responsibly run.

§4.131. Monitoring. Page 50

Commission Shift strongly urges the Commission to require groundwater investigations and monitoring at every site. Subsection (b) must be revised.[156] Commission Shift suggests that better language would be moving the language from (b)(2)(D) up into (b)(1) as follows:

> (1) If shallow groundwater is present within 100 feet below ground surface at the site, a minimum of three groundwater monitoring wells shall be installed ~~may be required for some facilities, including but not limited to: brine pits, disposal pits, reclamation plants, commercial waste separation facilities, commercial recycling facilities, and commercial landfarming facilities~~. Factors that the Commission will consider in assessing whether groundwater monitoring is required at depths beyond 100 feet include:
>
> (A) the volume and characteristics of the oil and gas waste to be managed at the facility;
>
> (B) depth to and quality of groundwater ~~within~~ beyond 100 feet below ground surface; ~~and~~
>
> (C) presence or absence of natural clay layers in subsurface soils; and
>
> (D) any other factor the Director deems relevant to preventing pollution.

[155] Compare with § 4.196(b)(7) “Immediate corrective action shall be taken in all cases where pollution has occurred. An operator responsible for the pollution shall remove immediately such oil, oil field waste, or other pollution materials from the waters and the shoreline where it is found. Such removal operations will be at the expense of the responsible operator.” The Commission should also reiterate that all other responsibilities in (b)(7) apply to operators of permitted operations.

[156] Even as drafted, it is confusing—it only states that wells ***may*** be required at certain facilities, which is a truism for all other facilities not listed—so why list any facilities by name at all? It also appears to conflict with 4.131(b)(2)(D), which would require groundwater monitoring whenever groundwater is present within 100 feet below ground surface

Commission Shift reiterates that it is all subsurface waters that the Commission is under a duty to protect—not just strata containing sufficient water for drinking or agriculture. Low-bearing formations may take additional time—more than 24 hours—to develop sufficient water that can be sampled and before a driller can confirm whether subsurface water is present.

Commission Shift urges the Commission to also prohibit operators from installing a monitoring well at the same exact location where it has taken soil borings during the geological investigation phase. Soil borings used to investigate the presence or absence of subsurface water are typically conducted before the site's groundwater gradient has been fully understood. The monitoring well locations should be established only after the soil boring data has been fully analyzed and reviewed by a certified professional. Soil borings should be fully plugged and abandoned to prevent pollution.

Commission Shift also urges the Commission to have operators pause operations for as long as a monitoring well is not operational. Commission Shift is aware of at least one operator that was allowed to continue operations without a full suite of operational wells, even though reports of contamination had been made about the facility. Section 4.131(b)(2)(B) should be revised as follows:

> (b)(2)(B) The monitor wells shall be able to provide representative samples of groundwater underlying the site for the duration of facility operations. If a monitor well is not capable of providing a representative sample, the operator shall notify the Technical Permitting Section <u>within 24 hours and cease operations at the facility immediately until the monitoring well has been replaced.</u>

As for (b)(2)(D), the Commission appears to have omitted a requirement for upgradient wells to be installed. Upgradient wells are necessary to obtain groundwater samples that are representative of regional conditions and are not affected by the permitted site. Commission Shift thus suggests the following revision:

> (b)(2)(D) If shallow groundwater is present within 100 feet below ground surface at the site, a minimum of three groundwater monitoring wells shall be installed. Wells shall be spaced around the facility or pit, close to the facility operational area, with at least two wells on the estimated down-gradient side of the operational area<u>, and at least one well on the estimated up-gradient side of the operational area</u>. Additional wells may be required for larger facilities.

As for (b)(2)(L)(ii), the Commission should clarify that a professional, licensed land surveyor[157] should be the one to survey the well head elevations. An accurate survey is essential for determining groundwater gradients and identifying if these gradients have shifted over time, as is possible especially over the long lifetime expected for some of these facilities. Commission Shift suggests the following language to achieve this goal:

> (b)(2)(L)(ii) a survey elevation for each well head reference point (top of casing) relative to a real or arbitrary on-site benchmark and relative to mean sea level. <u>Surveys shall be conducted by a licensed land surveyor.</u>

[157] Licensed State Land Surveyor (LSLS) at https://pels.texas.gov/lsls.htm

As for subsection(b)(4)(C), Commission Shift believe that the Commission has inadvertently omitted BTEX from the list of parameters sampled. This subsection should therefore be modified as follows:

> (C) The following measurements and analyses shall be reported to Technical Permitting Section after any sampling event no later than 15 days after the permittee receives the laboratory analysis results: static water level, pH, and concentrations of benzene, <u>toluene, ethylbenzene, xylene,</u> total petroleum hydrocarbons, total dissolved solids, soluble cations (calcium, magnesium, potassium, and sodium), and soluble anions (bromides, carbonates, chlorides, nitrates, and sulfates).

Finally, Commission Shift believes that human and environmental health is best protected if operations cease when potential pollution or potential liner failure is indicated. Commission Shift recommends that (b)(4)(D) be amended as follows:

> If any of the parameters identified in subparagraph (C) of this paragraph indicate potential pollution, or the potential failure of the liner system, the Commission may require additional monitoring events and/or may require analysis of additional parameters. <u>In the meantime, the operator shall be prohibited from accepting additional waste at the facility until the facility no longer is a source of potential pollution</u>.

§4.132. Closure. Page 53

Commission Shift understands that these closure requirements apply to all permitted operations, including disposal pits, waste separation, landfarming and reclamation plants. As drafted, the rules state that operators must submit detailed closure plans at two separate times: first as part of the application process (4.132(a)) and second at least 30 days before commencing closure activities 4.132(b)(2). Operators should not be allowed to weaken their closure plans after the permit has been granted (i.e., after the only opportunity for public involvement has concluded). The final closure plan approved must be equal to or more protective of human health and the environment than the one approved during the application process. Any deviations from the plan should be treated as a request to amend the permit and trigger a requirement for public notice and comment. As such, Commission Shift suggests that the following addition to 4.132(b)(2) could address this problem:

> (2) The permittee shall submit a detailed closure plan to the Technical Permitting Section at least 30 days prior to commencement of any closure activity. The Technical Permitting Section must approve the detailed closure plan before the permittee may initiate closure operations. <u>If the detailed closure plan differs from the permitted closure plan, the permittee must seek a permit amendment per § 4.122(d) and the Director shall require notice be given per § 4.122(d)(C). The Technical Permitting Section shall not approve a closure plan that is less protective of human health and the environment than the plan approved during the application process.</u>

Section 4.132(b)(3) should also be amended to state that if the soil samples taken during closure exceed the authorized limits or if the Commission determines additional remediation is required, the Commission “shall require” (not “may require”) additional closure operations:

> (3) Once the permittee has removed all waste, equipment, concrete pads, contaminated soil, and any other material in accordance with the closure plan, the permittee shall conduct soil sampling in accordance with the approved soil sampling plan. Soil samples shall be analyzed for the parameters in the permit and/or soil sampling plan and submitted to the Technical Permitting Section no later than 30 days after the permittee receives the laboratory results. The Technical Permitting Section ~~may~~ shall require the permittee to conduct additional closure operations if the soil sample results exceed the authorized limits and/or the Technical Permitting Section determines that additional remediation is required to prevent pollution caused or contributed to by operations at the facility.

§4.133. Protests. Page 54

Commission Shift reiterates its deep concern that the time frame allotted for protests does not allow for meaningful participation by frontline groups and environmental justice communities (see Commission Shifts previous comments on § 4.125). At a bare minimum, a 30-day protest period must be allotted. Furthermore, participation in the hearing process should be open to any interested person who may have relevant information about the application.

Section 4.133(a) would then be rewritten as:

> (a) The Technical Permitting Section shall notify the applicant if ~~an affected~~ any person files a written protest with the Commission within ~~15~~ 30 calendar days of the date the application is date-stamped at the Commission or the date notice was last published, whichever is later.

§4.134. Application Review and Administrative Decision. Page 55

Commission Shift remains unconvinced that sections 4.134 and 4.135 will solve the deep flaws inherent in the Commission's system for processing permits. There appears to still be no means for Technical Permitting Section staff to deny technically flawed permits outright—no matter what an applicant has provided in its application, it appears that the applicant would be able to request a hearing on that application, even if it is declared administratively incomplete and denied. This is a profound waste of the resources of the Commission and frontline communities who then must spend time and money in a hearing defending against a facility or pit that continues to fail at providing adequate information to support the drafting of a facility permit and its subsequent approval. Moreover, it appears that this rulemaking does nothing to change the fact that Commissioners may overrule both technical permitting staff and hearing examiner's final orders when they determine that an application should be denied.

Commission Shift would welcome the opportunity to collaborate with the Commission on creating a more equitable system for processing permits.[158] Until then, Commission Shift urges the

[158] Both TCEQ and LDEQ have procedures that appear more sensible, which include issuing multiple notices, providing for 30-day or more comment periods, and allow participation from all interested persons.

Commission to at a minimum amend section (f) to state that applications that fail to meet the Commission's minimum standards shall be denied:

> (f) The Technical Permitting Section ~~may~~ shall administratively deny the application if it does not meet the requirements of this subchapter or other laws, rules, or orders of the Commission. The Technical Permitting Section shall provide the applicant written notice of the basis for administrative denial.

§4.135. Hearings. Page 56

Again, Commission Shift does not see how sections 4.134 and 4.135 will meaningfully improve the currently broken system of permitting oil and gas waste operations. Commission Shift is of the opinion that applicants should not be allowed to request hearings on applications that have been administratively denied, and suggests the following language be added as a subsection (c):

> (c) The applicant may not request a hearing if the application has been administratively denied.

5. DIVISION 5 ADDITIONAL REQUIREMENTS FOR COMMERCIAL FACILITIES

§4.140. Additional Requirements for Commercial Facilities. Page 56

Omitted from this draft is a proposal that was in a previous draft—that operators should show a need for a commercial facility before being eligible for a permit. Too many communities have had to expend their own capital to challenge facilities proposed in close proximity without a statement of need.[159] Requiring a "statement of need" / "market analysis" has support from community members and operators alike, and should be added back in to § 4.140. [160] Commission Shift also joins other commentors in arguing that also needed is a ***forward***-looking market analysis, i.e., to consider permit applications that are going to be drilled in the future. It is the wells that have not yet been drilled that will generate the most waste needing disposal. Commission Shift thus requests that § 4.140 be amended to include the following:

> An application for a commercial waste facility shall include a statement of need, detailing the necessity for an additional commercial facility in the geographical market where the property and proposed facility are located. The statement of need shall include a map showing, within a 30-mile radius around the proposed facility:
>
> (1) All permitted commercial waste facilities;
>
> (2) All oil and/or gas wells drilled within the 12-month period prior to the date of the permit application submission; and
>
> (3) All oil and/or gas wells that have applied for a permit to be drilled within 12-month period after the permit application submission.

§4.141. Notice. Page 60

Commission Shift strongly urges the Commission to expand the notice given to frontline communities for all applications, including commercial applications. Insufficient notice is a common and frustrating complaint echoed by communities and landowners across the state. Meaningful

[159] Ex. 38 Sneath, Sara. Residents learn risks of possible facilities. Victoria Advocate. (March 14, 2014) https://www.victoriaadvocate.com/counties/dewitt/residents-learn-risks-of-possible-facilities/article_12bdb914-5536-58bd-89a7-dec61f6ae6f8.html (Facilities approximately 31 miles apart).

[160] As one disposal facility operator explains in favor of a statement of need:

> Commercial disposal facilities must be operated by companies with regulatory, operational and safety expertise. The consequences of (i) mismanagement of commercial facilities and/or (ii) the financial instability of some commercial facility operators, negatively impacts the Railroad Commission, landowners and Texas taxpayers. . . .
>
> Operators known for cutting operational and safety corners to maintain profitability must be discouraged from opening new facilities. A market analysis and an associated statement from the Commercial Facility applicant, detailing the necessity for an additional facility in the market where the proposed facility is to be located, should be a part of the Commission's assessment criteria for new commercial facility permits. The commercial facility operator seeking a new facility permit must provide a (i) statement outlining their operational experience/background and (ii) a "Statement of Need" providing supportive information related to historical drilling activity in the defined area and other disposal options in the market) for a new facility in the market area for the Commission's consideration.

Ex. 26 (Milestone comments) at 5.

participation is impossible on a short timescale, and many are disenfranchised from participating because they simply are never sent direct notice.

Commission Shift recognizes that the Commission has expanded the timeframe for notice & protest for commercial facilities from 15 days to as little as 22 days from the date of application[161] but this is ***still*** less than the 30 days applicants have to respond to protests (see § 4.133(b))—which by virtue of having filed the application they will already be on the lookout to expect—and will already have money, engineers, experts and lawyers lined up to respond and will already be familiar with the many new pages of 16 TAC Chapter 4 Subchapter A. In contrast, landowners, groundwater conservation districts and cities will have been caught unawares by a notice and yet will be forced to scramble with less time to secure the same resources, advise and knowledge—not to mention the time it takes to obtain copies of files from the Commission. As explained in Commission Shift's comments on section 4.125, all potential protestants should have at a minimum of 30 calendar days either from the date of published application or the last date of publication (whichever is longer).

The list of people and entities who receive direct notice must expand as well. Adverse impacts from permitted facilities are felt at a greater distance than 500 feet from the facility's fenceline—i.e., there are affected persons who are not being given notice of applications, which disenfranchises them. Groundwater conservation districts should also be given direct notice of all applications. Commission Shift refers the Commission its comments on § 4.125 above as to who should receive notice for all applications.

Also, as Commission Shift's comments in § 4.125 state, all published notice should also be posted electronically to the Commission's website with that notice automatically and electronically sent to a list of any interested person, who may sign up with the Commission to receive notices of any application filed in Texas. This is already standard practice at TCEQ and LDEQ and will better facilitate meaningful participation, which is a key to ensuring the public interest is protected.

§4.142. Operating Requirements Applicable to Commercial Facilities. Page 60

In its comments on Division 4, § 4.124, Commission Shift urged the Commission to require all applicants to include a community relations / public information plan and site-specific inspection forms as part of its permit application. The Commission should include these requirements in this section as well, adding to subsections to § 4.142 as follows:

> <u>(d) The operator shall develop and maintain a community relations and public information plan. The plan shall be maintained on-site and made available to the</u>

[161] The draft does not make it easy to calculate the notice period, since it is now based on the latter of two options (see 4.125(b)), which includes 15 days after the last date of published notice, which could be as quickly as 22 days after the application is filed. Under (b)(1) it is possible that the notice period could extend longer (if publication was delayed), but it is not guaranteed. The lack of a guaranteed 30-day notice period is problematic—thirty days should be the floor for all permitted activities.

> Commission upon request. A copy of the plan shall be posted publicly to the operator's website.
>
> (e) The operator shall develop and maintain a site-specific inspection form for all authorized and permitted operations at the facility. The inspection form shall be used for inspections. The form shall be maintained on-site and made available to the Commission upon request.

§4.143 Design and Construction. Page 60

Commission Shift urges the Commission to require both documents and photographs that clearly identify and describe the as-built condition of the facility (including all authorized and permitted operations). Photographs are necessary to confirm that the facility has been built to comply with all requirements, including setbacks. As such, Commission Shift suggests §4.143 be modified to state:

> Prior to commencement of operations at a commercial facility, the permittee shall provide the Director with drawings and photographs documenting the as-built condition of the facility, including all equipment and waste management units. Photographs shall include at least one aerial photograph. All photographs shall include sufficient detail to confirm that the facility has been built in compliance with all permitted conditions.

6. DIVISION 6 ADDITIONAL REQUIREMENTS FOR PERMITTED PITS

§4.150. Additional Requirements Applicable to Pits Authorized by Permit, Page 61

Commission Shift strongly urges the Commission to adopt more protective setbacks for all of the activities covered by Subchapter A (both "authorized" and permitted), with no exceptions allowed. As described in Part I, there are many communities and affected individuals who live further away from a pit than the distances described in (g) who have suffered and are continuing to suffer ill effects from these facilities.

Commission Shift is also concerned that no setbacks are required from sensitive residential, commercial, and other buildings, contrary to recommended practice and what's become typical in Louisiana. For example, the 2022 STRONGER Guidelines urge: [162]

> Where necessary to protect human health, E&P waste management facilities should not be located in close proximity to existing residences, schools, hospitals or commercial buildings. The need for minimum distance criteria from residences or other buildings to the boundary of E&P waste management facilities should be considered.

Louisiana has been protecting its communities and water better, prohibiting commercial facilities and transfer stations "within 1/4 mile [1320 ft] of a public water supply water well or within 1,000 feet of a private water supply well," and setting default setbacks from buildings, schools, and churches up to 2000 feet.[163] Louisiana's setbacks also vary based on the toxicity of the waste being handled.

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[162] Ex. 11 2022 STRONGER Guidelines at 36. https://www.strongerinc.org/wp-content/uploads/2022/07/2022-Edition-STRONGER-Guidelines.pdf

[163] LAC § 507. https://casetext.com/regulation/louisiana-administrative-code/title-43-natural-resources/part-xix-office-of-conservation-general-operations/subpart-1-statewide-order-no-29-b/chapter-5-off-site-storage-treatment-andor-

The Commission has even proposed stronger setbacks for certain commercial recycling facilities—facilities that unlike commercial disposal landfills, by rule do not exist for more than 2 years.[164]

Even these setbacks would place frontline communities too close to facilities for safety, as the communities in Nordheim, Orange Grove, and Waskom can confirm.[165] The cone of depression (or area of drawdown) for a public supply well can extend quite far, depending on the aquifer. It is also inappropriate to allow applicants to seek exceptions to setbacks, especially without public input (see comments on § 4.109). The Commission should also take into consideration the presence of environmental justice communities when considering whether a site is appropriate (e.g., by incorporating a review of EJScreen's data[166] or other comparable methods). In addition, Commission Shift supports measuring setbacks from the facility's property boundary, not from the pit or facility's fenceline. Waste does not necessarily stay in a pit—it can be tracked through a site and/or be washed via stormwater beyond the waste management unit—setbacks should recognize this likelihood. Measuring from the property boundary avoids the problem of pits inadvertently expanding beyond their permitted bounds. (Buffer zones sufficient to allow equipment to operate are also necessary as well.)

Commission Shift proposes that setbacks be required for at least the following receptors:

- surface water, including wetlands
- public water system well or intake
- domestic water well or irrigation water well
- 100-year flood plain
- residential, commercial, or public buildings; schools, hospitals, institutions, public parks and churches
- other sensitive areas, as defined in § 4.110(79).

Setbacks should be based on the risks and nuisances associated with the particular oil and gas waste operation. The risk of an operation will depend on the type and volume of waste handled and how long it will be at that location. For example, pits that are used for days or weeks with low levels of pollutants would typically be less cause for concern than permanent disposal landfills. Instead of

disposal-of-exploration-and-production-waste-generated-from-drilling-and-production-of-oil-and-gas-wells/section-xix-507-location-criteria

164 §4.264(a) (off-lease commercial recycling) states "A pit permitted under this division shall not be located: (1) where there has been observable groundwater within 100 feet of the ground surface unless the pit design includes a geosynthetic clay liner (GCL); (2) within a sensitive area as defined by §4.204 of this title (relating to Definitions); (3) within 300 feet of surface water, domestic supply wells, or irrigation water wells; (4) within 500 feet of any public water system wells or intakes; (5) **within 1,000 feet of a permanent residence, school, hospital, institution or church** in existence at the time of the initial permitting; (6) **within 500 feet of a wetland**; or (7) within a 100-year floodplain"

165 These communities have experience problems at greater distances than those proposed in these rules.

166 EJScreen is EPA's Environmental Justice Screening and Mapping Tool. https://www.epa.gov/ejscreen

regulating based on whether an operation is authorized or not, the Commission should propose a (potentially three-tiered) system of setbacks tied to volume, pollutant level, and duration of operation and waste storage. To be clear the proposed setback distances in § 4.150 are not sufficient for permitted or commercial operations—communities have been affected well beyond these distances

Commission Shift generally supports the language in subsection (b) that if at any time a pit that no longer meets the requirements for a permit-by-rule, the operator must apply for a permit. However, Commission Shift urges the Commission to require an application to be filed promptly, "within 30 days."

Commission Shift supports the requirement in subsection (f) that in the event of an unauthorized release, the operator must take any measures necessary to stop or control the release. However, Commission Shift urges the Commission to also require the operator to notify the public as well within 24 hours of the release. As such, the Commission should adopt the following changes:

> (f) In the event of an unauthorized release of oil and gas waste, treated fluid, or other substances from any pit permitted by this subchapter, the operator shall take immediate corrective action and any measures necessary to stop or control the release and report the release to the District Office and the public within 24 hours.

§4.151. Design and Construction of Pits Authorized by Permit. Page 62

Again, Commission Shift urges the Commission to require freeboard on all pits to be two feet plus a volume sufficient to contain the 25-year, 24-hour rainfall event:

> (b)(2) Freeboard. Unless otherwise required by permit or rule, the permittee shall maintain all pits such that each pit maintains a freeboard of at least two feet plus a volume sufficient to contain the 25-year, 24-hour rainfall event.

As for the installation procedures for liner (subsection b(3)), Commission Shift refers the Commission to its comments in Division 3. In addition, the Commission rule should require dual hot wedge seams for all permitted pits that are required to be lined with synthetic liners. A standard hot wedge creates a single uniform-width seam, while a dual (or split) hot wedge forms two parallel seams with a uniform unbounded space between them. The dual hot wedge seam is considered in the literature to be the preferred seaming method for all thermoplastic geomembranes.

§4.152. Monitoring of Pits Authorized by Permit. Page 63

Commission Shift urges the Commission to give operators more guidance on how to document and conduct the annual inspection of a pit liner so that the integrity of the liner is actually reviewed. Liner integrity cannot be determined from photographs taken at a distance, yet the current language would allow it. Commission Shift suggests adding the following language to 4.152(a)(1):

> (1) The permittee shall empty the pit and conduct a visual inspection on an annual basis. The permittee shall photograph the interior of the and otherwise record each inspection. Photographs shall include liner conditions at all welded seams, appurtenances, and prior repairs. The annual inspection photographs shall include

> field notes that explain where each photograph was taken and what was observed. The annual inspection shall include documentation of any liner wrinkles, tears, and other indicators of liner failure. The permittee shall maintain the photographs, documentation, and records from each inspection for the life of the pit.

Commission Shift is also troubled by the action leakage rates and monitoring plan described in 4.152(b)(1). These rules codify the existing amount of leakage allowed from some permitted facilities, but when examined, these rates make little practical sense and the Commission has provided no reasoning for these thresholds.[167] In addition, solid waste would presumably have no fluids in it, and indeed be able to retain rainfall in most circumstances, so any leakage at all would presumably represent a liner failure.

Commission Shift also requests clarification on section (b)(1) regarding what shall constitute a liner failure. This section appears to include drafting errors, especially when (A)-(C) are read in context with (D):

> (1) Failure of the primary liner in a double liner and leak detection system occurs if:
>
> (A) a volume of fluid is withdrawn from the leak detection system that is greater than the calculated action leakage rate, the standard action leakage rate of 1,000 gallons per acre per day (GPAD) for pits that manage fluid waste, or 100 gallons per acre per day (GPAD) for pits that manage solid oil and gas wastes;
>
> (B) any failure in the leak detection and return system or any component of the system occurs;
>
> (C) any detected damage to or leakage from the secondary liner occurs; or
>
> (D) the volume of fluid withdrawn from a pit with a leakage detection system exceeds the volume stated in the permit for 15 consecutive days or the weekly reported volume exceeds the volume stated in permit at least once a month for three consecutive months, in which case the operator shall notify the appropriate District Office and the Technical Permitting Section.

It would make sense for items (A), (B),and (C) to be thresholds for failure (as long as the allowable action leakage rate was lowered); however (D) seems to be redundant in light of (A)—any exceedance in (D) should have triggered action under (A). Barring any contrary explanation by the Commission, Commission Shift recommends that (D) be moved into its own section or omitted entirely. Any time the criteria in (A)-(C) are met, the operator should be required to notify Technical Permitting within 24 hours and immediately cease operations until the pit is emptied and repaired, as (b)(3) would require. This could be accomplished with the following language:

> (1) In the event of failure of the primary liner in a double liner and leak detection system, the operator shall notify the appropriate District Office and the Technical Permitting Section within 24 hours and immediately cease operations until the pit is emptied an

[167] If these values have been pulled from other studies, the Commission must ensure that the assumptions used in the literature are appropriate for the pits it seeks to regulate in this rule. For example, leakage rates will vary based on the head of liquid in the pit and in the leak detection system, as well as the permeability of all materials involved.

> repaired according to (b)(3). Failure of the primary liner in a double liner and leak detection system occurs if:
>
> (A) a volume of fluid is withdrawn from the leak detection system that is greater than the calculated action leakage rate, the standard action leakage rate of 1,000 gallons per acre per day (GPAD) for pits that manage fluid waste, or 100 gallons per acre per day (GPAD) for pits that manage solid oil and gas wastes;
>
> (B) any failure in the leak detection and return system or any component of the system occurs; or
>
> (C) any detected damage to or leakage from the secondary liner occurs; ~~or~~
>
> ~~(D) the volume of fluid withdrawn from a pit with a leakage detection system exceeds the volume stated in the permit for 15 consecutive days or the weekly reported volume exceeds the volume stated in permit at least once a month for three consecutive months, in which case the operator shall notify.~~

Section (b)(1)(D) is additionally ambiguous because it's unclear what "the volume of fluid withdrawn from a pit with a leakage detection system" means—is it the volume withdrawn from the leakage detection system, as in A? Or is it the volume of liquid removed in general from the pit through normal operation and use of the pit? In addition, not all pits are used every day—so section (D), which appears to allow weekly monitoring to calculate a daily leakage rate—may mask the identification of large leaks if the leakage rate is monitored infrequently. Prior to formal rulemaking, the Commission should clarify subsection (b)(1) as a whole.

Additionally, section (b)(3)(C) should include a requirement that the operator file a report describing the incident and the remedy taken, including an explanation for what happened to the waste emptied from the pit once the liner leak was found. Reporting this information is important so that the Commission and public can confirm that the waste was disposed of properly.

§4.153. Commercial Disposal Pits. Page 64

Commission Shift understands that section (a) was added as part of a legislative mandate for the 10-year flood history of a site to be considered during site approval. Commission Shift is very concerned that the Commission will not commit to wholeheartedly incorporating this factor into its analysis of an application—as written the section only requires documentation of a "good-faith" investigation of whether an area is flood-prone but it does not commit the agency to considering this information in its analysis. It also does not list what investigations would be considered good-faith. The Commission should modify this section accordingly.

Subsection c ("Closure") is problematically worded because it relies on a non-parallel list, rendering the subsection confusing.[168] Commission Shift suggests that subsection (c) be slightly reworded to clarify that the default post-closure monitoring period is at a minimum ten[169] (not five)

[168] https://blog.harwardcommunications.com/2021/08/31/what-is-parallel-structure-and-why-does-it-matter/

[169] For more details on why a minimum of ten years is more appropriate, see the comments on § 4.114.

years for any commercial disposal pit or facility where a commercial disposal pit is located, and that if it is not set to be ten years by the permit, the Director still retains discretion to implement a longer monitoring period if after-the-fact circumstances indicate a longer period is necessary. That intent could be conveyed with the following revision:

> Unless otherwise required by permit or if the Director determines that such post-closure monitoring is necessary to prevent pollution, a post-closure monitoring period of no less than ~~five~~ ten years is required for any commercial disposal pit~~,~~ and a facility where a commercial disposal pit is located~~, or if the Director determines that such post-closure monitoring is necessary to prevent pollution~~."

7. DIVISION 7 ADDITIONAL REQUIREMENTS FOR LANDFARMING

Commission Shift requests that the Commission consider whether these rules incorporate all types of land farming, land application, and land spreading that are used in the oil and gas industry, including those that the Commission currently regulates.[170] Practices that may be appropriate for disposal on-lease may not be appropriate off-lease and at commercial facilities and so should be prohibited, and vice versa. As part of this rulemaking, the Commission must ensure that landfarms that have been allowed to violate permits and cause pollution in the past will no longer be allowed to

[170] The Commission's website (https://www.rrc.texas.gov/oil-and-gas/applications-and-permits/environmental-permit-types/landfarming-landtreatment-and-land-application-facilities/) describes the activities regulated as follows:
There are three types of permitted land-spreading facilities:

> *Landfarming facilities* can treat and dispose of only freshwater-based drilling fluids and associated cuttings.
> *Landtreatment facilities* can treat and dispose of oil and gas wastes including oil-based drilling fluids and oil-impacted soils.
> *Land application permits* are an alternative to discharge of fluid wastes. Gas plant effluent or low-chloride produced water may be applied to a controlled area via sprinkler or other irrigation systems.

Land-spreading utilizes the physical, chemical and biological capabilities of the soil-plant system to control waste migration and to provide a safe means of disposal without impairing the potential of the land for future use. Land-spreading facilities should be located on fine or medium grained soil with a thickness of at least 20 inches and a slope of less than five percent. Stormwater runoff must be controlled by either natural drainage features or by diversion structures. Land-spreading facilities should not be located in any area prone to flooding.
Landfarming of the following oil and gas wastes is authorized without a permit by Statewide Rule 8(d)(3), provided the wastes are disposed of on the same oil or gas lease where they are generated, and provided written consent of the surface owner of the tract where the landfarming will occur is obtained:

> -water base drilling fluids with a chloride concentration of 3000 mg/l or less;
> -drill cuttings, sands and silts obtained while using water base drilling fluids with a chloride concentration of 3000 mg/l or less; and
> -wash water used for cleaning drill pipe and other equipment at the well site.

Other landfarming operations require a permit. Any facility land-applying oil-based drilling fluids and associated cuttings will require a permit."

do so.[171] It should also address why many of the guidelines it currently uses in permitting these facilities (including closure standards) have not been incorporated here.[172]

In reviewing whether the Commission should add additional rules to regulate different types of landfarming practices, the Commission should show its work by including an analysis of the landfarming and land spreading practices in adjacent states for wastes with similar waste characterization profiles. It appears that with this rulemaking, the Commission will be regulating in- or on-ground disposal methods, both which envision that the land will be suitable for agriculture and other such purposes in the future. The biological and chemical processes relied on to treat waste in this way can be temperamental and require in-depth understanding of the waste, receiving soil, and climatic conditions. The Commission must therefore ensure that it requires careful testing of the incoming waste, receiving soil, and treated material, as well as sufficient monitoring during the treatment process in order to protect human and environmental health. Commission Shift strongly urges to include more detail throughout this Division.

§4.160. Additional Requirements for Landfarming Permits. Page 66

Commission Shift suggests that this section be edited to refer to "Divisions 4-6" as applying to landfarms, as some may be commercial facilities and the setbacks applicable to permitted pits (§4.150) should also apply to landfarms.

§4.161 Design and Construction Requirements for Landfarming Permits. Page 66

Overall Commission Shift has serious concerns that this Division lacks sufficient detail for human and environmental health to be protected in addition to surface waters, as is required by 4.161(a)(1)(B). To ensure that these setbacks are maintained, the applicant should be required to submit a topographic map and aerial photos (e.g., from Google Earth) to confirm that all applicable setbacks are addressed. This requirement could be included as follows:

[171] Ex. 1 Fehling, Dave. How 'Landfarms' For Disposing Drilling Waste Are Causing Problems In Texas (2012). https://stateimpact.npr.org/texas/2012/11/12/landfarms-for-disposing-drilling-waste-causing-problems-in-texas/ ("The Texas Environmental Enforcement Task Force, run out of the Travis County District Attorney's Office but with statewide jurisdiction, recently won a criminal conviction and a $1.35 million fine against the company that had operated the landfarm, Pemco Services, Inc. "For over a decade the company was out of compliance with their permit and there was little done to regulate them," said Patricia Robertson, the task force's environmental crimes prosecutor. Robertson credits the efforts of a couple officers from Texas Parks and Wildlife for investigating the site and then alerting her office. The task force would later allege that from 2002 to 2009, a total of nearly 57 million gallons of drilling fluids were deposited on the landfarm in violation of the permit issued by the Railroad Commission. Yet the Commission, which has the power to take "enforcement action," never did. In 2010, the Texas Environmental Enforcement Task Force got search warrants to go on the site and take water samples. Prosecutors said lab tests confirmed the site was causing water pollution. They headed to court and eventually got a conviction and then earlier this month, a judge in Travis County imposed the big fine on Pemco Services, Inc.")

[172] Application Information for Landfarm and Landtreatment Permits. https://www.rrc.texas.gov/oil-and-gas/applications-and-permits/environmental-permit-types/landfarming-landtreatment-and-land-application-facilities/landfarm-and-landtreatment-permit-application/

(a)(4) The applicant shall submit a topographic map and aerial photographs that show the facility boundary, location of all landfarm areas, any drainage features or surface waters, and all setbacks required in Divisions 4 through 7.

Commission Shift urges the Commission to require landfarm applicants to collect and submit more data with their applications, beyond minimal requirements such as those in 4.161(a) that "The applicant shall submit information to demonstrate that the area has at least 20 inches of tillable soil *that is suitable for the application, treatment, and disposal of oil and gas waste*"[173] and those in 4.162(a) that require the estimated chloride concentration of waste to be accepted to be included in the application. Detailed soil sampling is necessary for the Commission to evaluate the application, and also should be conducted prior to each delivery of waste being tilled into the soil, as is recommended by a variety of groups.

The 2022 STRONGER Guidelines state "Soil analyses should be performed prior to landspreading and again upon closure of the Site,"[174] and other expert groups agree.[175] A 2009 report from Texas A&M summarizes the sampling that should take place before the land application of fluids, emphasizing that no single measurement (like chloride) is sufficient to manage disposal: [176]

> The decision to land apply drilling fluids should be based on the chemical composition of the drilling fluid, and the amount and characteristics of the land area available. The first step is to obtain a chemical analysis of the drilling fluid and a representative (composite) sample of the native soil from the proposed land application area. No single measurement, such as a simple chloride analysis, is sufficient to properly evaluate and manage drilling fluid disposal. A thorough analysis should include the following measurements for both the drilling fluid and native soil unless otherwise specified:
>
> 1. **Total salts** – measured as the electrical conductivity (EC) of the saturated paste extract and reported in parts per million (ppm) or millimhos per cm (mmhos/cm).
>
> 2. **Extractable individual ions** – calcium, magnesium, sodium, boron, chloride, and sulfate-sulfur measured in the saturated paste extract and reported in milligrams per kilogram (mg/kg) or ppm.
>
> 3. **Sodium Adsorption Ratio (SAR)** – calculated from the saturated paste analyses for calcium, magnesium, and sodium.

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[173] Commission Shift also requests that prior to formal rulemaking, the Commission explains why 20-inches has been used—if it is a limitation on plow depth, it should be clarified as such.

[174] Ex. 11 2022 STRONGER Guidelines at 45. https://www.strongerinc.org/wp-content/uploads/2022/07/2022-Edition-STRONGER-Guidelines.pdf

[175] Commission Shift urges the Commission to require testing of the E&P waste prior to land treatment and the RRC should develop a standard loading rate. (2000 Guidelines 5.6.3.d and 5.6.3.i.)

[176] Ex. 39 McFarland, M.L. et al. Land Application of Drilling Fluids: Landowner Considerations, Texas AgriLife Extension Service (Aug. 2009) at 4 http://soiltesting.tamu.edu/publications/SCS-2009-08.pdf. The report goes on to state: "A qualified professional can utilize the results of these tests to determine if land application is appropriate for a particular situation. If so, they can provide the proper rate of application (barrels per acre, tons per acre, or inches of depth) of drilling fluid so that the process does not cause long-term adverse effects on soil properties. These results also can be used to determine if additional soil amendments may be needed to promote treatment of the waste. For example, gypsum (calcium sulfate) may be recommended to offset high levels of sodium in the drilling fluid and prevent problems with soil structure. In other cases, nutrients are applied to support the growth of soil microbes capable of decomposing hydrocarbons, and to enhance plant growth for site recovery." *Id.* at 5.

4. **Total heavy metals** – arsenic, barium, chromium, copper, lead, nickel, and zinc reported in mg/kg.

5. **Total petroleum hydrocarbons (TPH)** – drilling fluid only, reported in mg/kg.

6. **Routine + micronutrient soil nutrient test** – pH, and extractable nitrate-nitrogen, phosphorus, potassium, calcium, magnesium, sodium, sulfur, copper, iron, manganese, and zinc.

7. **Soil texture** – native soil only.

8. **Cation exchange** capacity – native soil only.

The Commission should add these sampling requirements to § 4.161(a)(2) as a list of sampling information that "the applicant shall submit" as subitems (A) – (H) plus any additional analysis that the Director states is necessary to determine that the receiving land is suitable for landfarming. The Commission requires these parameters to be analyzed for wells;[177] monitoring the integrity of authorized pits —or landfarming units that require permits- should be no different.

The Commission should also consider setting concrete limits to the type of waste that can be landfarmed. In general, the more complex a hydrocarbon is, the longer it takes to biodegrade during landfarming. EPA and other groups provide details on the constituents expected in oil and gas wastes and the capacity of landfarming to treat those wastes—the Commission should consider these references when developing its own standards.[178]

Temperature is also an important variable in ensuring that the receiving soil will be able to handle the pollutants in the waste (including in how it effects breakdown and the moisture content of the soil). As Texas warms,[179] the Commission should evaluate whether certain parts of the state are no longer suitable for landfarming, or whether landfarming should be restricted to only certain months of the year.

In addition, the various soil amendments and microbes used to treat soil can lead to their own set of concerns.[180] The Commission should require applicants to not only document the amendments used (as in 4.162) but also defend how those amendments will not lead to further pollution.

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[177] See 4.114(h)(7) "The wells shall be monitored and/or sampled for the following parameters: the static water level, pH, and ***concentrations of benzene, total petroleum hydrocarbons, total dissolved solids, soluble cations (calcium, magnesium, potassium, and sodium), and soluble anions (bromides, carbonates, chlorides, nitrates, and sulfates)***."

[178] Ex. 40 How To Evaluate Alternative Cleanup Technologies For Underground Storage Tank Sites (2017, USEPA) Link: https://www.epa.gov/sites/default/files/2014-03/documents/tum_ch5.pdf ; Petroleum Production on Agricultural Lands in Texas: Managing Risks and Opportunities. https://agrilife.org/texasaglaw/files/2018/12/Petroleum-Production-on-Agricultural-Lands-in-Texas.pdf

[179] See e.g., Ex. 41 Five hottest days in Texas history. (August 2023) https://www.saveonenergy.com/resources/five-hottest-days-texas-history/ ; Ex. 42 Is there a limit to how hot it can get in West Texas? (June 2023) https://www.newswest9.com/article/weather/how-hot-can-it-get-in-west-texas/513-8f116dc3-fd51-4af6-91bc-a8b0fe9d1d93

[180] Soil amendments—which is not defined in these rules—can be a catchall phrase that might include char, byproducts of gasification/pyrolysis; digester solids; some types of biosolids; poultry litter; etc.

As for **subsection (b)**, the rules do not specify that berms should be properly maintained to prevent erosion and capture contaminated stormwater runoff. The Commission could incorporate such requirements with the following language:

> (b) Berm construction. All berms shall be constructed and maintained:
>
> (1) to fully enclose each landfarm area in a manner that shall prevent erosion and stormwater run-on and run-off

As discussed in its comments on § 4.150, Commission Shift also believes that the setbacks and buffers for landfarms (like facilities with permitted pits) should be increased beyond those proposed. Commission Shift also urges the Commission to categorically deny landfarm permits when shallow groundwater is present.[181] Groundwater monitoring should also continue to be a requirement unless on-site borings taken to 100 feet demonstrate no shallow groundwater underlies the proposed location.[182] The Commission should also set a maximum limit as to the size of each landfarm cell[183] —typically the equipment used in landfarming is only effective at smaller sizes, above which there is nonuniform application of waste, and the potential for overapplication, ponding, and hotspots. And given that only one sample is required per acre, it is highly unlikely that such hotspots would be identified.

§4.162. Operating Requirements for Landfarming Permits. Page 67

Commission Shift reiterates its concerns raised in § 4.161 that more than just the chloride concentration of the waste must be considered, as section (a) would envision.

Commission Shift also questions why section (a) is left as open-ended as it is. It appears that the decision as to whether or not a landfarm should be permitted will be largely left up to Technical Permitting staff to develop guidelines outside the notice-and-comment rulemaking process. Again Commission Shift reiterates its request that the Commission provide more details on the landfarming process and how it will ensure that landfarming does not endanger human or environmental health.

§4.163. Monitoring. Page 68

[181] New Mexico, for example, prohibits the landfarming of waste where groundwater is located less than 50 feet below the lowest elevation at which the operator will place oil field waste, and wastes with a chloride concentration that exceeds 500 mg/kg is prohibited at sites with groundwater within 100 feet. See 19.15.36.13(A)(2)-(3).

[182] This requirement from the Commission's current guidelines appears to have disappeared from this draft. See Application Information for Landfarm and Landtreatment Permits. https://www.rrc.texas.gov/oil-and-gas/applications-and-permits/environmental-permit-types/landfarming-landtreatment-and-land-application-facilities/landfarm-and-landtreatment-permit-application/

[183] There is not a complete accounting of all landfarming and land applications in Texas currently, but land application facilities that EPA has identified in Texas range between 12 acres divided into 4 separate cells and 517 acres divided into 17 cells. Management of Exploration, Development and Production Wastes: Factors Informing a Decision on the Need for Regulatory Action ("EPA's Need for Action"), EPA (April 2019) at 4-9. https://www.epa.gov/sites/default/files/2019-04/documents/management_of_exploration_development_and_production_wastes_4-23-19.pdf

Commission Shift is deeply concerned that the minimal number of samples required by these rules will not ensure that the waste is fully treated. As drafted, as little as one composite sample per acre is required for each of the three compliance zones. Denser sampling should be required. In addition, the Commission should explicitly require the following parameters be monitored during each event:

> Monitoring of landfarm treatment cells should include pH, moisture content, bacterial population (heterotrophic aerobes), nutrient content, and concentrations of pollutants that are being treated (TPH, heavy metals).

Commission Shift also urges the Commission to develop and publish expected sampling and analysis limitations for each zone. Sampling should also be conducted by independent third-parties and analyzed by accredited laboratories, as such Commission Shift suggests the following revision:

> (c) The operator shall have ~~analyze~~ samples analyzed from each active cell according to the analysis requirements specified in the permit and §4.124(e)(2)-(3).

Commission Shift also opposes allowing operators to continue to add waste to a cell after sampling shows exceedances for pollutants. The cell should be temporarily closed from accepting new waste until the waste no longer exceeds recommended parameters. As such, the following revision should be made:

> (d) (4) If the parcel exceeds the limitation after ~~six months of~~ sampling, that plot is not authorized to accept additional waste until a sample analysis does not exceed the particular limitation.

§4.164. Closure. Page 69

Commission Shift notes that there does not appear to be a procedure in place for public notice to adjacent landowners (and property owner) or the general public that a closure plan has been submitted for review and approval. There is also no mention of sampling groundwater to determine if pollution occurred that needs to be remediated. If that is because the closure requirements in Divisions 4-6 apply (including § 4.132), the Commission should reiterate that here.

Likewise, Commission Shift notes that closure sampling should also include independent third-party sampling and testing of the soil to verify site can support future vegetation. The Commission has stated in the past that this is required procedure, but this requirement does not appear to be included in the proposed rule.[184]

Closure should also include sampling outside of the designated landfarm cells, to ensure that no waste has migrated outside the treatment cell or has not persisted in other areas. This is currently a similar requirement in the Surface Waste Management Manual, but it does not appear to have been

[184] Ex. 1, Fehling, David. How 'Landfarms' For Disposing Drilling Waste Are Causing Problems In Texas. NPR. (Nov. 12, 2012). https://stateimpact.npr.org/texas/2012/11/12/landfarms-for-disposing-drilling-waste-causing-problems-in-texas/

incorporated into this rulemaking.[185] Finally, Commission Shift notes that the Commission has published the closure parameters that it typically requires landfarms to meet. However, it has not proposed those for adoption in this rulemaking. The Commission should clarify why it has declined to do so and whether those will continue to be the closure levels that facilities must meet.[186]

8. DIVISION 8 ADDITIONAL REQUIREMENTS FOR RECLAMATION PLANTS

Commission Shift understands that with this rulemaking, the Commission is moving the requirements of Rule 57 into Subchapter A. However, it appears that the Commission has not moved all of the definitions into § 4.110 yet. For example, there is no definition for "authorized person" in § 4.110, yet it is a term used throughout Division 8 and one that was defined in Rule 57.

Commission Shift also urges the Commission to ensure that reclamation plants operate with the strictest of standards so that environmental and human health is protected. Reclamation plants handle a vast variety of oil and gas waste, including the waste from oil and gas processing plants and underground storage of gas and hydrocarbons —basically only excluding RCRA hazardous waste. In a typical reclamation plant, incoming wastes are separated into water, oil and soild fractions by means of thermal, physical and chemical processes. Waste is kept in a variety of holding areas during the process, some open air, some in tanks. There is potential for noxious vapors and malodors with such facilities—air permits may be required from TCEQ.[187] Given the complexity of operations at reclamation plants it is essential that the waste is characterized by laboratory analysis and that surface and subsurface water is protected from possible contamination.

§4.170. Additional Requirements for Reclamation Plants. Page 70

Commission Shift requests that the Commission provide an example as to how many facilities might fall within subsection (a)(3), which exempts certain facilities from monthly reporting. The subsection allows a hearing only if the application is denied and does not contemplate notice or input from surrounding landowners. All interested parties—community members included—should be allowed to participate in that permitting process, and appeal administratively if necessary. This one-sided appeals right is unfair everywhere it appears, including in subsection §4.171(d) and (e)—and

[185] https://www.rrc.texas.gov/oil-and-gas/applications-and-permits/environmental-permit-types/landfarming-landtreatment-and-land-application-facilities/landfarm-and-landtreatment-permit-application/ (Detailed plans for closing the site when land-spreading operations cease, include plans for closing any boreholes used for vadose zone or groundwater monitoring, removing dikes, contouring, and reseeding. Also include plans for sampling and analyses of areas other than remediated waste in treatment cells (e.g., temporary holding cells, treatment cells from which the waste has been removed, leachate collection sumps, etc.) Provide an estimate for the amount of time required to close the site).

[186] Ex. 43 Railroad Commission of Texas (RRC). Version Dated January 24, 2019. Closure Table 2 Landfarm, Landtreatment, and Land Application permits: Standard Soil Sampling Closure Parameters. https://portalvhdskzlfb8q9lqr9.blob.core.windows.net/media/49968/standard_closure_parameters-lf.pdf

[187] Though if these are "permitted-by-rule" there may be minimal scrutiny on the unique hazards of each site and nearby sensitive receptors.

should be altered to state: “The Commission’s decision on a request for authorization may be appealed by any interested person.”[188]

As for the language in subsection (a)(6), Commission Shift is encouraged to see that all reclamation plants will be regulated as commercial facilities regardless of the definition of commercial that is adopted in section 4.110.

However, Commission Shift strenuously objects to the lengthy grandfathering of reclamation plants that were permitted prior to this rulemaking, as subsection (a)(7) would allow. Permits issued prior to this new rulemaking should expire one year after the effective date of the rulemaking, not five years. A facility can always seek to renew its permit before the one-year period has elapsed.

As for subsection (b), this subsection states that ***applicants*** and ***permittees*** operating reclamation plants must comply with Divisions 4-6. The Commission should also confirm that the ***agency*** itself will also follow the permit procedures as well, including the procedures in § 4.134 with respect to determining completeness prior to approval. In addition, Commission Shift notes that the Commission’s current guidelines for reclamation plants is much more detailed than the rules proposed here.[189] The Commission should incorporate at least a similar level of detail into this rulemaking so that the public may weigh in.

§4.171. General Permit Provisions. Page 71

Subsection (b) represents a fundamental change in Commission practices—previously a permit to operate a reclamation plant was not transferable, and the Commission required the new operator to obtain a new permit by submitting a complete application (allowing a renewed opportunity for public participation).[190] ***This should have been the practice that the Commission adopted in this rulemaking for all facilities.*** At a minimum, this practice should be preserved for reclamation plants. Commission Shift strongly opposes this shift to water down the availability for public participation in the renewal, transfer, and amendment process for reclamation plants even if the procedures for public notice in § 4.133 are required (for more on Commission Shift’s concerns related to renewals, transfers, and amendments, see § 4.122).

Commission Shift supports the mandatory reporting of Division 10 violations within 24 hours of occurrence (subsection (c)). However, the violation should also be reported to the Director and to the public at the same time.

[188] Instead of: “~~If the request for authorization is denied, the applicant may request a hearing~~.” 4.170(a); 4.171(3),(d),(e). See also §4.135(a).

[189] See https://www.rrc.texas.gov/oil-and-gas/applications-and-permits/environmental-permit-types/reclamation-plants/

[190] Id. The Commission was also clear that “The reclamation permit may be cancelled if the facility has been inactive for 12 months” and that “Once an application package has been submitted, only minor modifications or staff-recommended amendments will be accepted during the review process. If the original application is fundamentally revised, the application must be withdrawn, and a new application may be filed.”

As for subsection (e), the Commission should require lab analysis be completed for any waste that is being received by a reclamation plant. Commission Shift also questions what sort of waste an operator would send to a reclamation plant that is neither "tank bottoms or other oil and gas waste," as subsection (e) describes. Such waste should absolutely be tested to confirm that it is not hazardous and that it is compatible with the reclamation processes used onsite. This could be accomplished by the following suggested language:

> (e) All waste materials received shall be tested by laboratory analysis according to the requirements of § 4.124(e)(3)-(4). The receipt of any waste materials other than tank bottoms or other oil and gas wastes shall be authorized in writing by the Commission prior to receipt. The Commission ~~may~~ shall require the reclamation plant operator to submit an laboratory analysis of the waste materials prior to a determination of whether to authorize receipt. If the request for authorization is denied, the applicant may request a hearing.

§4.173. Minimum Permit Provisions for Reporting. Page 73

As Commission Shift's comments on § 4.108 reflect, Commission Shift urges the Commission to establish—within one year of the effective date of this rulemaking—an electronic filing system for reclamation plant reports that is public-facing, and thus urges the Commission to change the "may" to a "shall" in subsection b:

> (b) The Commission ~~may~~ shall establish a form or electronic system for filing monthly reports for reclamation plants.

As for subsection (c), Commission Shift suggests that the Commission reexamine the language in (c)(1) and (c)(2). It is unclear if the intent is to differentiate based on whether the waste comes from a pipeline facility or from other sources (except (c)(2) also includes pipeline facilities) or if it is to differentiate between tank bottoms and "other" waste (except (c)(2) also addresses waste from "tanks"). More clarity would help operators comply and the public understand the rules.

For subsection (d), Commission Shift encourages the Commission to always require a laboratory analysis of the disposable material to be performed before approving a minor permit ("may" should be replaced with "shall" in the last sentence of (d)). Reference should also be made to § 4.124(e)(3)-(4), which describes how laboratory analysis and NORM sampling should be conducted.

9. DIVISION 9 MISCELLANEOUS PERMITS

§4.180. Activities Permitted as Miscellaneous Permits. Page 74

Commission Shift is greatly concerned that Division 9 creates unnecessary loopholes for waste management operations to take place without sufficient safeguards for human health and the environment and without the safeguards that properly conducted notice-and-comment rulemaking can provide. For many of the permits in this Division, the Commission is already operating under more detailed guidance (readily available on its website) that it has chosen not to incorporate into this rulemaking, begging the questions of whether that guidance will continue to apply and why it has not been subjected to notice-and-comment rulemaking. Especially concerning is the fact that Division 9 waives the requirements set by Divisions 4-8, which even if flawed, provide more transparency than the guidelines.[191] Commission Shift urges the Commission to delete the last line of § 4.180[192] and the sections § 4.183, § 4.184 and § 4.185 in their entirety.

§4.181. Emergency Permits. Page 74

Commission Shift request clarification as to whether emergency permits might be granted for the purpose of “protecting public health, public safety, and the environment,”[193] in addition if needed to prevent waste and pollution of surface or subsurface water.[194] Commission Shift urges the Commission to confirm during the rulemaking that emergency permits will not be granted for convenience or any other reason. If the Commission insists on waiving notice for emergency permits, it should at a minimum require that the permit application and all reports be made publicly available contemporaneous with their filing (subsection (b)), including any oral applications made or permits rendered (subsection (c)). The Director’s reasoning for alterations to the permit should also be made publicly available for review (subsection (d)). If it is truly an emergency, then the potentially affected public has a right-to-know and should be included in the permit process.

Commission Shift also is of the opinion that permits issued without notice-and-comment should expire after 15 days, not 30 days. In comparison, emergency orders of the Commission must expire after 15 days. Tex. Nat. Res. Code § 85.206(a)-(b)[195]. The Commission should not by rule allow emergency permits issued without opportunity for notice-and-comment to last for a longer period than what the Legislature itself set for the Commission’s emergency orders.

Finally, Commission Shift objects to District Directors being granted authority to issue emergency permits. The decision to grant an emergency permit should be centralized with the Technical Permitting Staff so that what constitutes an emergency can be standardized and consistent. Only when Technical Permitting is not available due to the nature of the emergency, and after the District has attempted to contact Technical Permitting, should the District have limited authority to act on an emergency permit. And if it has not already, the Technical Section in Austin should develop a

[191] § 4.180 states that “Unless otherwise specified in this division or by the Director, the requirements of Divisions 4 through 8 of this subchapter do not apply to activities permitted under this division.”

[192] I.e., the Commission should delete the line that states: ~~“Unless otherwise specified in this division or by the Director, the requirements of Divisions 4 through 8 of this subchapter do not apply to activities permitted under this division.”~~ By ***including*** this very strong language, the Commission makes itself vulnerable to an arbitrary-and-capricious challenge by an applicant if later on the Commission tries to apply the requirements of Division 4 through 8 to a Division 9 permit.

[193] As is enumerated in § 4.101(b).

[194] As is proposed in § 4.181(a).

[195] “The emergency order shall remain in force no longer than 15 days from its effective date.” (b).

(publicly available) standardized list of what constitutes appropriate use of an emergency permit and provide training to District Offices on how to make good decisions in the event of an emergency.

§4.182. Minor Permits. Page 74

As it is with all of the permits in this Division, Commission Shift is frustrated by the lack of detail provided for notice-and-comment review of the minor permit program. Section 4.182 authorizes the issuance of permits for the storage or disposal of minor amounts of fluids or waste without defining what a minor amount is or limiting how often a minor permit may be issued for a single site (see section (a)). The Commission should define the threshold for "minor amount" and restrict operators from using minor permits as a means to avoid obtaining better scrutinized- and better-noticed permits.[196] As part of this rulemaking, the Commission should give examples of what it has considered to be a "minor amount" for each waste type. And going forward, applications for minor permits should be made publicly available and notice subject to the same rules as in Division 4.

Commission Shift requests clarification on the intent of subsection (c), which allows only minor permits issued without notice of application to be modified, suspended, or terminated at any time for good cause. It's unclear why the Commission grants itself this power only for non-noticed applications. The Commission should be able to modify, suspend, or terminate any permit, noticed or not, in the interest of the protection of human health and the environment.

Finally, Commission Shift objects to District Directors being granted authority to issue minor permits. The decision to grant a minor permit should be centralized with the Technical Permitting Staff so that what constitutes an minor amount (and how often minor permits can be used) can be standardized and the public can be informed. Likewise, Technical Permitting Staff should develop a standardized guidelines on issuing minor permits and seek public feedback on it before providing training to District Office on how to implement such a program.

§4.183. Miscellaneous Permits. Page 75

Commission Shift strongly believes that this section should not be added to these rules; any additional permitting schemes should go through notice-and-comment rulemaking.

[196] Commission Shift requests that the Commission clarify if its existing Guidelines for Minor Permits will remain in effect. See https://www.rrc.texas.gov/media/gyolztfy/2005guidelinesrule8.pdf The Commission's current guidelines state that: "no more than 5 minor permits, for no more than a total volume of 30,000 barrels from 5 wells, or 1 minor permit for waste from one well if the volume is greater than 30,000 barrels, will be issued for one disposal site." Id. at 4. Commission Shift is of the opinion that these limits far exceed what would be appropriate for a minor permit. According to the Commission, "Typically, these [minor] permits authorize a "one time" disposal of oil and gas waste. Minor permits are commonly issued for: One time, off-lease landfarming of water-based drilling fluid. One time, on-lease landtreatment of oily waste. Disposal of basic sediment by burial, or for reuse. Disposal of drilling fluid in casing or annulus. Hydrostatic Test Water Discharge Recycling of Domestic Wastewater" https://www.rrc.texas.gov/oil-and-gas/applications-and-permits/environmental-permit-types/minor-permits-hydrostatic-test-discharges-domestic-wastewater-and-other-permits/

Commission Shift strongly objects to section (a), which allows the Commission to establish permit requirements for "land application of high-quality produced water and land application of hydrostatic test waters not otherwise authorized by §4.111." This circumvents the public's ability to weigh in on what might be protective of human health and the environment. It also leaves undefined the phrase "high-quality produced water" and "hydrostatic test waters." Nor is "produced water" defined in Subchapter A. Furthermore, § 4.183 ignores Division 8's additional requirements for permitted landfarming.

Commission Shift strongly objects to the inclusion of subsection (b), which states:

> (b) For any waste management operation not otherwise authorized by rule or permit, the Director may establish permit requirements necessary to prevent pollution and protect human health and safety.

This looks to be yet another large loophole in which the Commission would be able to create an entirely new permitting system without engaging in the rulemaking process and without including the minimum protections set forth in Divisions 4-8. Any waste management operation not authorized by rule or permit should be prohibited. If there becomes a need to permit additional operations, the Commission should first conduct a rulemaking subject to notice-and-comment.

Transparent, participatory processes are necessary to ensure that the miscellaneous permitting program is not misused. In that vein, the Commission should make public the entities that requested that § 4.183 be included—from the hearings, it was clear that this program was requested at the behest of at least the Permian Basin Petroleum Association.[197]

§4.184. Permitted Recycling. Page 75

Commission Shift similarly objects to the grant of virtually unbounded authority for the Commission to create a permitting program for "non-commercial recycling not otherwise authorized by this subchapter."[198] As Commission Shift understands these rules, that would include all non-commercial recycling of solids and also the non-commercial recycling of fluids that is not covered by the definition in § 4.110(60)—in other words, ***any*** non-commercial recycling, with no limits on what recycling practices would look like or what waste streams might be used.

And by virtue of the proposed language in § 4.180, Divisions 5, 6, 7, and 8 would ***not*** apply to these permits—only Division 4 might be considered. But Division 4 contains ***no*** setbacks—that's all in Division 6 (§4.150). Division 6 also sets additional requirements on liners and what action is required if those liners leak. The Commission is unnecessarily limiting itself from fully protecting human and environmental health by tying its hands from considering Divisions 5-8. Subchapter B

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[197] Oral comments by PBPA spokesperson Michael Lozano on October 26, 2023 (thanking the Commission for including the sections on pilot programs and miscellaneous permits).

[198] § 4.184(a).

Division 7 at least sets ***some*** limits in the form of analytical limits on the recycling of solids (i.e., reuse of drill cuttings), but § 4.184 is totally silent in this and any other matter.

Any waste management operation not authorized by rule or permit should be prohibited. If there becomes a need to permit additional operations, the Commission should first conduct a rulemaking subject to notice-and-comment. Transparent, participatory processes are necessary to ensure that the miscellaneous permitting program is not misused. In that vein, the Commission should make public the entities that requested that § 4.184 be included.

§4.185. Pilot Programs. Page 75

In general, Commission Shift is very skeptical that with the proposed regulations alone the Commission will have sufficient oversight over the programs envisioned by § 4.185, which includes very few protections for human and environmental health, and as such objects to the inclusion of this section entirely.[199] As an initial matter, if "pilot programs" are limited to recycling only, that should be stated in the section heading (i.e., "pilot recycling programs").

The Commission's addition of subsection b during the drafting process does not provide sufficient additional clarification as to the purpose of such pilot programs nor ensure that they are regulated in a manner protective of human health and environment. (It is also not clear if it's an exclusive list of what would qualify for a pilot program.") As written, there seem to be very few limits on what a pilot program would consist of. Pilot programs should certainly not be exempt from the requirements of Divisions 4 through 8 of this subchapter; given the experimental, untested nature of new programs, it is especially important that the pilot programs be vetted by all interested persons, that notice be given, that application and permit materials be public, hearings be available, setbacks required and appeals routes clear. Before a permit is issued, the Commission should set metrics and goals for each program that indicate whether the program is working or not. That list should be drafted with public input given equal weight as industry input. (This is the only way to establish the public's trust that treated produced water can be reused in certain activities that are safe and protective of human health and the environment.) In addition, as is, subsection (c) does not provide guidance on ***how*** the Director is to decide whether a pilot program presents a threat of pollution and encourages recycling of oil and gas.

[199] Public Information Act requests reveal that the Commission has been working with industry on "a draft document entitled *Produced Water Recycling Framework for Pilot Study Authorization.* This document provides (1) an understanding of how RRC staff understands this challenge (that is, what staff wants industry to know), and (2) guidelines for industry on seeking authorization for pilot studies. This is RRC staff's current approach to pilot study authorization." It thus appears that the Commission will be planning on regulating at least some pilot programs through guidance, without the notice-and-comment protections of rulemaking. Commission Shift urges the Commission to include the public and other non-industry groups in the process of defining pilot programs so that human and environmental health considerations are fully included.

Any pilot program should require the program operator to file periodic operating and monitoring reports (at least quarterly) that are publicly available, and the Commission should be required to publicize its analysis on the program's process. It should also subject its decision to extend a pilot program to notice, hearing, and participation by all interested parties (and subsection (c)(2) should be revised accordingly to incorporate the requirements of Divisions 4-8). Subsection (c) also grants decision-making authority on program extensions to "the Commission" as opposed to the Director, without listing a role for Technical Permitting, as is seen elsewhere in the draft rules. The Commission should clarify whether the opinions and suggestions of technical staff are part of pilot project approvals (as they should be).

In any event, a pilot program should absolutely not be allowed to continue past the five years that traditional permits are allowed without a mandatory hearing and input and review by the public. Transparent, participatory processes are necessary to ensure that the pilot program process is not misused. In that vein, the Commission should make public the entities that requested that § 4.185 be included—from the hearings, it was clear that this program was requested at the behest of at least the Permian Basin Petroleum Association.[200]

10. DIVISION 10 REQUIREMENTS FOR OIL AND GAS WASTE TRANSPORTATION

§4.190. Oil and Gas Waste Characterization and Documentation. Page 76

Commission Shift supports the Commission's decision to issue rules on waste handling and documentation of waste manifests. East Texas communities in particular have struggled for years with waste haulers delivering mischaracterized wastes to facilities, and it is common knowledge that wastes from Louisiana are often preferentially disposed of in Texas landfills because Texas does less to prevent hazardous wastes from being sent to oil and gas waste landfills. There is still room for improvement in the proposed rules, however.

As an initial matter, Commission Shift is troubled that subsection (c) operates to make § 4.190 effective only once the Commission makes an electronic filing system available (without setting a deadline to do so). The Commission should set a one-year deadline for itself and outline for the public the steps it will be taking to acquire the funding for software, hardware, and qualified employees/contractors to create the electronic filing system, so that the public can be a vocal proponent for Commission to secure these critical pieces of a working electronic filing system.

Commission Shift assumes (and requests that the Commission clarify) that the waste profile information described in subsection (b)(4) would be made publicly available as part of the periodic

[200] Oral comments by PBPA spokesperson Michael Lozano on October 26, 2023 (thanking the Commission for including the sections on pilot programs and miscellaneous permits).

reporting required; if not, this subsection should be amended to require this information to be made publicly available.

For Commission Shift's comments on acceptable methods of waste characterization (mentioned in subsection (b)(1)(F)), see comments on §4.102. In any event, the following clause should be appended to the last sentence of subsection (b)(1)(F): "and include full laboratory analytical reports and corresponding chains of custody, performed in accordance as described in §4.124."

§4.191. Oil and Gas Waste Manifests. Page 77

For transparency, subsection (a)(2) should be revised to state that the "electronic manifest system . . . is accessible to the Commission, the public, and all parties . . ." Paper copies of manifests, if they are created, should also be made publicly available. Records also should be retained for more than a period of three years (see subsection (c))—this limited retention period dates back to an era in which records were paper, not electronic. Electronic storage is much cheaper than storing paper. Electronic files also take up much less space. Cradle-to-grave responsibility for waste can extend well past three years—the retention period should likewise extend beyond three years.[201]

§4.193. Oil and Gas Waste Haulers. Page 78

Commission Shift requests clarification why subsection (a) both prohibits the hauling of waste but then creates a carveout for "incidental" waste without defining what an incidental volume would be.

As for subsection (b)(1), Commission Shift suggests that for clarity there should be one subpart for inert waste and then a separate subpart for the much more critical asbestos, PCBs, and hazardous oil and gas waste, given the different risks associated with these categories of waste.

The application for a waste hauler should include information regarding the applicant and the applicant's vehicle's record, including whether the hauler has caused pollution or been involved in incidents of waste management discrepancies (§4.194(b)) that were reported for that waste hauler in the last seven years. Those with a history of waste discrepancies, accidents, or pollution should be prohibited from receiving permits. Commission Shift also questions whether the certification in (c)(3) stating that the vehicle has been appropriately designed should not instead be a certification from the manufacturer of the vehicle—given that the hauler likely does not have the design experience necessary to make such a certification. It could still be a certification that the hauler is obligated to obtain (just not obligated to make him or herself).

[201] The Commission could consider implementing a tiered system for retention of records—i.e., one that recognizes waste transport data has differing levels of long-term importance with respect to preserving cradle-to-grave data. The proposed rule lumps all waste transfer paperwork into one category of perceived importance.

Commission Shift also notes that the Waste Haulers Act additionally requires that waste haulers must provide an affidavit from the receiver that the hauler may use its facility. Commission Shift questions why this statutory requirement has been removed here.

§4.194. Recordkeeping. Page 81

Commission Shift is encouraged that the Commission will require operators to report waste management discrepancies (per subsection b).[202] This has been recommended to the Commission since at least 1993. Like all reporting done by operators, this information too should be made publicly available contemporaneously.

§4.195. Waste Originating Outside of Texas, Page 81

Commission Shift is encouraged that the Commission will require out-of-state waste to be identified more specifically by regulatory identifier and location, as Commission Shift suggested in its May 2023 letter to the Commission on the related matter of P-18 forms. The Commission should require that waste haulers make this information available for the public as well.

11. DIVISION 11 REQUIREMENTS FOR SURFACE WATER PROTECTION

§4.196. Surface Water Pollution Prevention. Page 81

Commission Shift urges the Commission to clarify that ***all*** of its water-protection and anti-pollution rules (including 4.196(b)(6)-(7)) apply to activities on land (not just in offshore or in-land waters) that cause pollution of any state waters, whether inland, fresh, offshore, estuarine or otherwise. It could do so more clearly by moving (d) to follow (a):

> (a) An operator shall not pollute the waters of the Texas offshore and adjacent estuarine zones (saltwater bearing bays, inlets, and estuaries) or damage the aquatic life therein.
>
> (b~~d~~) The requirements of this section shall also apply to all oil, gas, or geothermal resource operations conducted on land or on the inland and fresh waters of the State of Texas, such as lakes, rivers, and streams.

Commission Shift supports the Commission's proposed revision that would no longer allow any cutting and fluids from mud systems to be disposed of in Texas offshore and adjacent estuarine zones.[203] Furthermore, Commission Shift understands (e)(2)(A) was removed as the Commission no longer has jurisdiction over such discharges. (If that is not the case, then Commission Shift opposes removing regulations protecting waters from discharges.) Commission Shift requests confirmation

[202] "The RRC should adopt rules requiring the operator of a disposal facility to report waste management discrepancies." Ex. 6 STRONGER Texas Review, 2003 at 31 (citing 2000 Guidelines 5.10.2.3 d).

[203] Compare 3.8(e)(2)(E) ("Drilling muds which contain oil shall be transported to shore or a designated area for disposal. Only oil-free cutting and fluids from mud systems may be disposed of into Texas offshore and adjacent estuarine zones at or near the surface.") with § 4.196.

that the Commission's deletions in 3.8(e)(2)(D)[204] regarding the disposal of burned waste and edible waste into the ocean is an actual prohibition of this activity.

§4.197. Consistency with the Texas Coastal Management Program. Page 82

This section appears largely unchanged from the original rule and the May draft, except regulations regarding discharges have been removed (specifically 3.8(j)(1)(B) and 3.8(j)(3)(B)). The summary to the informal draft did not provide a rationale for this change, but Commission Shift believes this may be in recognition of the fact that many discharge permits previously issued by the RRC now fall under the TCEQ's jurisdiction. However, some discharges remain under the RRC's jurisdiction, and Clean Water Act Section 401 certifications continue to require the Commission to consider the effects of discharges from oil and gas activities. Commission Shift requests a rationale for why these sections were omitted from this draft. Whatever the reason, in making this amendment (and this rulemaking in general), the Commission must explain how this proposed rule amendment is consistent with the Coastal Management Plan, as required by 31 TAC 29.11(c).

Commission Shift notes that the language about large discharges into tidal waters found in the current rule at 3.8(j)(3)(B) and what would have been 4.197(c)(2) for "thresholds for referral" for a coastal consistency determination[205] has been removed in this draft. Commission Shift requests a rationale for why the following discharges will no longer be referrable to the General Land Office for review to determine consistency with the Coastal Management Plan:

> for discharges, any permit to discharge oil and gas waste consisting, in whole or in part, of produced waters into tidally influenced waters at a rate equal to or greater than 100,000 gallons per day.

By removing this language, such discharges will no longer be deemed to exceed thresholds for referral; in other words—as Commission Shift understands it—the General Land Office will not be able to review the Commission's determination on whether a permit is consistent with the state's coastal management plan, which is the federally-approved plan intended to "ensure the long-term environmental and economic health of the Texas coast."[206] Again, the Commission must explain how this proposed rule amendment is consistent with the CMP.

The Commission should also take the opportunity to strengthen the water-protection rules in this section. As drafted, section 4.197(a)(1)(A) would allow non-commercial oil and gas waste disposal pits, temporary pits, waste separation facilities, landfarms, and recycling facilities to be built inside

[204] This section stated: "Solid combustible waste may be burned and the ashes may be disposed of into Texas offshore and adjacent estuarine zones. Solid wastes such as cans, bottles, or any form of trash must be transported to shore in appropriate containers. Edible garbage, which may be consumed by aquatic life without harm, may be disposed of into Texas offshore and adjacent estuarine zones."

[205] (c) begins by stating "Any Commission action that is not identified in this subsection shall be deemed not to exceed thresholds for referral for purposes of the [Coastal Management Plan] CMP rules."

[206] https://www.glo.texas.gov/coast/grant-projects/cmp/index.html

the coastal zone.[207] The only prohibitions are for "commercial" oil and gas "disposal pits"—i.e.: "pit[s] used for the ***permanent interment*** of oil and gas waste"[208] that are located in:[209]

> A facility permitted under this chapter, whose operator receives compensation from third parties for the management of oil and gas wastes, whose primary business purpose is to provide such services for compensation***, and receives oil and gas wastes by truck***. In this paragraph, a third party ***does not include an entity that wholly owns the operator of the facility permitted under this chapter***

(for Commission Shift's arguments why "commercial" is too narrowly defined, see 4.110 above).

This leaves a lot of room for waste to be managed within the coastal zone. Nearby states like Louisiana have been prohibiting production pits from being constructed in the coastal zone since June 1989.[210] While the Commission must perform a "consistency review" of any permit that's requested in the coastal zone, as the rule is currently drafted it appears that only pits larger than 5 acres are subject to review of the commission's decision as to whether they are consistent with the state's plan for coastal management and protection. As the severity and frequency of severe storms increase, our coastal communities and the facilities built among them become more vulnerable. Open waste pits and waste operations, whether temporary or not, and whether commercial or not, are sources of compounding risk that our communities should be protected from with forward-thinking regulations.

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[207] 4.197(a)(1)(A) is as follows:
(a) Applicability. The provisions of this section apply only to activities that occur in the coastal zone and that are subject to the CMP rules.

> (1) Disposal of oil and gas waste in pits. The following provisions apply to oil and gas waste disposal pits located in the coastal zone.
>
> > (A) No commercial oil and gas waste disposal pit constructed after October 25, 1995, shall be located in any CNRA.
> >
> > (B) All oil and gas waste disposal pits shall be designed to prevent releases of pollutants that adversely affect coastal waters or critical areas.

[208] 4.110(31) (defining disposal pit).
[209] 4.110(21) (defining commercial facility).
[210] LAC 303.K.1. Except for exempt pits, no production pit may be constructed in the coastal area after June 30, 1989.

SUBCHAPTER B COMMERCIAL RECYCLING

Many of the same concerns Commission Shift expressed in comments on Subchapter A are relevant to the proposed rulemaking in Subchapter B; these general topics are summarized here before specific section-by-section feedback that focuses on Divisions 1, 5, 6, and 7.

Concerns related to Subchapter A comments:

The same concerns Commission Shift expressed in Subchapter A about the lack of meaningful public participation allowed for in the permitting process also apply to Subchapter B (including in § 4.207), and thus Commission Shift respectfully refers the Commission to its comments on Subchapter A on these topics.

The same concerns Commission Shift expressed in Subchapter A about the lack of meaningful public participation during permit renewals, amendments and transfers also apply to Subchapter B (including in §§ 4.209, 4.224, 4.261) and thus Commission Shift respectfully refers the Commission to its comments on Subchapter A on these topics (see § 4.122).

The same concerns Commission Shift expressed in Subchapter A about modifications, suspensions, and transfers also apply to Subchapter B (including in § 4.210), and thus Commission Shift respectfully refers the Commission to its comments on Subchapter A on these topics (see § 4.123).

The same concerns Commission Shift expressed in Subchapter A about penalties and the lack of meaningful enforcement also apply to Subchapter B (including in § 4.211), and thus Commission Shift respectfully refers the Commission to its comments on Subchapter A on these topics (see § 4.107).

The same concerns Commission Shift expressed in Subchapter A about: (1) the need for the Commission to have a mechanism to deny incomplete applications that do not meet the Commission's minimum standards (without allowing applicants to waste Commission resources in or a hearing or for the technical staff's decision to be overruled by Commissioners); and (2) the need for a mechanism to prevent applicants from continuing to modify their applications even during the hearing stage; also apply to Subchapter B (including in §§ 4.212, 4.230), and thus Commission Shift respectfully refers the Commission to its comments on Subchapter A on these topics.

The same concerns Commission Shift expressed in Subchapter A about the need for: (1) a community relations/public information plan; (2) site-specific inspection forms; and (3) a review of prior applications and permits; also applies to Subchapter B (including in §§ 4.214, 4.234, 4.250, 4.251, 4.266), and thus Commission Shift respectfully refers the Commission to its comments on Subchapter A on these topics (§§ 4.124, 4.128, 4.142).

The same concerns Commission Shift expressed in Subchapter A about the need for appropriate setbacks and location considerations also apply to Subchapter B (including §§ 4.219, 4.240, 4.256, 4.264, 4.278, 4.280), and thus Commission Shift respectfully refers the Commission to its comments on Subchapter A on these topics (§ 4.150).

The same concerns Commission Shift expressed in Subchapter A about the length of the notice period, who gets notice and how also apply to Subchapter B (including §§ 4.238, 4.254, 4.270, 4.272, 4.286), and thus Commission Shift respectfully refers the Commission to its comments on Subchapter A on these topics.

The same concerns Commission Shift expressed in Subchapter A about monitoring for leakage and leakage rates also apply to Subchapter B (including §§ 4.275, 4.291), and thus Commission Shift respectfully refers the Commission to its comments on Subchapter A on these topics.

1. DIVISION 1. GENERAL; DEFINITIONS

§4.202. Applicability and Exclusions. Page 1

Commission Shift objects to the grandfathering of permits issued prior to the current rulemaking (section h). The Commission should set a deadline by which all operations permitted under the previous rules must come into compliance. To ensure that human and environmental health is protected, Commission should retain the power to make changes to these permits even before the deadline is reached.

§4.204. Definitions. Page 2

Commission Shift recognizes that some changes are required by statute, like the definition of "drill cuttings." Others are left to the Commission's discretion, like the definition of "legitimate commercial product."[211] The proposal defines this as "[a] product of a type customarily sold to the general public for a specific use and for which there is a demonstrated commercial market." 4.204(8). But this appears to be simply the definition of a commercial product[212]—not necessarily a ***legitimate*** one.

The Commission has been given the opportunity to define the full term "legitimate commercial product"—it should use this opportunity to incorporate the fact that a legitimate commercial product is also one that does not risk harming human health and public safety or environmental receptors, that has been fully tested, and that has long-term viability.

[211] Tex. Nat. Res. Code § 123.0015(b).
[212] With plenty of vague language ripe for exploitation to allow for products that do not have any long-term viability and have not been fully tested.

Incorporating the concept of how a commercial product must (at a minimum) not be harmful to be considered “legitimate” makes sense because the term “legitimate commercial product” is used to define when use of drill cuttings is “beneficial.” Tex. Nat. Res. Code § 123.0015(a) states:

> (a) For the purposes of this chapter, **a use of drill cuttings is considered to be beneficial** if the cuttings are used:
>
> (1) in the construction of oil and gas lease pads or oil and gas lease roads; or
>
> (2) **as part of a legitimate commercial product**.

The Commission should thus revise the definition of “legitimate commercial product” to reflect the fact that this term must also be able to describe when a use of drill cuttings is actually “beneficial.”

§4.205. Exceptions. Page 5

Commission Shift is concerned by the language in this section on exceptions, and in particular the language in (c)(1). It appears that the Commission is intending to incorporate legislation codified in Texas Natural Resources Code § 122.004(f), which states that “An application requesting a variance from the standards adopted under this section must be evaluated and determined to be substantially similar to previous variances approved by the commission.”

On its face, this language states that one element of the Commission’s review is to determine whether the exception is “substantially similar” to previous exceptions. While this may be a ***necessary*** finding, it is not ***sufficient*** to warrant granting the application—and the statutory language reflects this. Over and over again the Legislature has directed the Commission to always consider a ***second*** element—that the proposed operation is protective of public health and safety and the environment.[213] In other words, applicants must prove both elements ***separately***. Simply because a requested variance is “substantially similar” to a previously-granted variance does not make it safe. The Commission should rewrite section (c)(1) to clarify that showing that an exception is “substantially similar” to one granted previously is ***not*** the same as showing that it is also sufficiently protective of health and the environment. Intervening events or data may show that the previously granted exception is no longer protective of health and the environment. Applicants should be required to affirmatively prove an exception is protective, and not simply rely on an asserting that is “substantially similar” to one granted in the past.

The same concerns Commission Shift expressed about the exceptions provided for in Subchapter A § 4.109 also apply to Subchapter B, and thus Commission Shift respectfully refers the Commission to its comments on Subchapter A on this topic.

[213] For example, in the context of drill cutting reuse, Tex. Nat. Res. § 123.005 (b) states that “A rule adopted by the commission under this chapter or a permit or order issued by the commission regarding the treatment and beneficial use of drill cuttings must be at least as protective of public health, public safety, and the environment as a rule, permit, or order, respectively, adopted or issued by the commission regarding the disposal of drill cuttings.”

2. DIVISION 3. REQUIREMENTS FOR OFF-LEASE OR CENTRALIZED COMMERCIAL SOLID OIL AND 21 GAS WASTE RECYCLING.

§4.232 Minimum Siting Information. Page 15

Commission Shift notes that the siting information required to be in an application for off-lease or centralized commercial solid oil and gas waste recycling is much less detailed than the information required for operations in Subchapter A. In addition, more discretion is left to the operator to choose a source of this information (e.g., the source of flood plain information and characterization of subsurface water). The Commission could incorporate by reference Subchapter A's methods for acceptable means to gather this information (much of which is in § 4.114 and § 4.131), or repeat the information here—in any event it is relevant to both disposal and recycling operations.

These deficiencies are repeated in Division 4 and 5's (§4.248 and §4.264, respectively) requirements for stationary commercial solid oil and gas waste recycling facilities, and should be remedied there as well.

§4.241 Minimum Permit Provisions for Design and Construction. Page 19

For sections 4.241, 4.257, Commission Shift has similar concerns as those expressed in § 4.232 about how data is collected for the installation of monitoring wells and the assessment of whether groundwater is present. Subchapter A's provisions on soil investigations and monitoring well installation should be referenced or incorporated. In addition, the list of parameters that groundwater wells must be sampled for in § 4.259 should include at least toluene, ethylbenzene, and xylene (a complete BTEX suite for the same reasons as discussed in Commission Shift's comments on Subchapter A) metals, and pH. Commission Shift also questions why this list of sampling parameters does not apply to all operations under Subchapter B.

3. DIVISION 5. REQUIREMENTS FOR OFF-LEASE COMMERCIAL RECYCLING OF FLUID.

§4.263 Minimum Engineering and Geologic Information. Page 34

In this section and related ones about the minimum engineering and geologic information that is necessary, Commission Shift notes that the information required to investigate the subsurface geology is much less detailed than the information required for operations in Subchapter A. In addition, more discretion is left to the operator to choose a source of this information—e.g., subsection (b) allows site characterization information to come from "available information"—not necessarily site-specific investigations. For all the reasons Commission Shift explained in Subchapter A, the only way to fully characterize the subsurface and identify subsurface water (which the Commission has a duty to protect) is with site-specific investigations. Subsection (b) should be revised to require this information before an application can be approved. Likewise, subsection (c) provides very little detail on how "background" is to be determined, in contrast to the detail in Subchapter A. Commission Shift raises the same concerns with respect to § 4.279, which is a similar section.

§4.266 Minimum Design and Construction Information. Page 35

The level of detail on pit construction that the Commission has proposed in § 4.266 (and § 4.282) in many ways exceeds the level of detail provided for in Subchapter A. Many of Commission Shift's recommendations appear to have been incorporated into this section—for example the requirements that quality assurance / quality control testing reports be obtained[214]; that liners should be anchored into compacted earth; that very specific details have been given on the liner type, thickness, and leak detection system construction. Commission Shift reiterates however the freeboard in the pit should be able to handle the 25-year, 24-hour rain event ***plus*** two feet of vertical distance (subsection (a)(12)).

§4.272 Minimum Permit Provisions for Siting. Page 43

Commission Shift strongly objects to the new last sentence that has been added to § 4.272(a) and § 4.288(a) as follows:

> §4.272(a) A permit for off-lease commercial recycling of fluid may be issued only if the <u>Director</u> [~~director~~] or the Commission determines that the facility is to be located in an area where there is no unreasonable risk of pollution or threat to public health or safety. <u>The Director will presume that an application meeting the requirements of §4.264(a) of this title (relating to Minimum Siting Information) does not present an unreasonable risk of pollution or threat to public health or safety with regard to siting, unless extraordinary circumstances indicate otherwise.</u>[215]

Asking the Commission to disregard a risk of pollution "unless ***extraordinary*** circumstances" are shown is a dangerously high bar to put between the Commission and its duty to protect public health and safety and the environment. It will be virtually impossible for the public to surmount. It will force the Commission to disregard information that indicates that a site creates a risk of pollution or threat to public health or safety—only "extraordinary" information or circumstances would suffice. This standard is a risk to human and environmental health all its own.

Commission Shift sees no statutory mandate for this language to be included—the notice of informal comment disclosed House Bill 3516 as the ***only*** legislative driver for the changes to Divisions 5 and 6—and H.B. 3516 has no such language in it.[216] Commission Shift has been unable to find this language in any other law or statute. The last sentence of (a) should be omitted.

[214] Though these should also be reported to the Commission.
[215] The problematic last sentence of § 4.288(a) is identical to that of § 4.272(a).
[216] Ex. 44 (Enrolled version of H.B. 3516, 87th Legislature, Regular Session).

7. DIVISION 7. BENEFICIAL USE OF DRILL CUTTINGS.

§4.301. Activities Related to the Treatment and Recycling for Beneficial Use of Drill Cuttings. Page 67

This Division envisions allowing drill cuttings to be spread across all county roads, all oil and gas lease roads, and to be included in construction aggregate, fill material and concrete (and more). The potential for widespread pollution and harm to human health and public safety warrants much more detailed regulations and much more scrutiny than it has received, tucked in as last pages in a massive rewrite of Chapter 4. The minimal guidelines in this Division puts Texans at risk—the Commission needs to go back to the drawing board when it comes to regulating the use of drill cuttings and bring the public to the stakeholder table alongside industry immediately.

Commission Shift recognizes that the Legislature has directed the Commission to draft rules for the use of drill cuttings (i.e., this new Division), but it has been given significant leeway in the rules that can be set. The Commission appears to only be limited by the constraints that:[217]

> A rule . . . regarding the treatment and beneficial use of drill cuttings ***must be at least as protective*** of public health, public safety, and the environment as a rule . . . adopted . . . by the commission ***regarding the disposal of drill cuttings***.

and[218]

> The commission by rule shall adopt criteria for beneficial uses to ensure that a beneficial use of recycled drill cuttings under this chapter is ***at least as protective*** of public health, public safety, and the environment ***as the use of an equivalent product made without recycled drill cuttings***.

The Commission must thus take into consideration the protections provided when disposing of drill cuttings and the impacts of equivalent products made ***without*** drill cuttings. The Commission is free to enact standards that are more protective—which it must do. Drill cuttings as defined are not simply geologic material removed from the wellbore, but may include residual additives used in drilling muds (oil-based, water-based, and synthetic-based) cleaned out of the wellbore, including potentially hazardous materials. [219] These rules do not define how much, if any, pretreatment of drill cuttings must be done before the material is an appropriate ingredient—and whether that pre-treatment would be done by the generator at the wellpad or at the facility conducting Division 7 operations. The rule assumes all drill cuttings are fungible rather than acknowledging the expected

[217] Tex. Nat. Res. Code § 123.005(b).
[218] Tex. Nat. Res. Code § 123.0015 (c).
[219] "Drill cuttings" is defined by statute to mean: "bits of rock or soil cut from a subsurface formation by a drill bit during the process of drilling an oil or gas well and lifted to the surface by means of the circulation of drilling mud. The term includes any associated sand, silt, drilling fluid, spent completion fluid, workover fluid, debris, water, brine, oil scum, paraffin, or other material cleaned out of the wellbore." Tex. Nat. Res. Code § 123.001(1).
"Treatment" means "a manufacturing, mechanical, thermal, or chemical process other than sizing, shaping, diluting, or sorting." Tex. Nat. Res. Code § 123.001(4).

wide variation in characteristics of each incoming load of drill cuttings depending on type of well, mud additives, and other considerations.

As Subchapter A proposes, drill cuttings that are disposed of are typically placed in consolidated privately owned locations, becoming at most point source reservoirs of pollution—they are buried in a landfill or potentially landfarmed in a contained, monitored space. However, this Division envisions the use of cuttings publicly—along oil and gas lease roads (a use named in the statute) ***and*** along county roads—which is not a use that the statute requires the Commission to regulate or allow. There are over 300,000 lane-miles of certified county roads in Texas, according to The County Information Program,[220] or 47% of all roads in the state, according to TxDOT and 2017 data from the Federal Highway Administration.[221] Division 7 creates the framework for all of these roads to become sources of pollution and human health and public safety risks if strict enough environmental protections and oversight are not set.

Section (b) also envisions the use of drill cuttings ""as a concrete bulking agent, oil and gas waste disposal pit cover or capping material, treated aggregate, closure or backfill material, berm material, or construction fill." Several of these categories of products could be used all over the state—like concrete bulking agent, treated aggregate, and construction fill.

Commission Shift strongly objects to rules being drafted to allow uses that are not envisioned in the statute. The Commission should disclose which entities or individuals are requesting to allow drill cuttings on county roads and "as a concrete bulking agent, oil and gas waste disposal pit cover or capping material, treated aggregate, closure or backfill material, berm material, or construction fill."

Thus at a minimum, section (b) should be modified as follows to restrict the applicable beneficial reuse to oil and gas roads that are not also public county roads and restructured so that requirements (3)(A) and (3)(B) must be demonstrated for all uses.

> (b) The Commission may approve a permit for the treatment and recycling for beneficial use of drill cuttings if:
>
> (1) the applicant can demonstrate that the product:
>
> > (A) meets the engineering and environmental standards for the proposed use; and
> >
> > (B) is at least as protective of public health, public safety, and the environment as the use of an equivalent product made without treated drill cuttings;
>
> (2) and the treated drill cuttings are used:

[220] Ex. 45 Texas Counties: Lane Miles, Certified County Roads (Data source: Texas Department of Transportation. Annual Roadway Inventory Reports. (2022)) https://txcip.org/tac/census/morecountyinfo.php?MORE=1079 Lane-miles are determined by multiplying centerline miles by the road's number of lanes so better capture the area of the roadway as compared to centerline miles, which are the total length of a road or road segment.

[221] Ex. 46 The State of Highways in Texas. At 3 https://ftp.txdot.gov/pub/txdot-info/tpp/2050/meeting-materials/round-02/highway-intro.pdf

> (A) in a legitimate commercial product for the construction of oil and gas lease pads or oil and gas lease roads that are not also county roads;
>
> ~~(B) in a legitimate commercial product for the construction of county roads; or~~
>
> ~~(C) in a legitimate commercial product used as a concrete bulking agent, oil and gas waste disposal pit cover or capping material, treated aggregate, closure or backfill material, berm material, or construction fill.~~

§4.302. Additional Permit Requirements for Activities Related to the Treatment and Recycling for Beneficial Use of Drill Cuttings. Page 67

Section (a) gives two examples of how an applicant could show that there is a demonstrated commercial market for treated drill cuttings:

> (a) An applicant for a permit to treat and recycle drill cuttings for beneficial use shall show that there is a demonstrated commercial market for the treated drill cuttings. The applicant may make this showing by providing:
>
> (1) evidence that the same product made with drill cuttings or a product that is substantially similar is commonly used in the area where the product is created
>
> (2) evidence of actual commitments from customers who intend to use the product made with drill cuttings, including information regarding the volume of product the customers intend to use annually; or
>
> (3) other credible and verifiable means consistent with the rules in this chapter.

As an initial matter, Commission Shift notes that the Commission has substituted the word "demonstrated" for "legitimate" as what must be shown for a commercial product to be legitimate. "Demonstrated" is not necessarily a synonym for "legitimate," as Commission Shift explained in its comments on § 4.204. In addition "evidence" is not defined—as written it could simply be an email chain—which the applicant could argue is sufficient to show a permit is merited.

As for subsection (a)(1), "evidence that the same product made with drill cuttings ***or a product that is substantially similar*** is commonly used ***in the area where the product is created*** " is not relevant to whether there is a commercial market for drill cuttings in the location **where they are to be used.** This doesn't even require that the area producing the product is using drill cuttings at all—it just has to be a "substantially similar product," which is undefined, and "commonly" used, which is also undefined. Under this definition, evidence that roadbed material is being made and used in a location halfway around the world might suffice (it should not). Subsection (a)(1) doesn't even require "commercial use"—it could be still in a research phase, donated, or even dumped. Worse, section (a)(3) would expand the scope of (a)(1) as it would allow evidence that is "consistent with the rules in this chapter" . . . which includes (a)(1).

In short, section (a)(1) should be removed in its entirety.

In addition, (a) references the need for a permit to treat drill cuttings, but then gives no explanation for how that permit would be obtained, the public's ability to participate, and what it would involve. This fundamental flaw reinforces the fact that this Division should not move to formal comment—it's not ready.

It appears that large portions of this Division are simply cut and paste from others in Subchapter B without careful consideration whether those borrowed rules apply to and are sufficient for Division 7. As for section (b), Commission Shift is very concerned that only a single "trial run" would be required to demonstrate the suitability of a drill cuttings-based product. Drill cuttings have been defined to be a product that contains "any wellbore material"—many experiments should be run using a variety of sources of drill cuttings feedstock in order to capture influence from a wider range of potential contaminants. A single trial run is also insufficient given the widespread intended application of this product—scattered on roads and in aggregate across the state—and thus this section should be altered accordingly. Requiring on-going sampling of the product (as contemplated in (c)(1)(B)) during its production is not the same thing as ensuring that the production process consistently produces material that will not put public health, safety, and the environment at risk.

This section also references ASTM standards that are behind paywalls. As Commission Shift has pointed out in comments on previous sections, the public will not be able to provide meaningful feedback unless the Commission provides summaries of these standards, including what these standards are suitable for (and not suitable for).

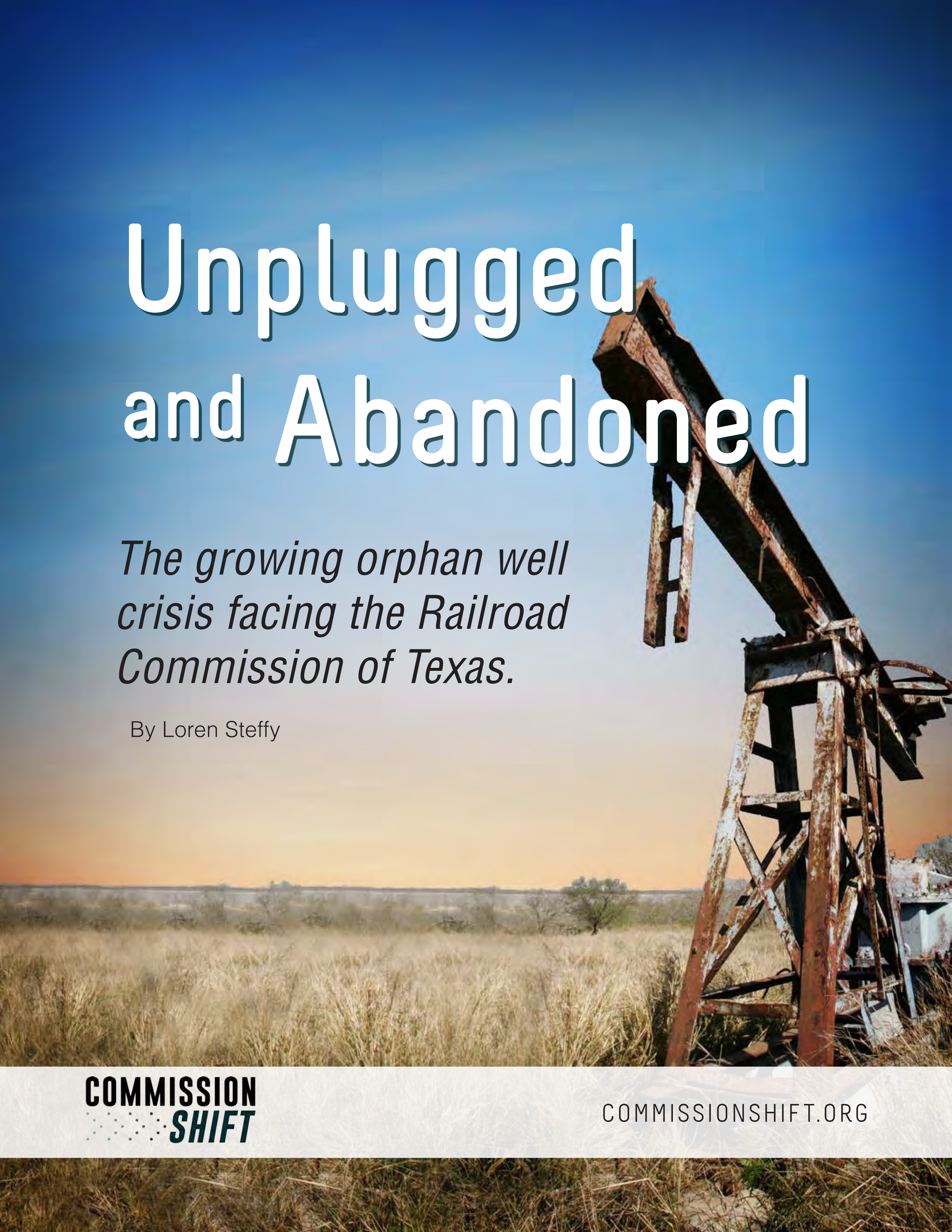
As for subsection (c), it only requires the reporting of lab analyses and a "letter of authority" application for materials that are in category § 4.130(b)(3). These requirements (c)(2)(D) and (c)(2)(E) must also be requirements for use of drill cuttings on roads (i.e., added as (b)(2)(D) and (b)(2)(E)). There is no legitimate reason for the distinction. As written, the rule only requires the reporting of lab tests and submittal of an application for a permit without an obvious public notice and participation component. The rule does not include a clear path for the Commission and the public to monitor the efficacy of the program through its operational lifespan. And then the Commission must add more detail to explain how a letter of authority would work (e.g., is it a single letter that suffices for all uses?). The "letter of authority" process should include the opportunity for the public near the site where this material is to be used to weigh in on the application, akin to the notice and protest provisions elsewhere in these rules.

As for the sampling required, the list of metals and organics does not seem to encompass all potential pollutants in drill cuttings and any 'treatment' additives used in the permitted process. The Division 7 Rule appears to be rushed and poorly conceived, especially given the lack of detail on the reuse process. The resulting 'beneficial use' material could conceivably be used in numerous public applications where the public would be unknowingly exposed, potentially every day.

The lesson learned throughout the history of Rule 8 is that vague and incomplete regulations are difficult to implement and enforce. Rather than learning from past mistakes, Division 7 will repeat that history. Commission Shift strenuously requests that the Commission not include Division 7 in the upcoming formal rulemaking process.

Exhibit 16.02

This exhibit was not previously submitted in November 2023



Unplugged and Abandoned

The growing orphan well crisis facing the Railroad Commission of Texas.

By Loren Steffy

COMMISSION SHIFT

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Commission Shift thanks and acknowledges the research contributions of Emma Pabst at Environment Texas, staff at Documented, and Virginia Palacios at Commission Shift in preparing this report.

Commission Shift is building public support to hold the Railroad Commission of Texas accountable to its mission in a shifting energy landscape.

Contrary to what its name implies, the Railroad Commission of Texas has no authority over railroads. Instead, the agency oversees oil and gas development, coal and uranium mining, and gas utility service in Texas, among other functions. Its mission is to serve Texas through stewardship of natural resources and the environment, concern for personal and community safety, and support of enhanced development and economic vitality for the benefit of Texans. Too often, the Commission has promoted enhanced development of oil and gas over all other parts of its mission -to the detriment of natural resources and the environment, safety, and economic vitality.

Commission Shift is educating and organizing a wide array of stakeholders to build support for changes at the Railroad Commission of Texas (RRC) that improve the agency's function, transparency, and accountability to people and places impacted by the oil and gas industry.

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Reforming oil and gas oversight in Texas

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Executive Summary

As investment moves away from oil and gas companies in favor of businesses with a better return, the state of Texas faces a significant economic threat. Combined with declining demand from depressed commodity prices, shifting consumer preferences and the global COVID-19 pandemic, the state faces a surge in oil and gas company bankruptcies and declining revenue from fees it collects from the industry. Meanwhile, the Railroad Commission of Texas—the state's oil and gas regulator—has been asleep at the switch.

Insolvent or financially distressed operators exacerbate the potential economic risks, public health dangers and environmental hazards posed by unplugged and abandoned oil and natural gas wells. As the wellbore deteriorates, it can leach oil, gas, and residual drilling fluids into groundwater supplies. Unplugged and abandoned wells also can release methane, a powerful greenhouse gas, into the atmosphere and open pits for collecting wastewater or other byproducts of the drilling process can leak and pose threats to groundwater as well.

Texas could face a dramatic increase in the number of "orphan" wells—those abandoned by companies that are no longer solvent. While environmental liabilities typically can't be dismissed in bankruptcy, companies often find a way to shift their liabilities to other entities or simply mask them from regulators. As a result, the state faces the prospect of more abandoned wells and rising cleanup costs.

The Railroad Commission has had opportunities to confront the transition occurring in the energy business and better prepare for the declining revenue and rising environmental risks it poses. So far, however, it has failed to do so.

For years, Texas had a well-funded program to ensure that the state was protected from the cost of plugging wells and remediating contaminated well sites through fee revenue and a bonding program funded by operators.

But these programs aren't keeping pace with the increased rate of drilling and higher costs for plugging and remediation associated with hydraulic fracturing and horizontal drilling. While fracked wells cost more to drill, their sites also can have higher remediation costs because of large amounts of wastewater and chemicals left behind by the process. Longer, horizontal wells also cost more to plug.

The potential increase in orphan wells could leave the Commission facing an increase in cleanup costs at a time of state budgetary shortfalls and cutbacks. The well plugging and cleanup costs already exceed the balance of the state's remediation fund, and taxpayers are bearing some of the cost of these liabilities. Other states have adopted or are considering more innovative solutions for addressing the backlog of orphaned wells.

The Railroad Commission, however, waived plugging requirements and fees that go into the Commission's cleanup program just after the coronavirus pandemic began and oil prices crashed, essentially letting companies off the hook for their environmental liabilities at a time when the Commission and the state can least afford it. In doing so, the Commission has protected the industry it's supposed to regulate at the expense of taxpayers, landowners, and the environment.

I. Introduction

When Fort Worth-based Weatherly Oil & Gas LLC, which operated more than 800 oil and natural gas wells, filed for bankruptcy in February 2019, it blamed weak commodity prices and fundamental changes in lending practices.[1,2,3]

Weatherly had 163 “orphan” wells, more than any other operator in the state, according to records filed with the state’s oil and gas regulator, the Texas Railroad Commission.[4] The state defines orphan wells as those that have been inactive for 12 months or more and that are out of compliance with regulatory requirements such as filing regular organization reports.[5] (By contrast, “abandoned” is a broader term that means a well is no longer active. Abandoned wells may have ceased production and been properly plugged by the operator, or they may be orphaned. The two terms are often used interchangeably, adding to the confusion about the hazards posed by orphaned and abandoned wells.)

In some cases, the operators of orphan wells either can no longer be found or can no longer afford to pay for plugging and remediation of a well site. When this happens, the state winds up picking up the tab eventually, but a backlog of orphaned wells means that it could take years for the Railroad Commission to plug newly orphaned wells. In the meantime, the unplugged wells pose an environmental risk.

Like many companies using hydraulic fracturing, or “fracking,” to extract oil and natural gas from shale formation thousands of feet below the earth’s surface, Weatherly borrowed heavily against its cash flow to finance new drilling. The more it drilled, and the more oil and gas it produced, the more its cash flow increased, allowing it to borrow more and repeat the process.

With historically low interest rates, lenders and investors happily poured money into the Texas oil patch, believing that the increased drilling would pay off. By 2019, however, they began to sour on the cash-flow model. Investors wanted a return, and lenders wanted more tangible collateral, specifically reserves and profits.

As its financing dried up, Weatherly found itself without enough capital to maintain its drilling program, and it diverted more cash flow toward paying senior debt holders.[6]

Across the country, hundreds of other companies have faced similar cash crunches. Since 2015, more than 250 producers in North America have filed for bankruptcy, representing more than $175 billion in debt. Almost half of those—124—were in Texas, which leads the nation in oil company bankruptcies. Forty-five producers filed for bankruptcy in 2020, a 61 percent increase from two years earlier.[7]

Weatherly’s abandoned wells hint at a much larger problem. In Fiscal Year 2020, the Railroad Commission classified about 6,200 wells as orphaned, and it plugged fewer than 1,500 of them. More than 146,000 additional wells are listed as “inactive.”[8]

Under the Commission’s rules, a well must generate at least five barrels a month for three consecutive months, or at least one barrel a month for 12 consecutive months to be considered producing or “active.” For gas wells, it’s 50,000 cubic feet a month for three consecutive months or at least 1,000 cubic feet for 12 consecutive months.[9]

If a well falls below these production levels, it's considered inactive, and the operator must disconnect electricity from the well equipment.[10]

After a certain period of time, an operator may decide to plug and abandon a well, meaning they permanently shut it down and fill the wellbore with cement. After a well has been shut in for 10 years, operators must remove the wellhead and other surface equipment.

However, the complexity of the rules, lax monitoring by the Commission, lenient enforcement and nominal fines undermine the Commission's responsibility to hold operators accountable.[11] Inactive and abandoned wells can become orphaned if the operator goes out of business or transfers the liability for the well to other entities who can't cover the remediation costs.

Abandoned, inactive and orphaned wells can contaminate groundwater and leak poisonous gases or methane, which contributes to the greenhouse effect and accelerates climate change. Some can even explode. What's more, unplugged and abandoned wells nationwide emit roughly the same amount of carbon as 2.1 million passenger cars.[12]

The state's laws requiring operators to pay for plugging inactive or abandoned wells are so weak that if companies like Weatherly go bankrupt or simply walk away from problem wells, the cleanup responsibility often shifts to the state.

To help offset these potential costs, the Railroad Commission collects fees and surcharges from operators when they begin drilling, and it requires that some operators post surety bonds to cover the cleanup costs for orphan wells and the surrounding sites. Unfortunately, the bonds cover cleanup costs for less than 3 percent of all unplugged wells.[13]

In 2009, Texas lawmakers recognized that the bonding program was falling behind. They passed a bill requiring operators to remove all surface equipment from wells that had not produced in 10 years. The Commission, which adopted the measure as RRC Statewide Rule 15 a year later, wanted to ensure that long-inactive wells were either plugged or brought back into production.[14]

Even so, the new requirements only covered a small percentage of the Commission's plugging expenses, which continued to grow as drilling activity accelerated during the fracking boom which continued until 2019.[15]

By May 2020, with bankruptcies rising, the Railroad Commission suspended requirements that operators plug wells and remediate pits within a year of ceasing operations.[16] The Commission also waived filing fees and surcharges that are deposited to the Oil and Gas Regulation and Cleanup (OGRC) Fund, which ordinarily covers most orphan well cleanup. As a result of the Commission's inaction, Texas' growing abandoned and orphaned well problem could pose a significant long-term risk to Texas taxpayers and the environment.

II. The Railroad Commission Must Recognize Systemic Decline and Use its Tools to Prevent Bankruptcies

In the spring of 2020, U.S. oil and gas producers found themselves facing an existential threat. Investors had soured on the industry, after years of pumping in capital. The industry was the worst-performing sector of the Standard & Poor's 500 Index over the past decade, with returns falling almost 40 percent in 2020 alone.[17]

For years, the industry spent more than it made on fracking as it expanded production and reduced the country's four-decade dependence on foreign oil. Fracking, in its modern form, was developed by Houston-based Mitchell Energy and Development Corp., which owned a large number of leases that had produced natural gas in Denton and Wise counties northwest of Fort Worth since the 1950s.

As those fields played out, Mitchell began looking for ways to replace its dwindling reserves. Geologists had known that natural gas forms in dense shale rock thousands of feet below the surface, then migrates to more porous rock formations such as limestone. There it pools into reservoirs that, when punctured by a drill bit, could be extracted.

After 17 years of trial and error, Mitchell in the late 1990s developed a method using water, sand and chemicals injected at high pressure into "unconventional" shale formations, creating tiny fractures that release the natural gas.

Fracking costs more than conventional drilling, but as natural gas prices rose in the early 2000s, Mitchell was able to make money. Other companies took notice, and they combined fracking with horizontal drilling, in which the well is drilled vertically into the shale, then angled horizontally across the formation. The technique allowed for more fractures, and thus more production, from each well. The proliferation of fracking opened up new areas of Pennsylvania, North Dakota and other states to new drilling, and revitalized established oilfields such as the Permian Basin of West Texas, unleashing unprecedented reserves of natural gas and later oil.[18]

By 2016, the United States had become one of the world's largest energy producers for the first time since the 1970s, breaking the grip of OPEC, and in 2019, it actually exported more oil than it imported for the first time since 1973.[19]

All of this success touched off a feeding frenzy as companies rushed to tap into new shale reserves. The oil industry has always operated on boom-and-bust cycles, but this time the boom was fueled not just by demand but by low interest rates.

As the Federal Reserve kept interest rates near zero to stimulate the economy after the Great Recession of 2008 and 2009, private equity funds and institutional investors, desperate for higher returns, poured money into shale producers.

In addition to costing more than conventional wells, production from fracked wells also declines more quickly. As a result, producers must drill more wells, which in turn, increases the industry's need for capital.[20]

That increased drilling activity from the fracking boom has heightened risks to public health. Between 2000 and 2013 alone, more than 15.3 million Americans had an oil or gas well drilled within a mile of their home, and the numbers have only increased since then.[21] As the production in those wells decline, and the operators abandon them, the risk to nearby homeowners increases.

There are other risks, too. As far back as 2002, then-Railroad Commissioner Tony Garza noted that abandoned wells "may very well pose a potential threat to Texas' most precious natural resource—water."[22] While leaking wells sometimes cause surface pollution, such as when oil or brackish water ooze to the surface, many times the threat remains well below the surface, where oil, toxic minerals or other substances left over from the drilling process migrate into aquifers or water supplies.[23]

The proliferation of wells since the fracking boom can pose long-term risks that are greater than the risks from conventional drilling, including threats to water supplies and air quality, wastewater disposal issues and heightened instances of earthquakes.[24] The Texas Groundwater Protection Committee, a group of 10 state agencies that coordinate groundwater regulation, identified 568 cases of groundwater contamination in 116 counties from oil and gas activity, 27 of which were added to the list in 2019. (All of the cases on the list are still in the enforcement process. Cases that were resolved in prior years are not included on the list.)[25]

As drilling and production rose, prices fell, leading to a bust in 2014 and another one two years later. With each price decline, operators scaled back production until prices rose again. But by mid-2019, investors began to tire of the financial treadmill. The companies they had invested in were producing lots of oil and gas but not much profit. Their drilling programs were costing more than they were earning. By May 2019, nine in 10 shale companies were overspending their cash flow.[26]

Investment began to dry up, and producers worried about covering their debts and generating enough return to satisfy investors.

Then, in early 2020, a standoff over production quotas between Saudi Arabia and Russia sent oil prices into a tailspin just as COVID-19 lockdowns in the United States and Europe cut into oil demand. The price for West Texas Intermediate crude tumbled more than 60 percent, slipping below $20 a barrel. At the end of April, WTI futures actually turned negative for the first time in history—meaning investors had so much oil they would theoretically pay someone to take it away. The "negative oil" didn't last long. Prices turned positive again the next day, but the message was clear: this was a bust unlike any the industry had ever seen.

a. Shifting preferences indicate permanent decline

While the combination of weak prices and weak demand are exacerbating the industry's financial problems, another factor is also contributing to its long-term decline: consumer preferences for alternatives to oil.

In its annual energy outlook, BP—one of the world's biggest oil companies—predicted demand could peak this decade at levels not much higher than they were before the pandemic. How quickly it declines depends on the speed with which governments enact policies to combat climate change. By 2050, oil use could fall by as much as 80 percent, the company estimated.[27]

Some of the biggest oil producers are embracing the change. Over the next five years, supermajors worldwide, including BP, have pledged to invest some $18 billion in clean energy, and while this is less than 10 percent of the industry's total capital outlays, it represents a significant increase from the 1 percent spent on green projects in 2018.[28]

Part of the reason for the shift: consumers are changing their habits. Electric vehicles, for example, will account for 60 percent to 80 percent of all new car sales, compared with just 2.2 percent in 2020.[29]

Investors are shifting their focus as well. Some of the world's biggest fund managers have vowed to liquidate their fossil fuel holdings, concentrate on financing renewables and other climate friendly energy sources, or both.[30]

Policymakers, concerned about climate change, are increasingly adopting regulations that favor cleaner energy sources, such as wind and solar power, over fossil fuels. Concerns about climate change have prompted the mayors of 12 major cities—representing 36 million people around the world—to call for the divestment of fossil fuels.[31]

While that may be good news for the climate over the long-term, it presents growing environmental risks as oil and gas producers sell off or abandon poorly performing oil and gas properties, leaving regulators stuck with the cleanup. One recent study found that the shift from fossil fuels to renewables could force the eight biggest oil companies—Exxon Mobil, BP, Shell, Total, ENI, Chevron, ConocoPhillips and Equinor—to sell $111 billion worth of assets in the coming years to compete in a low-carbon world.[32] By failing to recognize this shift and waiving fees and surcharges that help pay for plugging, the Railroad Commission could find itself with a growing number of orphan wells and less money for plugging them.

But who will buy those properties in a world that no longer wants them? To answer that question, it helps to look at what has happened in the coal industry. About half of all U.S. coal was mined by companies that have since gone bankrupt. As with oil and gas, bankruptcy laws are designed to give priority to environmental liabilities, but a recent study published in the Stanford Law Review in April 2019, found that coal companies had used the bankruptcy reorganization process to shed $5.2 billion worth of environmental liabilities by transferring them. Coal producers simply concentrated the liabilities in underfunded subsidiaries that they later spun off, and those companies later failed.[33]

b. Laissez-faire approach contributes to bankruptcies

Just after COVID-19 lockdowns caused U.S. oil demand to plummet in March 2020, frightened producers called on the Railroad Commission to enact production quotas, an authority the Commission hadn't exercised in five decades. The agency's mission is to safeguard Texas' natural resources and support "economic vitality" for the benefit of all Texans.[34]

From the early 1930s to the early 1970s, that support meant regulating production to ensure stable prices and prevent oversupply. But as bankruptcies swelled with the COVID-19 lockdowns, the Commission did little to protect producers from economic collapse.

Production quotas would have required producers in the state to cut their output by 20 percent until the market stabilized. More than 90 speakers, mostly from the industry, signed up for a hearing in mid-April.

"If the Texas Railroad Commission does not regulate long term, we will disappear as an industry," warned Scott Sheffield, chief executive officer of Pioneer Natural Resources, a major independent producer.[35]

The producers found a sympathetic ear in Ryan Sitton, one of the three Republican Commissioners. “We are seeing a level of demand destruction and oil industry downturn that in the past occurred over a period of years now happening over a period of days,” he warned in April.[36]

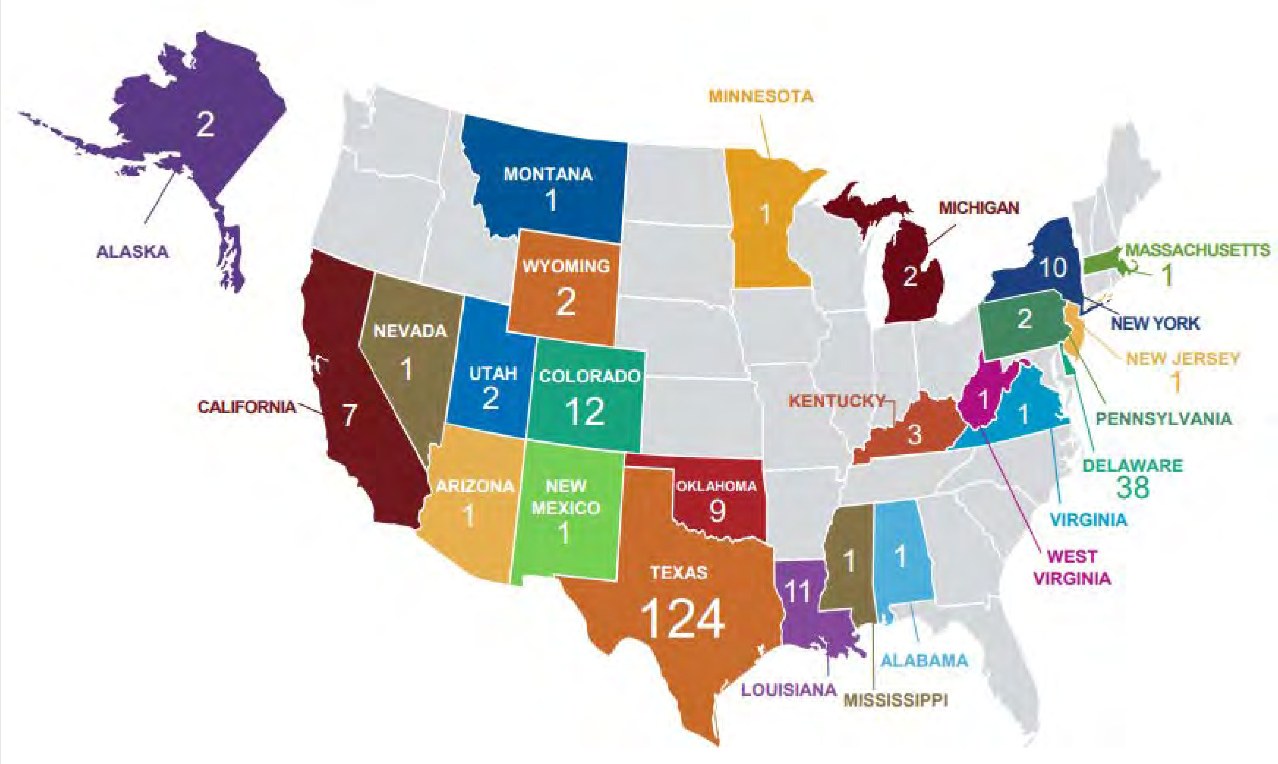
But his fellow Commissioners opposed the move. Chairman Wayne Christian said that because Texas accounts for only about 5 percent of global production, a statewide rationing program would have little impact on prices or worldwide oil supplies.

“By allowing the free market to work, producers can determine for themselves what level of production is economical,” Christian wrote in the Houston Chronicle.[37] He claimed companies were already cutting production on their own.

They also were facing mounting financial hardships, which could lead to more orphan wells. Companies slashed spending, curtailed drilling programs and in the months that followed laid off 118,000 workers, almost 40,000 of them in Texas.[38] As the year wore on, more companies began to file bankruptcy—Chesapeake Energy, Whiting Petroleum, Diamond Offshore Drilling, California Resources Corp.—a total of 23 producers in the first eight months of 2020, representing some $49 billion in aggregate debt.[39]

Since 2015, 124 Texas-based oil and gas companies have filed bankruptcy, more than all other states combined, and their combined debt is more than $117 billion.[40]

Figure 1 2015 – 2020 E&P Bankruptcy Filings by State as of November 30, 2020. (Adapted from Hayes and Boone, LLP)



What's more, banks and other secured lenders hold much of the debt that's driving producers into bankruptcy, which could indicate more contentious restructurings and assets sales as they move through the reorganization process.[41]

Combined with the waiver on fees and surcharges for environmental cleanup, the industry is in an increasingly precarious financial position, and Texas faces the prospect of more wells being orphaned by companies that had made no commitment to ensure their remediation.

c. Bankruptcies impact the state budget

Despite years of economic diversification, oil and gas production remains a significant source of revenue for the state, counties and local school districts. Texas taxes oil and natural gas production at 4.6 percent and 7.5 percent of the market value, respectively. In addition, the state levies a tax on oil well services at 2.42 percent of the gross receipts for those services.[42] In Fiscal Year 2020, those taxes generated almost $4.2 billion in revenue, or about 3 percent of total state revenue. The impact of the drilling slowdown was already beginning to affect state coffers. Collections from oil production fell 16.9 percent from a year earlier and natural gas collections plunged 45.1 percent. Total state revenue dipped 1.5 percent.[43]

Table 1 Fiscal Year 2020 oil and gas-related revenue to the state budget.
Source: Texas Comptroller of Public Accounts Data Visualization Dashboard.

Revenue Description	Total[4]
Motor Fuel Taxes	$3,525,000,000
Oil Production Tax	$3,229,000,000
Land Income[1]	$1,716,000,000
Natural Gas Production Tax	$925,000,000
Oil Well Service Tax	$119,000,000
Railroad Commission Agency Revenue[2]	$118,000,000
State Energy Marketing Program	$49,000,000
Misc oil and gas related[3]	$3,000,000
Total Oil and Gas Related Revenue	$9,685,000,000
Total State Revenue	$336,834,000,000
Oil and gas related revenue percent of state revenue	2.9%

[1] Includes only oil and gas related income
[2] Includes fees or other income that is oil and gas related, does not include agency revenue that is administrative in nature such as returned checks or vehicles sold.
[3] Includes the Automotive Oil Sales Fee and Interest on Oil Overcharge Loans.
[4] Totals are inexact due to rounding

Oil and gas taxes and royalties are the state's fifth largest source of income, and the money collected pumps billions into the Economic Stabilization Fund, commonly called the Rainy Day Fund.[44] Taxes and royalties also support the State Highway Fund, which pays for highway construction and maintenance, a vital part of the network supporting the state's $328.9 billion export market, which accounts for 17.4 percent of the gross state product, roughly double the U.S. average.[45]

In addition, schools and universities are supported by the Public University Fund and the Public School Fund, which receive royalties from oil and gas produced on state lands. In Fiscal 2019, those royalties added more than $1 billion to each fund.[46] School districts and counties also collect property taxes from oil and gas properties, pipelines and gas utilities. In 2019, the taxes generated over $2 billion for school districts and over $688 million for counties.[47]

The Railroad Commission's laissez-faire approach allows abrupt and unpredictable changes in the state's oil and gas revenue, resulting in a broad impact on essential state services. Had the commission implemented production quotas in April 2020, it could have stabilized wellhead prices for operators. That might have allowed some companies to avoid or delay bankruptcy and cushioned the impact on the state budget. As the regulator for the biggest oil-producing state, action by the Commission might also have encouraged its counterparts in other states to enact similar quotas. While it's unlikely it would have affected oil prices globally, it could have shored up prices in regional markets, easing the financial pressure on some operators.

III. The Railroad Commission Must Act to Prevent Insolvent Operators from Transferring Liability to Taxpayers

In theory, bankruptcy doesn't absolve companies of cleanup responsibilities. When a producer goes bankrupt, its creditors line up at the courthouse, where they're basically assigned an order of priority based on the type of money they're owed by the bankrupt company, known as "the estate."

Creditors with the highest priority get paid first, starting with those whose claims are secured by assets that were posted as collateral for loans to the company. It's similar to a home mortgage, in which a bank can repossess a homeowner's property if they fail to make mortgage payments. In bankruptcy, secured creditors simply claim their collateral and hope that the value is enough to cover what they're owed.

Next in line are administrative claims, which are obligations a company must meet to continue operating, such as employee wages and taxes, followed by unsecured claims, which include payments to vendors and loans such as lines of credit that aren't secured with collateral. Stockholders are generally at the end of the line, and they rarely receive any payment for their shares in a bankruptcy reorganization.

A judge oversees the orderly distribution of funds from the estate to the various creditor groups.

Typically, environmental liabilities receive special treatment, known in legal parlance as a "super priority," meaning they vault ahead of other creditors, falling into the second tier of administrative claims. (Unpaid environmental fines at the time of the bankruptcy filing, however, can be dismissed as unsecured claims.) The bankruptcy process basically links the liability for cleanup to the property itself. If the estate sells it, the buyer assumes the responsibility for cleanup—or at least, that's how it's supposed to work. The high number of orphaned wells in the Railroad Commission's queue indicates that isn't always the case.[48]

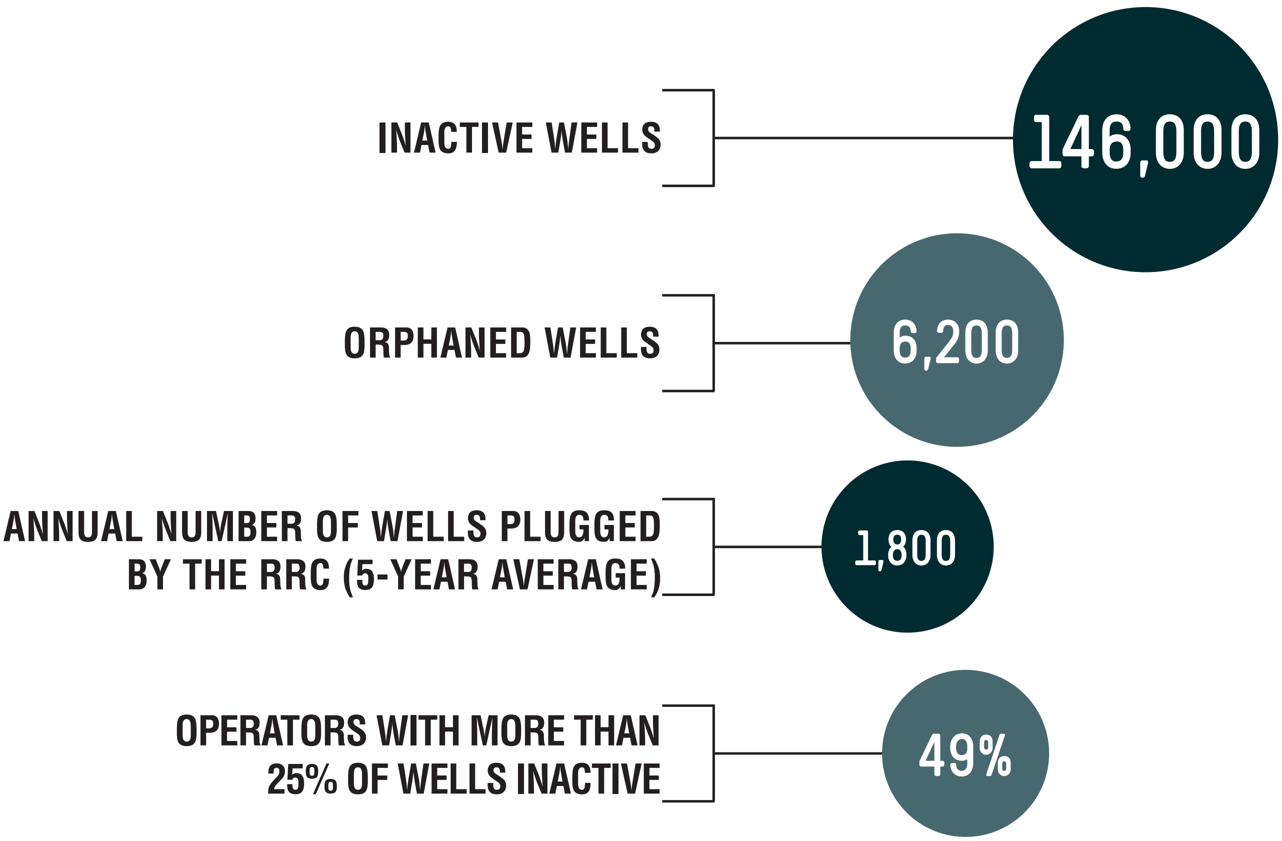
a. Companies can shuffle liability outside of bankruptcy

Already, the oil industry has begun to employ tactics similar to the coal industry's for avoiding liability. One of the biggest oil patch bankruptcies of 2020 is California Resources Corp., which was spun off from Houston-based Occidental Petroleum in 2014. CRC was stumbling under almost $5 billion worth of debt that was due at the end of 2022, and it burned through some $283 million in free cash. But CRC's demise didn't affect Oxy, its former parent. When CRC was set up, it borrowed $6 billion and paid that money to Oxy, which then washed its hands of its former subsidiary, as well as the liability for the 18,000 wells that CRC owns—some 6,000 of which are idle.[49]

CRC filed for bankruptcy in Texas, although the company's operations are in California. Texas regulators should be paying attention to the case, because something similar could happen with other producers, potentially leaving thousands or tens of thousands of orphan wells for the state to plug.

That's a concern because the Railroad Commission identified more than 6,200 orphan wells at the end of FY 2020,[50] but the Oil Field Cleanup Program has averaged an annual plugging rate of less than 1,800 during the past five years.[51] And there could be more on the way. The number of operators with more than 25 percent of their wells listed as inactive—the first step in a well becoming orphaned—rose to 49 percent by the end of Fiscal Year 2020 from 42 percent three years earlier.[52]

2020 BY THE NUMBERS



The Commission has assumed the number of inactive wells will remain steady at about 140,000 per year for the 2022-2023 biennium.[53] However, its own rules may be keeping it from understanding the potential for growth of orphaned wells. In 2016, the Commission changed Statewide Rule 15 to cut the threshold defining an inactive well in half: five barrels of oil per month instead of 10, and 50,000 cubic feet of gas per month instead of 100,000 over three consecutive months.[54] The change results in a lower number of "stripper wells," or marginal producers, that might ordinarily count toward the Commission's projection of potential orphan wells.

While environmental liabilities aren't supposed to be dismissed in bankruptcy, things don't always work the way the laws were designed. Consider the case of Houston-based EP Energy, one of the biggest producers in the Eagle Ford Shale of South Texas. EP filed for bankruptcy in October 2019,[55] but it didn't earmark any funds for well cleanup. The U.S Department of the Interior filed a motion noting that the decommissioning of wells on 12 EP offshore leases in the Gulf of Mexico were overdue, but it hadn't determined the plugging and reclamation costs for EP's onshore leases.[56] In other words, even though the company was already in bankruptcy, the status of its environmental obligations hadn't been determined by regulators.

The finances of the oil patch seem to be worsening faster than regulators' ability to monitor them. As more debt comes due in the next couple of years, the steady rise in oil patch bankruptcies is likely to continue through at least 2022.[57] By the end of that year, the number of filings nationwide could top 190, or roughly equal to the total of the past five years.[58] As a result, the scale and cost of potential environmental liabilities passed on to state and federal agencies could be far greater than they appear.

Meanwhile, oil prices began rising at the end of 2020, and topped $50 a barrel for the first time in almost a year. With the higher prices, smaller producers may feel emboldened to buy aging oil leases being sold by larger companies. If prices fall again, these older wells have a greater risk of becoming orphaned because the new owners have fewer resources to plug them. As a result, the scale and cost of potential environmental liabilities passed on to state and federal agencies could be far greater than they appear.[59]

b. The Railroad Commission waived plugging rules

The industry's deteriorating finances and the detrimental effects of depressed commodity prices on the state budget didn't stop Commissioners at a May 5 hearing from waiving the rules requiring that inactive wells be plugged, and pits remediated within a year. Nor did it stop them from suspending fees and surcharges operators pay that cover the plugging and remediation costs. The public, however, had little notice that Commissioners were even thinking of such measures because the only announcement was a cryptic public notice that they were considering "possible action," citing the COVID-19 pandemic as an excuse for taking emergency measures.[60] However, since the rules were initially enacted by the Legislature, it appears the Commission lacked the authority to waive the rules. In July, the consumer advocacy group Public Citizen and two landowners sued the Commission, claiming the waiver violated the Texas Open Meetings Act, the Texas Administrative Procedure Act and the Texas Natural Resource Code by failing to give proper public notice of the vote. The lawsuit called for the Commission to reinstate the rules for plugging wells and schedule public hearings before considering a waiver in the future.

One of the plaintiffs, Hugh Fitzsimons III, called the Commission's actions "reckless and irresponsible," saying it increases the risk to groundwater statewide. Fitzsimons is part owner of a ranch in Dimmit County, on the Texas-Mexico border, that has more than 100 inactive oil and gas wells. He raises bison, produces guahillo honey and grows olives on the land, and he worries that the wells could pose a threat to those activities.[61]

"It is a simple and irrefutable fact that once your water is contaminated you have no ranch," he said.[62]

As a member of the Wintergarden Groundwater Conservation District, which covers Dimmit and two surrounding counties, Fitzsimons has seen the impact of increased drilling in the Eagle Ford Shale, one of the most active basins for fracking in Texas.[63] He recalls an incident in 2011 in which carcinogenic fracking fluid from an injection well migrated into an abandoned well nearby. The "breakout" produced a sludge, resembling chocolate pudding, that came within a hair's breadth of contaminating the Carrizo Aquifer,[64] a key source of drinking water and irrigation for the Wintergarden, a multi-county region whose temperate climate makes it one of the country's biggest year-round suppliers of vegetables.[65]

By waiving fees and surcharges, the Commission essentially created a hole in the revenue for the cleanup program of at least $400,000. Although the size of that hole remains uncertain, it comes amid financial difficulty and a looming state budget shortfall and casts further doubt about the viability of the bonding program, which is supposed to be self-supporting.

Despite the economic slowdown and weak prices, drilling activity in the state continues apace. In the first nine months of 2020, operators drilled more than 9,200 new wells, up from less than 6,500 for the same period a year earlier.[66] The rate of permitting, however, slowed to about 20 a day in midsummer from 60 day at the start of 2020.[67]

Apart from the lost revenue for future cleanup costs, waiving the fee requirements could be sending the wrong message to the industry at a critical time. In particular, the smallest firms, which often operate with the least environmental safeguards, and have the most limited financial resources, may leave the business without plugging wells that carry greater environmental risk because of their age or poor maintenance history.

Small producers tend to cause a larger share of environmental incidents, and one study by economists at the University of California, San Diego, found that bonding programs can reduce the number of orphan wells by 70 percent and the violations of clean water regulations by 25 percent.[68]

The Commission's decision to waive the plugging requirements came as several factors were converging on the state's oil and gas industry that would compound the concerns about the cost of orphaned wells.

c. The Oil Field Cleanup Fund has fallen behind

Molly Rooke's family has owned a ranch in Refugio County, on the Texas Gulf Coast, since before Texas joined the United States in 1845. The ranch is dotted with dozens of unplugged, abandoned wells, and the family for years requested the Texas Railroad Commission's help in plugging them.[69] In 2019, one of the wells blew out, spewing volatile chemicals into the air and contaminating nearby wetlands.

Rooke called the Commission to no avail. Only after drawing media attention to the problem did commissioners send workers to temporarily shut in the well. Rooke waited for more than a year for the crew to return and permanently plug the well.[70] "I thought there would be better communication and cooperation," Rooke said. "I didn't think it would take so long."

That well, and others like it on her ranch, are "ticking time bombs," Rooke said.[71]

Orphan well blow out on Molly Rooke's ranch, 2019. Photo courtesy Molly Rooke.

Unfortunately, the delays Rooke experienced aren't unique. As the number of abandoned wells has increased, the Commission has fallen farther behind in its efforts to plug orphaned wells and clean up other contaminated sites related to oil and gas drilling around the state.

Concerned about the cost of environmental remediation when, such as in Rooke's case, the operator of an errant well is no longer around to hold accountable, the Texas Legislature established the Oil Field Cleanup Fund in 1991 (now called the Oil and Gas Regulation and Cleanup Fund) to combat the pollution threat from abandoned wells, pits, storage tanks and other sites related to oil and gas exploration that might require remediation. The idea was straightforward: use a percentage of the fees the Railroad Commission already collected from drilling permits and production fees and earmark it for cleanup. It was one of the first such programs in the country, and until recently, it was one of the most effective.

By fiscal 1999, the fund was generating between $10 million and $13 million a year, or about 25 percent of the Commission's operating budget. During its first eight years, the fund paid for plugging more than 11,000 abandoned wells and cleaning up more than 1,300 polluted sites.

At the same time, the Commission also recreated a requirement that operators post a surety bond to cover potential cleanup costs. Studies have found that such bonding programs can be effective in creating a deterrent to contamination.[72] However, the Commission doesn't require operators to post bonds for all wells, and most of the orphan wells the Commission must pay to plug are owned by unbonded operators.[73] In addition, the bond revenue that is collected covers less than 16 percent of the actual plugging costs.[74]

While the oil and gas industry tacitly supported the bonding program, it also lobbied to waive some of the requirements, arguing that the rules put too much of a financial burden on small operators. Ironically, small operators are more likely to abandon problem wells than large companies.[75]

An orphan well on Molly Rooke's ranch remains with rusted and broken parts protruding from the surface. Photo courtesy Molly Rooke.

Although Texas has—on paper—one of the strictest bonding programs among oil-producing states,[76] it has not adjusted the programs terms to account for additional costs or environmental hazards posed by hydraulic fracturing and horizontal drilling.

Bond terms start as low as $25,000 a year for 10 wells or fewer, and go to $250,000 for operators with 100 wells or more.[77] In other words, a company may be bonded for as little as $2,500 on a well that may cost almost 10 times as much to clean up.

Because they aren't explicitly required to plug inactive wells, companies have some wiggle room to game the system. Operators must file a report, known as a W-10, with the Commission for every producing well. Unscrupulous companies can simply falsify a W-10, indicating the well has returned to production, then reclassify it later as shut-in, to restart the 10-year clock. Given that there may be dozens or even hundreds of wells in a particular field, it's unlikely the Commission would catch the falsified W-10.[78]

In 2008, the state had fewer than 157,000 producing wells. A decade later, that number had surged by almost 30,000, a rate of increase unseen since 1985, the peak for drilling activity in Texas.[79]

Unlike conventional wells, fracking technology incorporates acids, biocides, gelling agents and corrosion inhibitors.[80] The U.S. Environmental Protection Agency has identified more than 1,000 different chemicals used in the fracking process over the years.[81] Some of these chemicals are considered "trade secrets" by the drilling services companies, and the public has received at best scant information about their potential human health risks.

The depth of shale formations and the length of the horizontal well bores used in unconventional oil and gas development has raised the cost of plugging wells, which has more than doubled since 2008, to between $20,000 and $40,000 per well.[82] Some estimates, however, say the cost could be as much as five times greater.[83]

If the wells on Rooke's property were still owned by a company, the operator might face fines or legal action by the Commission. In 2020, it reported more than 30,000 violations for which it issued penalties or took other action, and more than 1,600 were referred for legal action. Only 59 were considered major.[84]

By 2000, the state had at least 17,000 abandoned wells, and the cleanup fund, which also pays to remediate abandoned sites, faced a potential liability of $540 million.[85] The Commission identified about 7,000 more wells as “non-compliant,” meaning operators had not paid the proper fees or filed the appropriate paperwork and the wells were slated for review to determine if they needed plugging. However, the Commission’s staff also acknowledged that the actual number of abandoned wells was probably far greater, because many were abandoned before reporting was required. As a result, the staff estimated that another 200,000 abandoned wells needed plugging. The staff estimated that plugging only the 17,000 that they already knew about would take 12 years and cost of about $76.5 million.[86]

Currently, when the Commission files complaints against operators who make false production reports, operators can protest the action and request a public hearing. The Commission doesn’t track data specifically related to filing false reports related to inactive wells, and for the actions it does bring, its enforcement rate is low. Although inspectors in Texas find more violations per inspection than their counterparts in other states, between 2006 and 2010, fewer than 1 percent of all violations identified by the Commission staff were referred for enforcement.[87]

Many oil companies now collect well production data in real time, yet the Commission lacks the capability to access this real-time data. By using real-time well data, the Commission could better ensure that its regulations are being followed by operators and that well data is up to date.

In some cases, operators sell their low-performing wells to buyers that squeeze out all the remaining oil, sell off the equipment, and never plug or remediate the well sites. Operators simply have no incentive to comply with the rules because of the scant rate of enforcement. The fines the Railroad Commission does issue tend to be so meager that they aren’t a deterrent.[88]

If a property is sold, the new operator has six months to bring wells into compliance by either plugging them or returning them to production.[89]

While the Commission insists that bankruptcy doesn’t absolve operators of cleanup liability, it can make it harder for the state to ensure that operators pay to properly plug and abandon wells.[90] More importantly, the Commission’s lack of oversight and enforcement over sales and bankruptcies may lead to wells becoming orphans.

d. The Railroad Commission turns to taxpayers for well cleanup

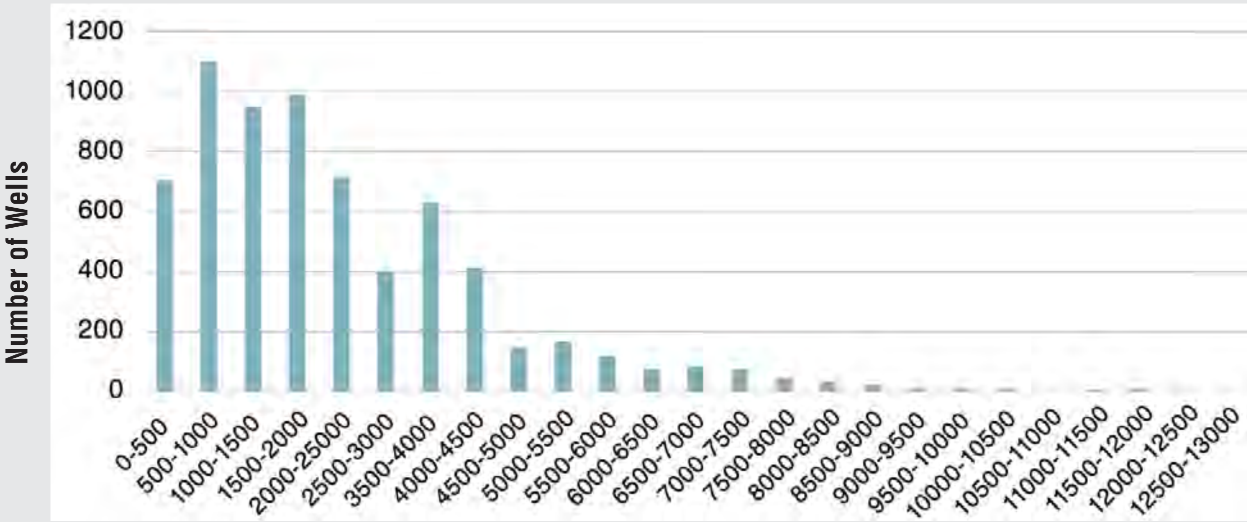
According to the Commission’s forecasts, the 6,200 orphan wells it identified in fiscal 2020, will rise to about 6,500 over the next biennium. In addition, the Commission assumes that the number of inactive wells in 2022 and 2023 will hold steady at about 140,000.[91] With rising bankruptcies and distressed asset sales in the industry, the chance for some of those inactive wells to become orphaned is rising.

While the Commission plugged fewer than 1,500 wells in fiscal 2020, it identified more than 1,900 others that were candidates for plugging.[92] The Commission staff prioritizes plugging based on the potential risks to public safety and the environment, and it estimates it will plug about 1,400 wells per year in the next biennium.[93,94]

The costs of plugging orphaned wells has risen significantly in the past five years. In 2015, the Commission paid less than $16,000 each to plug 692 wells,[95] and in 2020 it paid an average of almost $21,000 per well to plug 1,477 wells.[96] Commission data shows most wells it plugged were less than 4,000 feet deep, far shallower than most wells being drilled today.[97] As a result, the current cost of plugging wells may be a poor indicator of future expense.

Figure 2

FY 2015 - FY 2020 Depth of Plugged Wells



Bottom Well Depth (feet)

In addition to the well costs, the Commission also pays to remediate pits and other pollution sites, which cost $8.6 million in fiscal 2020.[98] In total, the Commission spent about $50 million for well plugging and site cleanup combined,[99] which is more than double the $19 million it paid in fiscal 2015.[100] Even though its spending more, it isn't keeping pace with the growing number of orphan wells.

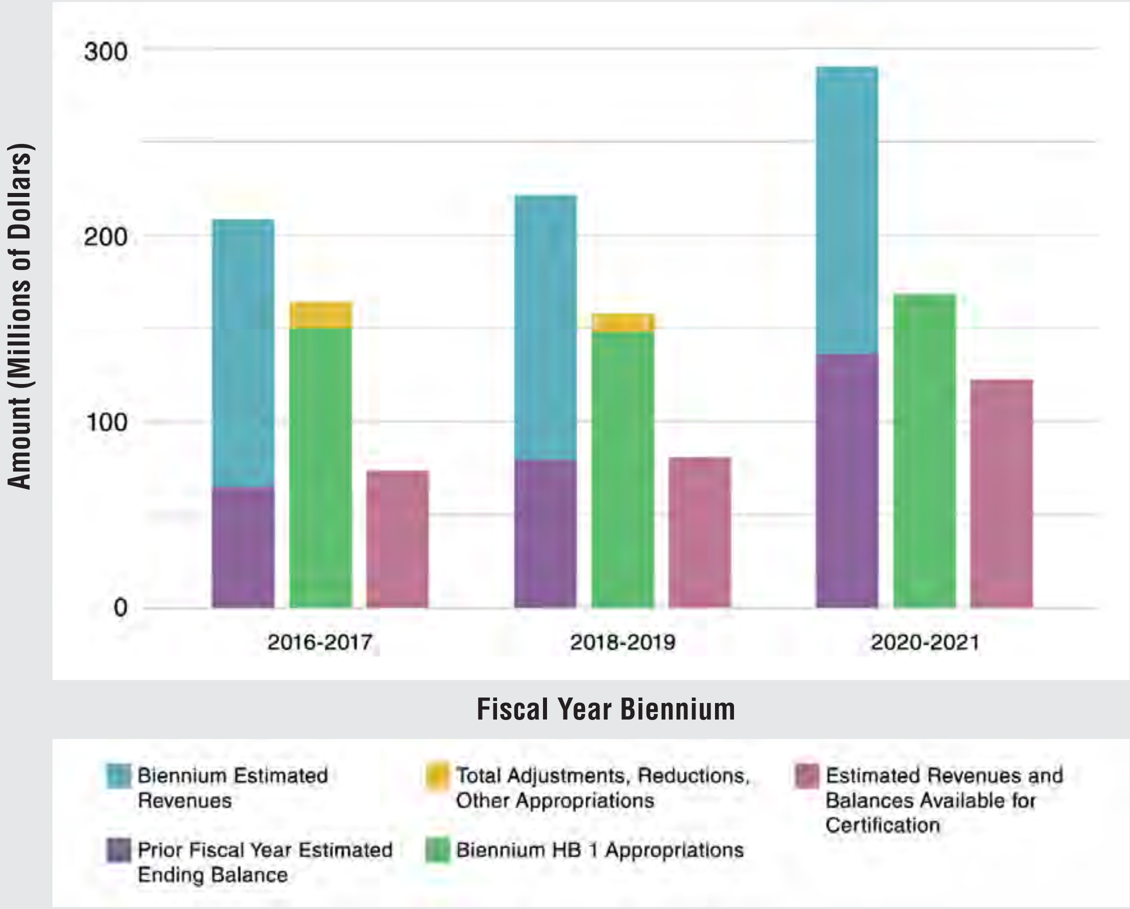
As the fortunes of the oil and gas industry have fluctuated, so has the balance of the cleanup fund. The downturn in industry fortunes in 2020 has curtailed contributions to the fund, even as company bankruptcies and the costs of plugging orphan wells continue to rise.

While orphan wells remain the focus of the plugging program, another concern is the estimated 37,000 wells that have been inactive for a decade or more.[101] If those wells become orphaned, the Commission's own estimates show plugging costs could exceed $2.3 billion.

The cleanup fund's revenue has increased steadily in recent years, though preliminary figures indicate 2020 revenue may have dipped by about 6 percent.[102] This caused the fund's year-end balance to jump from $64.1 million, in 2015 to $139 million in 2020.[103,104] Unfortunately, even with a rising surplus, the Commission must set aside revenues from bonds and other forms of financial assurance. With a more limited OGRC fund, the Commission had to request General Revenue Funds for its well plugging and remediation program for the 2022 – 2023 biennum.[105]

Figure 3

Over the past three biennia, the Oil and Gas Regulation and Cleanup fund has grown, but the Commission must retain bonds and financial assurances in its account. As such, the balance is used to certify the state's budget.

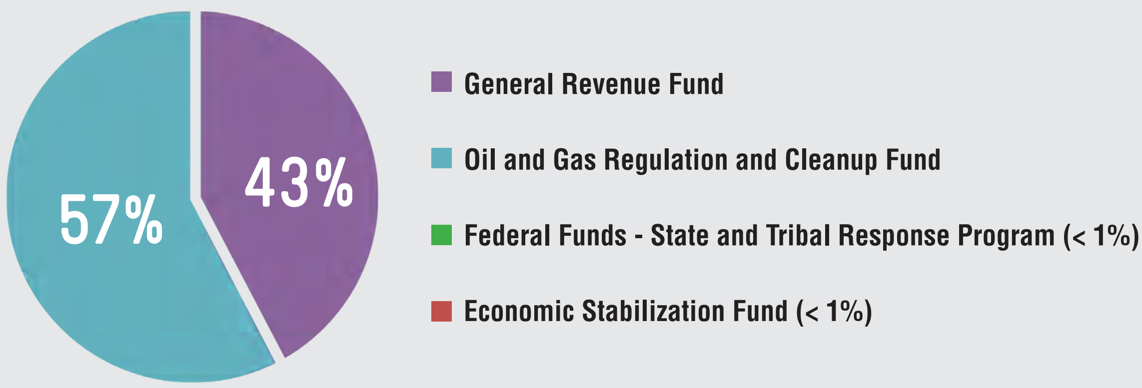


Source: Texas Comptroller of Public Accounts. Report on Use of General Revenue Dedicated Accounts.

For the 2022-2023 biennium, the Commission has requested total expenditures for well plugging and remediation, of more than $114 million, which includes the cost of administering the program, such as staff salaries and supply costs and storage, in addition to the actual plugging and remediation expenses. That budget request is about $29 million less than the Commission requested in the previous budget cycle.[106]

Figure 4

Oil and Gas Well Plugging and Remediation - Method of Financing



Source: Railroad Commission of Texas - Legislative Appropriations Request Fiscal Years 2022-2023

Plugging costs are funded by more than 20 sources of revenue, including the bonding program, oil production taxes, fines for regulatory violations and various fees.[107] Once collected, these fees—about $65 million for the next biennium—go into the OGRC Fund for well plugging and remediation.[108] In addition, the Commission has requested about $49 million from the General Revenue Fund for this purpose.[109]

Moreover, the Commission has acknowledged that depressed commodity prices in 2020 could adversely affect cleanup fund revenue. Something similar happened in 2016, when oil prices fell to a low of $26.21 per barrel. Fund revenue declined, and the Commission registered an $18.7 million revenue shortfall. “While the experience of Fiscal Year 2016 offers some indication of what the Commission may face regarding a revenue shortfall, at this time any estimate of future revenue for the Oil and Gas Regulation and Cleanup Fund carries uncertainty,” the Commission said.[110]

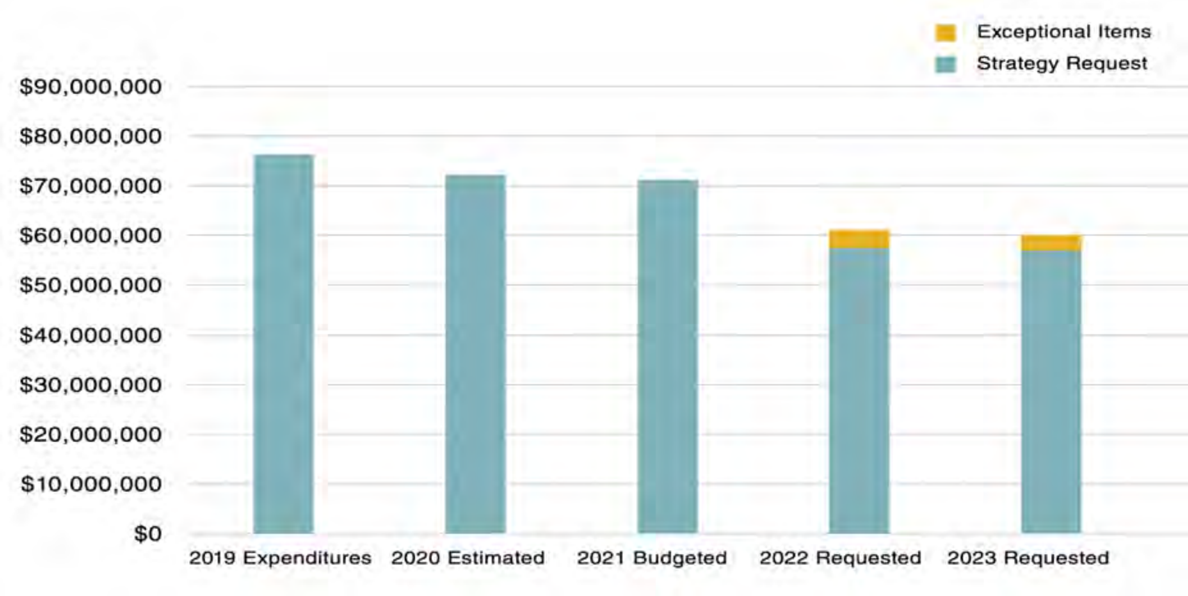
Because of the uncertainty and across-the-board budget cuts statewide, the Commission deferred cleanup activities for the largest projects and focused on smaller ones.[111] This, however, is not a sustainable strategy.

The rising cost of plugging orphan wells combined with the potential financial fallout from the Commission’s decision to waive fees and cleanup requirements comes amid mounting budget difficulties for the state. In July 2020, Texas Comptroller Glenn Hegar projected a $4.58 billion shortfall for Fiscal Year 2021, as weak oil prices and the COVID-related economic slowdown took their toll. All state agencies, including the Railroad Commission, were instructed to cut their spending by 5 percent from their fiscal 2020 appropriations.[112] Aligned with the instruction, the Commission reduced its 2022 – 2023 Legislative Appropriations Request (LAR) for the well plugging and site remediation program by 20 percent (Figure 1). The Commission included an exceptional item request for Oil and Gas Well Plugging and Remediation to complete "one large cleanup project and begin work on a second project during the 2022-23 biennium."[113] The increase, however, was not enough to bring the total Oil and Gas Well Plugging and Remediation Request up to previous years' expenditure levels.

In January 2021, fears about the state's budget deficit became less dire when Hegar announced only a $1 billion deficit (not accounting for the prior 5 percent budget cuts agencies were asked to make in FY2020).[114] It's not clear if this improved outlook would boost the Commission's Well Plugging and Remediation Appropriations.

Figure 5

RRC Oil and Gas Well Plugging and Remediation Expense Legislative Appropriations Request, 2022 - 2023



Source: Railroad Commission of Texas - Legislative Appropriations Request Fiscal Years 2022-2023

Even as economic conditions create an environment ripe for oil and gas bankruptcies, the Commission is not in a position to improve its oversight of well plugging and site remediation. Without a structural change in how well plugging and site remediation is funded, taxpayers could wind up footing more of the bill in the future as oil and gas development declines —or worse, the wells could be left unplugged and sites unremediated.

IV. Other States Provide Solutions

Determining the number of abandoned wells nationally is difficult because of reporting lapses, classification issues and conflicting data. However, two studies cited by the U.S. Environmental Protection Agency puts the number of abandoned wells nationally at between 2.6 million and 3 million[115]—some of which may be more than 100 years old.[116]

Plugging these wells not only protects public health, safety and groundwater, it also could significantly reduce the release of methane, a major contributor to climate change. The EPA estimates that unplugged and abandoned wells nationwide emit, on average, 280,000 metric tons of methane annually, or roughly the carbon emissions of 2.1 million passenger cars.[117]

Several attempts to improve orphan well cleanup have been proposed at the federal and state levels. In September 2020, Sen. Michael Bennet, a Colorado Democrat, introduced a bill that would create a nationwide cleanup fund to help states, tribes and federal agencies remediate well contamination on federal and private lands.

The new fund would be overseen by the Interior Department and would boost statewide blanket bond requirements by $200,000. Those requirements would be reviewed regularly and adjusted to keep up with inflation and ensure the program had funds to cover remediation claims.

It also would create a standard definition of an inactive well and set rules for when cleanup must begin.[118] Bennet believes the bill would create new jobs and reduce methane emissions.[119]

Because of the 118,000 energy industry jobs lost nationwide since the pandemic began,[120] regulators, industry groups and environmentalists are looking to tap the expertise of those laid off workers to bolster cleanup programs. The Center for American Progress, a left-leaning think tank, estimates that a $2 billion nationwide orphan well cleanup program could support 14,000 to 24,000 jobs in oil- and-gas-producing states.[121] The idea of paying laid off oil workers to plug orphaned wells has also been endorsed by the U.S. House of Representatives Natural Resources Committee and the Interstate Oil and Gas Compact Commission, a group of 31 oil and gas producing states.[122]

President Joe Biden has proposed that the government could put as many as 250,000 people to work plugging orphaned oil and natural gas wells and cleaning up other environmental hazards.[123]

In Montana, one former oil and gas manager set up a nonprofit, the Well Done Foundation, to coordinate the plugging of orphaned wells.[124] Similarly, a new nonprofit in Texas, Native State Environmental, is raising funds to help landowners pay the cost of plugging orphan wells.[125]

In Wyoming, state lawmakers considered boosting their reclamation program in hopes of spurring job growth and economic development. Wyoming has a bond program similar to Texas, but with a far larger balance—$159 million.[126] At the same time, the state has only 25,600 oil and gas wells.[127] In other words, its cleanup has more than five times the money that Texas has allocated, even though Texas has almost 20 times the number of active wells.

In mid-2020, the Wyoming Legislature proposed boosting the fund even more, by allocating an additional $7.5 million for accelerating orphan well cleanup. Wyoming had almost 2,800 orphaned wells at the time.

Similar to Bennet's plan, lawmakers suggested using the additional money for hiring displaced oil and gas workers to help with the expanded plugging program, a measure supported by a key industry trade group.

In a news release, the Petroleum Association of Wyoming said: "This would make sure employees in the energy service industry continue to take home a paycheck and are ready to restart drilling as demand returns, while also taking advantage of time and cost benefits of reducing the orphan well backlog—a liability the industry takes seriously."[128]

These programs could provide a framework that the Railroad Commission could use to strengthen its well cleanup program in Texas.

V. Conclusion

The Railroad Commission failed to adjust its orphan well program at the onset of the fracking boom, setting the state up for a disaster with the current oil and gas industry decline. While other states are looking at innovative programs to employ laid off industry workers to accelerate the plugging of abandoned wells, Texas continues to use the same formula it has for years.

But that formula hasn't kept pace with the growing number of wells that need plugging and sites that need remediation. As a result, funds allocated for the effort are not enough to keep up with current or future needs. Even as bankruptcies increase, the Commission has asked the Legislature for fewer funds, and it is requesting money from the General Revenue Fund for well plugging and site cleanup at a time when the state faces a significant budget shortfall.

The Commission's only action to address the dire state of the industry in the past year was to waive plugging requirements and surcharges and fees that help pay for environmental cleanup. Thankfully, on Dec. 8 state district Judge Jan Soifer barred the Railroad Commission from enforcing the three orders it adopted at its May 5 meeting. The judge determined that Railroad Commission violated the Texas Open Meetings Act by not specifying in the meeting notice which rules it intended to suspend. Railroad Commission is appealing the judge's finding and a trial is set for May 10. Though the Railroad Commission disagrees that it provided insufficient meeting notice, it attempted to remedy the violation by ratifying a revised notice retroactively on January 6, 2021.[129] Public Citizen contends that retroactively posting the appropriate language is not a sufficient remedy to the Commission's violation of the Texas Open Meetings Act.[130]

The Commission's decision to waive rules for struggling operators and appeal Soifer's order makes the state of the cleanup program all the more precarious. The Commission's actions create the potential for those costs to be shifted to the Commission and, ultimately, the taxpayer.

At the same time, declining revenue from oil and gas taxes and royalties could have a growing impact on state, county and school district funding, underscoring a broader need for Texas to develop a plan for weaning education and highway projects off of oil and gas-related revenue.

These are extraordinary times in the industry, and the Commission needs to fulfill its mandate to protect the state's natural resources and ensure economic vitality. That means taking steps to ensure Texas' growing orphan well problem doesn't pose a significant long-term risk to Texas landowners, taxpayers and the environment.

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Exhibit 16.03

This exhibit was not previously submitted in November 2023

2012 TX REG TEXT 284373 (NS)

Texas Regulation Text - Netscan
16 TAC 3.107
Proposed
February 10, 2012
Economic Regulation

The Railroad Commission of Texas (Commission) proposes new s.3.107, relating to Penalty Guidelines for Oil and Gas Violations. On October 25, 2011, the Commission authorized staff to draft a proposed new rule to implement guidelines to be considered by the Commission in determining the amount of administrative penalties for violations of Texas Natural Resources Code, Title 3; the provisions of Texas Water Code, Chapters 26, 27, and 29, that are administered and enforced by the Commission; or the provisions of a rule adopted or order, license, permit, or certificate issued under Texas Natural Resources Code, Title 3, or Texas Water Code, Chapters 26, 27, and 29. During the 82nd Legislative Session, the Sunset Commission recommended that the Commission adopt its penalty guidelines in rule form, and that the rule should assign penalties to violations based on their risk and severity. With the proposed new rule, the Commission seeks to align all penalty guidelines with existing Pipeline Sa

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TITLE 16.ECONOMIC REGULATION

PART 1. *RAILROAD COMMISSION OF TEXAS*

CHAPTER 3. *OIL AND GAS DIVISION*

16 TAC §3.107

The Railroad Commission of Texas (Commission) proposes new §3.107, relating to Penalty Guidelines for Oil and Gas Violations. On October 25, 2011, the Commission authorized staff to draft a proposed new rule to implement guidelines to be considered by the Commission in determining the amount of administrative penalties for violations of Texas Natural Resources Code, Title 3; the provisions of Texas Water Code, Chapters 26, 27, and 29, that are administered and enforced by the Commission; or the provisions of a rule adopted or order, license, permit, or certificate issued under Texas Natural Resources Code, Title 3, or Texas Water Code, Chapters 26, 27, and 29. During the 82nd Legislative Session, the Sunset Commission recommended that the Commission adopt its penalty guidelines in rule form, and that the rule should assign penalties to violations based on their risk and severity. With the proposed new rule, the Commission seeks to align all penalty guidelines with existing Pipeline Safety Division penalty guidelines, creating consistency and transparency agency-wide. The Commission proposes new §3.107 to provide a matrix for oil and gas rule violations.

The matrix includes typical penalty amounts for violations of the statutes cited above or the provisions of a rule adopted or an order, license, permit, or certificate issued under those statutes, as well as guidelines for penalty enhancements based on the severity of the violation, the culpability of the person charged, any prior violations within past seven years, and the amount of previous penalties for violations within the past seven years.

Proposed new subsection (a) states the Commission's policy on compliance and enforcement. Improved safety and environmental protection are the desired outcomes of any enforcement action. Encouraging operators to take appropriate voluntary corrective and future protective actions once a violation has occurred is an effective component of the enforcement process. Deterrence of violations through penalty assessments is also a necessary and effective component of the enforcement process. A rule-based enforcement penalty guideline to evaluate and rank oil- and natural gas-related violations is consistent with the central goal of the Commission's enforcement efforts to promote compliance. Penalty guidelines set forth in this section will provide a framework for more uniform and equitable assessment of penalties throughout the state, while also enhancing the integrity of the Commission's enforcement program.

Proposed new subsection (b) provides that the penalty amounts contained in this section are provided solely as guidelines to be considered by the Commission in determining the amount of administrative penalties for violations of provisions of Texas Natural Resources Code, Title 3; Texas Water Code, Chapters 26, 27, and 29, that are administered and enforced by the Commission; or the provisions of a rule adopted or an order, license, permit, or certificate issued under Texas Natural Resources Code, Title 3, or Texas Water Code, Chapters 26, 27, and 29.

Proposed new subsection (c) provides that the establishment of these penalty guidelines shall in no way limit the Commission's authority and discretion to cite violations and assess administrative penalties. The typical penalties listed in this section are for the most common violations cited; however, this is neither an exclusive nor an exhaustive list of violations that the Commission may cite. The Commission retains full authority and discretion to cite violations of Texas Natural Resources Code, Title 3; the provisions of Texas Water Code, Chapters 26, 27, and 29, that are administered and enforced by the Commission; and the provisions of a rule adopted or an order, license, permit, or certificate issued under Texas Natural Resources Code, Title 3, or Texas Water Code, Chapters 26, 27, and 29, and to assess administrative penalties in any amount up to the statutory maximum when warranted by the facts in any case, regardless of inclusion in or omission from this section.

Proposed new subsection (d) lists factors the Commission considers in assessing a penalty. The amount of any penalty requested, recommended, or finally assessed in an enforcement action will be determined on an individual case-by-case basis for each violation, taking into consideration the person's history of previous violations; the seriousness of the violation; any hazard to the health or safety of the public; and the demonstrated good faith of the person charged.

Proposed new subsection (e) provides that regardless of the method by which the typical penalty amount is calculated, the total penalty amount will be within the statutory limit. This subsection also contains two tables. Table 1 shows the typical penalties for violations of provisions of Texas Natural Resources Code, Title 3; the provisions of Texas Water Code, Chapters 26, 27, and 29, that are administered and enforced by the Commission; and the provisions of a rule adopted or an order, license, permit, or certificate issued under Texas Natural Resources Code, Title 3, or Texas Water Code, Chapters 26, 27, and 29. Table 1A shows the derivation of the factors by which additional penalty amounts for violations of §3.73 of this title, relating to Pipeline Connection; Cancellation of Certificate of Compliance; Severance. The factors are based on four components which, in combination, yield the factor by which an additional penalty amount of $1,000 is multiplied. The various combinations of the components are set forth in Table 1A; the factors range from one to 10.

Proposed new subsection (f) provides that for violations that involve threatened or actual pollution; result in threatened or actual safety hazards; or result from the reckless or intentional conduct of the person charged, the Commission may assess an enhancement of the typical penalty. The enhancement may be in any amount in the range shown for each type of violation as shown in Table 2.

Proposed new subsection (g) sets forth penalty enhancements for certain violators. For violations in which the person charged has a history of prior violations within seven years of the current enforcement action, the Commission may assess an enhancement based on either the number of prior violations or the total amount of previous administrative penalties, but not both. The actual amount of any penalty enhancement will be determined on an individual case-by-case basis for each violation. The guidelines in Tables 3 and 4 are intended to be used separately. Either guideline may be used where applicable, but not both.

Proposed new subsection (h) authorizes a penalty reduction for settlement before hearing. The recommended monetary penalty for a violation may be reduced by up to 50% if the person charged agrees to a settlement before the Commission conducts an administrative hearing to prosecute a violation. Once the hearing is convened, the opportunity for the person charged to reduce the basic monetary penalty is no longer available. The reduction applies to the basic penalty amount requested and not to any requested enhancements.

Proposed new subsection (i) concerns demonstrated good faith. In determining the total amount of any monetary penalty requested, recommended, or finally assessed in an enforcement action, the Commission may consider, on an individual case-by-case basis for each violation, the demonstrated good faith of the person charged. Demonstrated good faith includes, but is not limited to, actions taken by the person charged before the filing of an enforcement action to remedy, in whole or in part, a violation or to mitigate the consequences of a violation.

Proposed new subsection (j) contains a penalty calculation worksheet. The penalty calculation worksheet shown in Table 5 lists the typical penalty amounts for certain violations; the circumstances justifying enhancements of a penalty and the amount of the enhancement; and the circumstances justifying a reduction in a penalty and the amount of the reduction.

Ramon Fernandez, Deputy Director, Oil and Gas Division, has determined that for each year of the first five years that the proposed new rule will be in effect there will be no fiscal implications for state government. The proposed new rule codifies penalty amounts, but the Commission does not anticipate penalty revenue to increase as a result. Revenue from administrative penalties is deposited to the State General Revenue Fund.

There are no fiscal implications for local governments.

Mr. Fernandez has also determined that for each year of the first five years the proposed new rule will be in effect, the public benefit anticipated as a result of enforcing the new rule will be an improvement in safety due to an increased awareness of both the importance of complying with oil and gas safety standards and practices and the potential penalties associated with not doing so. By establishing typical penalty amounts for additional violations of the oil and gas rules and increasing the typical penalties for some current violations, the Commission finds that the proposed new rule could result in a reduction in the number of violations and a corresponding increase in public safety.

The Commission has also developed an analysis of the probable economic cost to persons required to comply with the proposed new rule for each year of the first five years that it will be in effect, as well as the analysis required by Texas Government Code, §2006.002. That statute requires that, before adopting a rule that may have an adverse economic effect on small businesses or micro-businesses, a state agency prepare an economic impact statement and a regulatory flexibility analysis. The economic impact statement must estimate the number of small businesses or micro-businesses subject to the proposed rule, project the economic impact of the rule on small businesses and micro-businesses, and describe alternative methods of achieving the purpose of the proposed rule. A regulatory flexibility analysis must include the agency's consideration of alternative methods of achieving the purpose of the proposed rule. The analysis must consider: if consistent with the health, safety, and environmental and economic welfare of the state, using regulatory methods that will accomplish the objectives of applicable rules while minimizing adverse impacts on small businesses and micro-businesses. The state agency must include in the analysis several proposed methods of reducing the adverse impact of a proposed rule on a small business or a micro-business. The statute defines “small business” as a legal entity, including a corporation, partnership, or sole proprietorship, that is formed for the purpose of making a profit; is independently owned and operated; and has fewer than 100 employees or less than $6 million in annual gross receipts. A “micro-business‘ is defined as a legal entity, including a corporation, partnership, or sole proprietorship, that is formed for the purpose of making a profit; is independently owned and operated; and has no more than 20 employees.

The Commission has determined that any increased cost of compliance for entities filing an organization report (“operators”), regardless of status as a small business or micro-business, will be incurred only if the operator is in violation of Railroad Commission rules, and therefore can be viewed an avoidable cost. Based on the information available to the Commission regarding the entities that file organization reports, Mr. Fernandez concludes that it is extremely likely that a business that potentially could be affected by the proposed rule would be classified as a small business or micro-business, as those terms are defined in Texas Government Code, §2006.001. The North American Industrial Classification System (NAICS) sets forth categories of business types. Operators of oil and gas activities fall within the category for crude petroleum and natural gas extraction. This category is listed on the Texas Comptroller of Public Accounts website page entitled "HB 3430 Reporting Requirements-Determining Potential Effects on Small Businesses" as business type 2111 (Oil & Gas Extraction), for which there are listed 2,784 companies in Texas. This source further indicates that 2,582 companies (92.7 percent) are small businesses or micro-businesses, as those terms are defined in Texas Government Code, §2006.001.

The Commission has also determined that a regulatory flexibility analysis is not required because an operator will incur costs for administrative penalties only if the operator violates Commission rules, and therefore the penalty amounts can be viewed as an avoidable cost. Further, the Commission has determined that administering the statutory provisions related to penalties for violations of Texas Natural Resources Code, Chapter 113, and the Commission's oil and gas rules, requires that the penalty amounts imposed be punitive. Minimizing the adverse impacts on small businesses and micro-businesses of administrative penalties assessed for violations of the statute or Commission rules is not consistent with ensuring the health, safety, and environmental and economic welfare of the state.

The Commission finds that the proposed new rule likely would not affect a local economy. Therefore, the Commission has not prepared a local employment impact statement pursuant to Texas Government Code, §2002.022.

The Commission has determined that the proposed new rule is not a major environmental rule, because the rule does not meet the requirements set forth in Texas Government Code, §2001.0225(a). The proposed rule does not exceed the express requirements of state law, and is not being adopted solely under the general powers of the agency.

Comments on the proposal may be submitted to Rules Coordinator, Office of General Counsel, Railroad Commission of Texas, P.O. Box 12967, Austin, Texas 78711-2967; online at www.rrc.state.tx.us/rules/commentform.php; or by electronic mail to rulescoordinator@rrc.state.tx.us. The Commission will accept comments until 12:00 p.m. (noon) on Monday, March 12, 2012, which is 31 days after publication in the _Texas Register._ The Commission finds that this comment period is reasonable because the proposal as well as an online comment form will be available on the Commission's web site no later than the day after the open meeting at which the Commission approves publication of the proposal, giving interested persons over two additional weeks to review, analyze, draft, and submit comments. Comments should refer to Oil and Gas Docket No. 20-0274145. The Commission encourages all interested persons to submit comments no later than the deadline. The Commission cannot guarantee that comments submitted after the deadline will be considered. For further information, call Mr. Fernandez at (512) 463-6827. The status of Commission rulemakings in progress is available at www.rrc.state.tx.us/rules/proposed.php.

The Commission proposes the new rule pursuant to Texas Natural Resources Code, §81.051 and §81.052, which give the Commission jurisdiction over all persons owning or engaged in drilling or operating oil or gas wells in Texas and the authority to adopt all necessary rules for governing and regulating persons and their operations under the jurisdiction of the Commission; and Texas Natural Resources Code, §81.0531, which gives the Commission authority to assess a penalty if a person violates provisions of Texas Natural Resources Code, Title 3, that pertain to safety or the prevention or control of pollution or the provisions of a rule, order, license, permit, or certificate that pertain to safety or the prevention or control of pollution that are issued under Title 3.

Texas Natural Resources Code, §§81.051, 81.052, and 81.0531, are affected by the proposed new rule.

Statutory authority: Texas Natural Resources Code, §§81.051, 81.052, and 81.0531.

Cross-reference to statute: Texas Natural Resources Code, §§81.051, 81.052, and 81.0531.

Issued in Austin, Texas on January 24, 2012.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

Filed with the Office of the Secretary of State on January 24, 2012.

TRD-201200314

Mary Ross McDonald

Director, Pipeline Safety Division

Railroad Commission of Texas

Earliest possible date of adoption: March 11, 2012

For further information, please call: (512) 475-1295

End of Document

Exhibit 24.01

This exhibit was not previously submitted in November 2023

Water Usage in the Permian Basin: Drilling and Fracturing without Fresh Water

AAPG Global Super Basin Conference – The Permian

January 23rd - 24th, 2019

Stonnie L. Pollock, Senior Geologist, Fasken Oil and Ranch

FASKEN OIL AND RANCH

Fee BN Treatment Frac Pits – 800,000 bbls per pit

FASKEN OIL AND RANCH

Exhibit 24.02

This exhibit was not previously submitted in November 2023

Public Health Dimensions of Upstream Oil and Gas Development in California: Scientific Analysis and Synthesis to Inform Science-Policy Decision Making

June 21, 2024

California Oil & Gas Public Health Rulemaking Scientific Advisory Panel

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**Served as an Expert Panel Member until February 3, 2023*

***Served as an Expert Panel Member until May 18, 2023*

****Served as an Expert Panel member until August 6, 2021*

*****Served as an Expert Panel Member until July 5, 2021*

Acknowledgements

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Public Health Dimensions of Upstream Oil and Gas Development in California: Scientific Analysis and Synthesis to Inform Science-Policy Decision Making

Table of Contents – Full Report

EXECUTIVE SUMMARY

Findings, Conclusions, and Recommendations

The primary role of the California Oil and Gas Public Health Rulemaking Scientific Advisory Panel ("Panel") is to provide subject matter expertise to the California Geologic Energy Management Division (CalGEM) to inform the agency's rulemaking process. The specific charge of the Panel is to evaluate and synthesize the best available peer-reviewed science and publicly available data on the public-health dimensions of upstream oil and gas development in order to draw well-informed findings, conclusions, and recommendations. The Panel reached consensus regarding all findings, conclusions, and recommendations in this report.[1]

In developing recommendations, the Panel was guided by the principle of "defense in depth," for which the deployment of multiple independent, yet redundant factors of safety is seen as a fundamental strategy to safeguard public health. This principle has been widely adopted across industries and issue areas.[2,3] Implementation of multiple preventative or attenuation strategies is necessary to mitigate public-health risks associated with upstream oil and gas development in California.[4] The concept of defense in depth is particularly important with respect to the management of off-normal events that cannot be immediately controlled.

Findings, conclusions, and recommendations from this report follow below. *Findings* are results ascertained from scientific evidence and data and reflect an unbiased synthesis of facts. Findings are included with direct references to supporting material in corresponding chapters of this report. *Conclusions* are panel-consensus deductions based on the *findings*. *Recommendations* are statements of actions needed to address the *findings* and *conclusions*.

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[1] Consensus means that all Panel members reviewed the findings, conclusions, and recommendations and affirmatively agreed that the scientific evidence supports them. Panel members had the opportunity to prepare a dissenting assessment, but no one did so. This report reflects the perspective of the Panel members and not necessarily those of their employers or the institutions with which they are affiliated.

[2] International Nuclear Safety Advisory Group. (1996). *Defense in Depth in Nuclear Safety: A Report by the International Nuclear Safety Advisory Group (INSAG-10)*. International Atomic Energy Agency.

[3] U.S. NRC (United States Nuclear Regulatory Commission). (2021). *Defense in depth*.

[4] Deziel, N. C., McKenzie, L. M., Casey, J. A., McKone, T. E., Johnston, J. E., Gonzalez, D. J. X., Shonkoff, S. B. C., & Morello-Frosch, R. (2022). Applying the hierarchy of controls to oil and gas development. *Environmental Research Letters*, *17*(7), 071003. https://doi.org/10.1088/1748-9326/ac7967

SUMMARY FINDING 1.

As the distance between human-occupied residences and upstream oil and gas development operations decreases, or the density of wells and production volume increases, the likelihood of adverse health outcomes increases. Studies, including those in California, consistently show increased potential for exposure to air pollution and noise, as well as increased risk for several adverse health outcomes in populations living within and beyond 1 kilometer (km) (~0.62 miles or 3,281 feet [ft]) of oil and gas well sites. Certain groups face disproportionate exposures to oil and gas development sites. Compared to the overall California population, Hispanic, non-Hispanic Black, and non-Hispanic Asian communities, as well as populations of lower socioeconomic status, are more likely to live within 1 km (3,281 ft) of at least one active well and live in areas with the highest density of oil and gas wells.[5]

Finding 1.1. Various chemical and physical stressors are associated with upstream oil and gas development activities, including air pollutants, surface-water and groundwater contaminants, vibration, noise, and odors. The impact of these stressors generally attenuates as distance from the source increases. The degree of attenuation depends on the properties of the specific stressor *(Chapter 2, Section 2.4)*.

Finding 1.2. Although no peer-reviewed noise studies related to upstream oil and gas development activities have been conducted in California, studies elsewhere have measured elevated noise levels during all oil and gas development phases at levels associated with adverse health effects out to 1,000 ft [305 meters (m)] from multi-well oil and gas sites, even with sound walls in place *(Chapter 2, Section 2.3.1).*

Finding 1.3. More than 72 peer-reviewed epidemiological studies conducted across the United States and Canada — six conducted in California — and published through July 15, 2023, evaluated the associations between upstream oil and gas development and several adverse health outcomes. This body of evidence consistently indicates that human populations residing *closer* to upstream oil and gas development experience a greater risk of decreased respiratory function and adverse perinatal outcomes compared to those living farther away (*Chapter 3, Section 3.3.2.1*). Additionally, higher *density* of upstream oil and gas development in the vicinity of residences is associated with greater respiratory and perinatal health risks compared to lower density of oil and gas development. Finally, higher *production volume of oil and gas* is associated with increased risk of adverse respiratory and perinatal health impacts. These trends have

[5] This section contains language about the panel's level of certainty regarding the results reported in the epidemiologic literature. This language only appears in the epidemiology section as the panel conducted a full review of the literature and is therefore able to make this designation.

been observed in urban and rural settings *(Chapter 3, Section 3.5).* For other health outcomes, including cancer, cardiovascular disease, sexually transmitted infections, and mental and behavioral health, there are limited studies and more research is needed to evaluate the consistency of relationships (*Chapter 3, Sections 3.3.2.4–3.3.2.7; Appendix C*). Strengths and limitations vary by study and are discussed in *Chapter 3, Section 3.4.1*.

Finding 1.4. The Panel identified six peer-reviewed epidemiological studies in California that evaluated associations between upstream oil and gas development and adverse respiratory, perinatal, and neurological outcomes. These studies observed associations between upstream oil and gas development and diagnosed asthma, reduced lung function, and reduced fetal growth at distances of up to 1 km (~0.62 miles or 3,281 ft). Studies in California evaluating the relationship between upstream oil and gas development and risk of preterm birth reported inconsistent results. One California study did not observe an association between upstream oil and gas development and migraine headaches *(Chapter 3, Section 3.5)*.

Finding 1.5. Air-quality research in California has found above-background-level concentrations of non-methane volatile organic compounds (NMVOCs), toxic air contaminants (TACs), and ozone precursors near upstream oil and gas development sites. For each additional well drilling site upwind of U.S. Environmental Protection Agency (EPA) air quality monitors, the concentrations of fine particulate matter ($PM_{2.5}$) increased by 2.35 (standard error [SE]: 0.78) µg/m^3 (micrograms per cubic meter) for wells within 2 km (6,562 ft); ozone (O_3) by 0.31 (SE: 0.06) parts per billion (ppb) for wells within 2–3 km (6,562–9,843 ft); and nitrogen dioxide (NO_2) by 2.27 (SE: 1.40) ppb for wells within 1 km (3,281 ft). For each additional active well upwind of the monitor, these authors also found 1.93 (SE: 0.43) µg/m^3 of $PM_{2.5}$, 0.62 (SE: 0.12) ppb of NO_2, and 0.04 (SE: 0.02) ppb carbon (C) of NMVOCs. These models compared monitors to themselves on days when there was and was not drilling or production activities upwind, and also controlled for time trends and geographic differences. In a study in Los Angeles, concentrations of TACs, such as benzene and n-hexane, were elevated at 0.5 km (1,640 ft) from upstream oil and gas sites, the farthest distance evaluated. Methane, which can sometimes be used to indicate the presence of other oil and gas-related air pollutants, was also measured at concentrations above background. Oil and gas production facilities have periods of active production as well as idle periods, such that emissions from wells greatly differ depending on the phase. Findings from this study suggest that oil and gas drilling during the active phase contributed 23.7% of the total NMVOCs measured, while the idle period only contributed 0.6% (*Chapter 4, Section 4.2.2*).

Finding 1.6. An estimated 3 million California residents (8% of the population) live within 1 km (3,281 ft) of at least one active-producing[6] oil and/or gas well. Based on satellite imagery, an estimated 670,000 residentially zoned buildings, or 6% of all California buildings, are within 1 km (3,281 ft) of at least one active-producing well. Many sensitive receptors, defined as schools (pre-K to 12th grade), childcare facilities, healthcare facilities, senior care facilities, correctional facilities, parks, and residential buildings, are also located in close proximity to oil and gas development in California *(Chapter 7, Sections 7.4 & 7.6; see Table ES-1 below)*.

Finding 1.7. A relatively small proportion of active producing oil and gas wells in California have a school, childcare facility, healthcare facility, senior care facility, correctional facility, or park within 1 km (3,281 ft). For example, an estimated 6,006 active-producing wells (7.2% of all wells) are within 1 km (3,281 ft) of at least one school. Similarly, 2,377 wells (~3% of all wells) are responsible for all of the co-location with healthcare facilities at the 1 km (3,281 ft) distance. Over 30,000 (36%) active-producing wells, however, are located within 1 km (3,281 ft) of residential buildings in California *(Chapter 7, Section 7.4.3)*.

Finding 1.8. An estimated 1,663 (2%) active-producing wells are within 100 ft (30 m) of at least one home (n=3,661 homes). California State Fire Code regulation *§ 5706.3* prohibits location of oil and gas wells within 100 ft (30 m) of any building not necessary to the operation of the well, however, local jurisdictions may amend the regulation *(Chapter 7, Section 7.4.5).*

[6] Active-producing oil or gas wells were defined as *active* if reported as active, new, or idle and *producing*; i.e., a well that was part of a class where at least 1% of wells of that type produced hydrocarbons, indicating that the well was capable of producing.

Table ES-1. Residents and sensitive receptors in proximity to at least one of the 83,000 active-producing oil and gas wells in California, January 2021. For purposes of this report, sensitive receptors include schools (pre-K to 12th grade), childcare facilities, healthcare facilities, senior care facilities, correctional facilities, parks, and residential buildings.

Buffer Distance	Number of Residents	Under 5 years old	Over 64 years old	Schools (pre-K to 12th grade)	Child-care Facilities	Health-care Facilities	Senior care Facilities	Correct-ional Facilities	Parks	Residential Buildings
Statewide Total	**38,984,806**	**2,698,315**	**5,352,812**	**22,452**	**8,867**	**2,131**	**7,246**	**408**	**4,983**	**12,577,497**
500 ft (152 m)	219,681	15,110	30,959	226	68	25	44	7	90	44,994
1,000 ft (305 m)	590,116	39,476	82,984	439	122	59	118	9	154	123,167
1,500 ft (457 m)	1,032,255	68,909	143,807	668	218	87	176	15	208	221,262
2,000 ft (610 m)	1,551,743	103,736	212,905	990	336	116	237	18	276	334,816
2,500 ft (762 m)	2,123,961	141,733	287,705	1,293	451	156	324	21	344	461,246
3,281 ft (1 km)	3,080,713	205,027	412,674	1,749	659	207	466	28	461	673,068
5,280 ft (1.6 km; 1 mile)	5,772,699	384,810	760,877	3,245	1,262	364	832	55	841	1,260,567

Finding 1.9. The statewide analysis of parcel and census data (2015–2019 American Community Survey) shows that the proportions of Hispanic, non-Hispanic Black, and non-Hispanic Asian people, linguistically isolated households, renters, individuals without a high school diploma, and populations with household incomes below two times the federal poverty line were higher in areas within 1 km (3,281 ft) of at least one active-producing well compared to the overall proportion of each of these groups in California (*see Figure ES-1 below*).

Additionally, compared to non-Hispanic White Californians, non-Hispanic Black Californians are 87% more likely to reside within 1 km (3,281 ft) of at least one active-producing oil and gas well. Similarly, the proportion of Hispanic Californians living within 1 km (3,281 ft) of at least one active-producing oil and gas well is 42% higher than non-Hispanic White people.

Findings indicate that compared to non-Hispanic White and more socioeconomically advantaged populations, non-Hispanic Black, non-Hispanic Asian, and Hispanic populations and those of lower socioeconomic status were more likely to live near upstream oil and gas development activities where exposures to stressors are likely to be higher *(Chapter 7, Section 7.4.1)*.

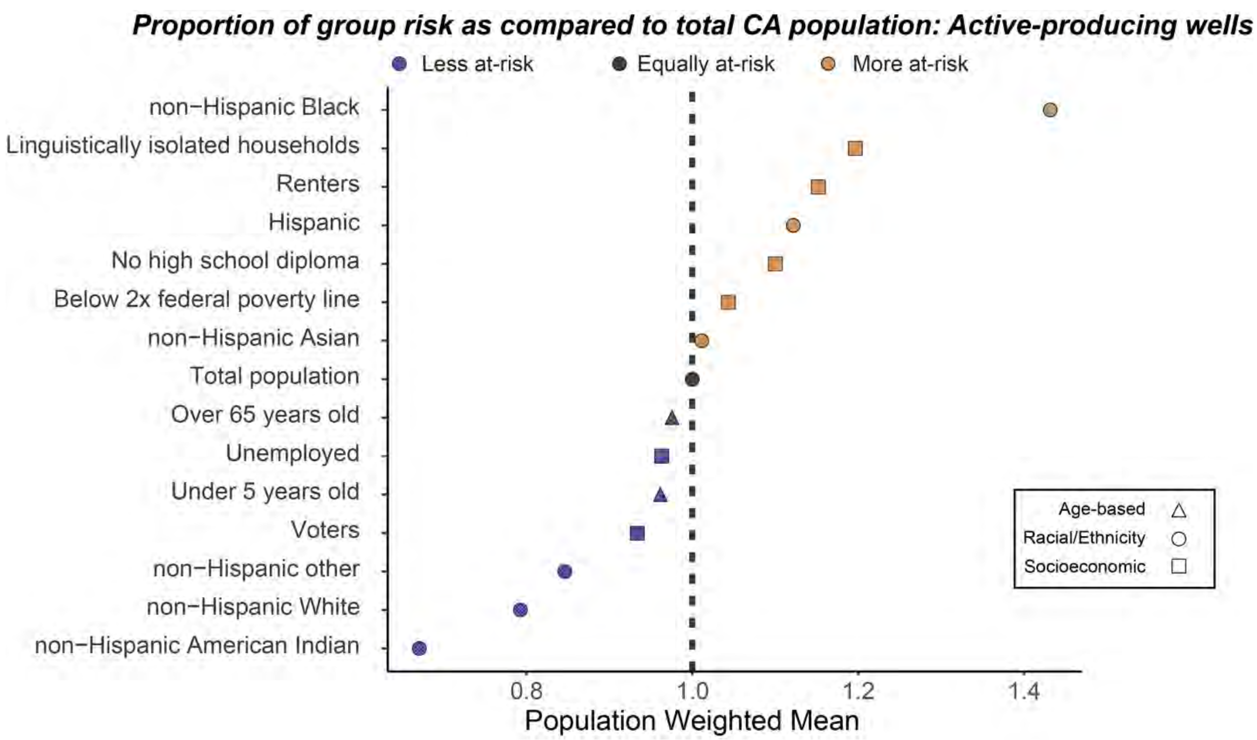

Figure ES-1. Distributional inequities of demographic groups living within 1 km (3,281 ft) of active-producing oil and gas wells as compared to state population totals. Orange markers indicate a population-weighted mean greater than one, indicating a level of subgroup overrepresentation in areas that contain upstream oil and gas development within 1 km (3,281 ft). Blue markers indicate a level of subgroup underrepresentation in areas that contain upstream oil and gas development within 1 km (3,281 ft).

Finding 1.10. Among California's 8,057 census tracts, 157 (1.9%) contained 10 or more wells per square km (0.39 square mi). Sixty-four of these 157 census tracts (~41%) have a CalEnviroScreen 3.0[7] score that designates them as a disadvantaged community with disproportionate socioeconomic, health, and environmental burdens, in addition to the burdens associated with upstream oil and gas development. Because a quarter of all California census tracts are designated as disadvantaged communities based on CalEnviroScreen scores, this finding indicates that disadvantaged communities are overrepresented (1.6 times more common) in census tracts that contain 10 or more wells per square km (0.39 square mi) *(Chapter 7, Section 7.4.4).*

Finding 1.11. 95% of California's active-producing wells are spatially clustered in three air basins. Spatial clustering or high well density suggests that proximity to one well likely means proximity to many wells. For example, 21 healthcare facilities have more than 100 active-producing wells within 1 km (3,281 ft), and 14 facilities have more than 200. Similarly, 107 schools have over 100 wells within 1 km (3,281 ft) (and 33 of these schools have over 300 wells within 1 km (3,281 ft) *(Chapter 7, Section 7.4.3)*.

Finding 1.12. An estimated 400,000 — or roughly 1 in 100 (1%) — California residents live within 1 km (3,281 ft) of an active produced-water disposal pond and wells designated as "Water Disposal" in CalGEM's "All Wells" dataset.[8] Within this distance are an estimated 98,700 residentially-zoned buildings, 239 schools (pre-K to 12th grade), 91 senior care facilities, and 26 healthcare facilities. Emissions of NMVOCs have been measured from produced-water ponds in California; however, the distances that these compounds travel and their corresponding atmospheric concentrations have not been assessed. Moreover, publicly available data with accurate drinking-water well spatial locations in California have not been available. This hinders the ability to evaluate the risk of drinking water contamination from subsurface migration of fluids from produced water disposal processes *(Chapter 7, Section 7.4.2 & 7.4.3)*.

Finding 1.13. Setback regulations in several states have exemption and conditional exception mechanisms that allow operators to apply for variances and drill oil and gas wells within regulated setback distances. In some Texas cities, variances have resulted in 80% of new well pads being located within regulated setback distances. Largely due to variances and landowner consent, the passage of a strengthened setback regulation in Pennsylvania did not alter the siting of wells near buildings. One out of every 13.7 unconventional oil and gas wells was drilled within the regulated setback distance after passage of the regulation *(Chapter 7, Section 7.2.5)*.

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[7] CalEnviroScreen 3.0. https://oehha.ca.gov/calenviroscreen/report/calenviroscreen-30

[8] Wells designated as "Water Disposal" in CalGEM's "All Wells" dataset. https://www.conservation.ca.gov/calgem/maps.

Conclusion 1.1. Exposure to upstream oil and gas development is associated with a range of adverse health effects. In particular, the Panel concludes with a high level of certainty (*see Box 1*) that there is a causal relationship between close residential proximity to upstream oil and gas development and adverse perinatal and respiratory outcomes. The Panel derived this level of certainty from the consistency of results across multiple studies that were conducted using different methodologies, in different locations, with diverse populations, and during different time periods. In California, epidemiological studies have shown statistically significant[9] associations between upstream oil and gas development and adverse health outcomes at distances of 1 km (3,281 ft) and beyond. Epidemiological studies conducted in other oil and gas regions in the United States and Canada have also consistently shown statistically significant associations between upstream oil and gas development and adverse health outcomes within and beyond 1 km (3,281 ft).

<u>Box 1.</u>
The Panel applied the Bradford Hill Criteria for causation *(see Chapter 3, Section 3.3.2.1)* to evaluate the strength of the epidemiological evidence for determining a causal relationship between oil and gas development and adverse human health outcomes. The Bradford Hill criteria are widely used in the field of epidemiology to assess the strength of evidence to assess causality. Where the Bradford Hill Criteria supported a causal relationship and where there was Panel agreement, the Panel concluded with a high level of certainty that there is a causal relationship. The Panel applied these criteria to draw conclusions on whether causal relationships exist between geographic proximity to oil and gas development activities and adverse health outcomes.

Conclusion 1.2. The human health risks associated with chemical and physical stressors emitted by upstream oil and gas sites (air and water pollutants, noise, etc.) can be reduced by establishing greater setback distances between upstream oil and gas development and sensitive receptors, whether it be a human receptor or a receptor

[9] Individual studies often define statistical significance as a p-value that is less than 0.05 or a confidence interval that does not include the null (e.g., 1). However, weight-of-evidence assessments regarding causal relationships between exposures and health outcomes require a holistic assessment of the epidemiological evidence (e.g., by applying the Bradford Hill criteria, as discussed in *Box 1 below* and in *Chapter 3*), and considering size, consistency, and direction of effect, rather than relying solely on dichotomous determinations of statistical significance in individual studies.

relevant to human exposure (e.g., an aquifer that is currently used or in the future could be used for drinking water).

Conclusion 1.3. The human health risks associated with chemical and physical stressors emitted by upstream oil and gas development can be reduced by lowering the density of oil and gas sites around human receptors or receptors relevant to human exposure (e.g., an aquifer that is currently used or in the future could be used for drinking water).

Conclusion 1.4. The 1,663 active-producing wells in California located within 100 ft (30 m) of residential buildings are out of compliance with California State Fire Code regulation *§ 5706.3,* unless they have an exemption, potentially exposing people in these buildings to increased health and safety risks.

Conclusion 1.5. Upstream oil and gas development operations in California are disproportionately located in disadvantaged communities. Disadvantaged communities may be more vulnerable to the adverse health effects of oil and gas development due to concurrent exposures to other environmental hazards and social stressors.

Conclusion 1.6. Exemptions, variances, and consent waivers to setback regulations can weaken well-siting requirements and diminish the public health protections for communities and other sensitive receptors.

Recommendation 1.1. *Implement a health-protective minimum surface setback.* Implementing minimum surface setbacks between upstream oil and gas operations and human receptors is critical to protect public health. To mitigate health risks associated with upstream oil and gas development, California should implement a health-protective, minimum surface setback distance between upstream oil and gas development and human populations. Based on the existing epidemiological literature, including studies conducted in California, and the additional factors outlined below, the setback distance should be at least 1 km (3,281 ft). In communities with higher well density, high hydrocarbon production volumes, dense ancillary oil and gas development infrastructure, and the presence of other environmental hazards and socioeconomic stressors, a larger setback should be applied.

Decision-making regarding the appropriate health-protective minimum surface setback distance should consider the following:

- **Multiple stressors associated with upstream oil and gas development** (e.g., noise, odor, vibration, air pollution, water pollution), rather than solely mitigating health and safety impacts of an individual stressor (e.g., only air pollution).
- **Inclusion of an additional margin of safety** to account for the vulnerabilities of particular population subgroups (e.g., children, pregnant people, those with

chronic illnesses, and the elderly) and given the potential for off-normal events (e.g., blowouts, loss of containment events, and accidental releases) that cannot be immediately controlled or consistently prevented. Decisions on a health-protective minimum surface setback distance should be made with particular attention to the locations of sensitive receptors, including but not limited to schools (pre-K to 12th grade), childcare facilities, healthcare facilities, senior care facilities, correctional facilities, parks, and residential buildings.
- **Existing environmental and socioeconomic burdens experienced by communities that may enhance vulnerability to the adverse health effects of oil and gas development activities**. Upstream oil and gas siting decisions and setback requirements should be informed by and account for data-driven metrics used to assess the cumulative burden of communities (e.g., CalEnviroScreen) to ensure that the additional burden associated with upstream oil and gas development is not placed on disadvantaged communities.
- **Because exemptions and conditional exceptions for minimum surface setback requirements will likely diminish health protections for communities and other sensitive receptors, such exemptions and exceptions should be avoided.**

Recommendation 1.2. Limit the density of wells and associated infrastructure, especially near human populations. The weight of the scientific evidence indicates that the risk of adverse health outcomes (e.g., adverse perinatal outcomes, and respiratory outcomes) increases with higher oil and gas well density and hydrocarbon production volume. Thus, in addition to setback requirements, decision-makers should also consider the following:

- Limit upstream oil and gas development in areas with existing oil and gas wells near human populations. Such measures could include rotating temporary well shut-ins and ancillary infrastructure site shut downs, and establishing production volume limits within a certain distance of human populations.
- Require closure and proper abandonment of existing oil and gas operations within 100 ft (30 m) of residential buildings, in particular those that are not exempt from California State Fire Code regulation *§ 5706.3*.
- Review the status and regulatory compliance of all oil and gas operations located within 100 ft (30 m) of residential buildings.

SUMMARY FINDING 2.

There are limited publicly available data on the chemical composition, rates, and amounts of air pollutant emissions from upstream oil and gas development infrastructure. These types of data are necessary to properly assess pollutant

dispersion and community exposures and to respond to air pollution impacts from normal and off-normal release events.

Finding 2.1. There are limited publicly available data on the chemical composition of gases emitted from upstream oil and gas development. These gases include, but are not limited to, natural gas and vapors (gaseous form of volatilized liquids). The sources of these gases include, but are not limited to, the production string of wells; condensate tanks; gas-gathering infrastructure; gas-processing plants; idle, abandoned, and idle-deserted oil and gas wells; and other ancillary infrastructure. *(Chapter 4, Section 4.2.1).*

Conclusion 2.1. Effective risk management of normal and off-normal conditions in upstream oil- and gas-development infrastructure requires timely, accurate, and publicly available data on the chemical composition of emissions from oil and gas infrastructure. The limitations in existing data hinder the ability of regulators, risk managers, and researchers to track emissions and assess pollutant dispersion, community exposures, and risks to human health associated with California's upstream oil and gas development.

Recommendation 2.1. Require regular sampling and reporting of the composition of gas releases from upstream oil and gas development, hydrocarbon storage, and associated infrastructure including, but not limited to, the gas in the production string of wells; gas pre- and post-glycol dehydration, gases and vapors in condensate tanks; gas in gas-gathering lines and associated infrastructure; gas in gas-processing plants; and gas in idle, abandoned, and idle-deserted oil and gas wells. Reported gas composition data should include adequate characterization of the identities, concentrations, and amounts of toxic air contaminants at health-relevant units (e.g., the part per billion (ppb) level) and should be based on actual gas testing (e.g., EPA Method TO-15) instead of algorithms, estimates, or emissions factors. Because of the substantial variability of gas composition across geological layers, operators should be required to disclose production-string gas composition down to the oil and/or gas producing formations within individual oil and gas fields or the oil/gas geologic pool-level, whichever is smaller. Gas composition data from active infrastructure should be reported at regular intervals, preferably quarterly, and be made publicly available online in a digitally accessible format (e.g., .csv with metadata). Gas composition data from legacy infrastructure (e.g., abandoned wells) should also be reported at regular intervals, up to once a year. Pollutant dispersion and exposure information should also be collected to support an analysis of public health risk.

SUMMARY FINDING 3.

There are multiple and differing disclosure requirements across a range of California jurisdictions. While public disclosure requirements for chemicals used

in oil and gas development in California have increased, publicly available data on the identities and quantities of chemicals used in various oil and gas development activities remain incomplete. These activities include routine well maintenance and clean-outs, drilling, and well stimulation. Many of the chemicals known to be used in oil and gas development activities are associated with human health risks, while numerous other reported chemicals have unknown or poorly understood toxicity.

Finding 3.1. Chemical use in upstream oil and gas development is widespread and not restricted to hydraulic fracturing and well stimulation. As discussed in the California Council on Science and Technology (CCST) Senate Bill 1281 Report,[10] 630 unique chemical additives were used in upstream oil and gas operations in California from 2011 to 2018 with an additional 489 chemicals that lacked Chemical Abstract Service Registry Numbers (CASRN) and could not be definitively identified. Many disclosed chemicals lack basic toxicological and physicochemical-properties information *(Chapter 2, Section 2.2.4)*.

Finding 3.2. An analysis of four existing chemical disclosure datasets representing various well activities and geographic regions in California revealed overlap of chemicals. For 630 chemicals with CASRN, 316 were reported in more than one dataset, with 178 chemicals reported in three or more datasets. The overlap in reported chemical use across well activities indicates that the use of chemicals is widespread in California oil and gas development and is not limited to a particular region, well activity, or recovery method (*Chapter 2, Section 2.2.4*).

Finding 3.3. Federal regulations and regulations in other states have prohibited the use of specific chemical additives in hydraulic fracturing. Effective January 15, 2021, the Colorado Code of Regulations (*§ 404-1-437)* prohibits the use of 22 specific compounds in hydraulic fracturing fluids because these compounds posed the greatest risks to public health based on toxicity and their mobility and persistence in groundwater *(Chapter 2, Section 2.5.2)*.

Finding 3.4. Downhole physicochemical conditions, including high temperatures and pressures and the presence of petroleum hydrocarbons and other compounds, can alter biodegradation potentials, subsurface reactions, and degradation products. The formation of degradation products from chemicals used in upstream oil and gas development is poorly understood, but the subsurface reactions of some chemicals used

[10] California Council on Science and Technology. (2019). *An Assessment of Oil and Gas Water Cycle Reporting in California: Evaluation of Data Collected Pursuant to California Senate Bill 1281*. https://ccst.us/reports/oil-and-gas-water-cycle-reporting/.

in California oilfields are known to produce degradation products that are more toxic than their parent compounds *(Chapter 5, Section 5.3.3)*.

Finding 3.5. A total of 232 chemical additives (out of 630) reportedly used in California oilfields are volatile and pose potential risks to air quality and human health. Out of these 232 volatile compounds, 176 have slow to moderate atmospheric oxidation rates (half-lives >2 hours), indicating increased potential for longer-range atmospheric transport and subsequent inhalation exposure *(Chapter 4, Appendix D)*.

Conclusion 3.1. Available toxicological and physicochemical data suggest there are potential human health risks associated with chemical use in upstream oil and gas development. Data gaps regarding chemical mass or volumes used, toxicity, physicochemical properties, and environmental fate and transport prevent the characterization of hazards and risks for many disclosed chemical additives. Chemical additives without CASRN cannot be definitively identified or evaluated for potential human health hazards and impacts.

Conclusion 3.2. Existing data show that a variety of chemicals are used in upstream oil and gas development across regions, recovery methods, and well activities. Current regulations concerning chemical disclosure or the prohibition of chemical additives that apply only to specific recovery methods (i.e., hydraulic fracturing and well stimulation) overlook potential risks related to chemical use in drilling, routine maintenance, and other recovery methods and well activities.

Conclusion 3.3. Collection and public reporting of chemical usage, along with chemical properties and toxicity data, are required to properly assess and respond to potential chemical releases to air and water.

Recommendation 3.1. Require chemical disclosure and community notifications for chemical additives (including mixtures) added to fluids used for well drilling, treatment, rework, and maintenance operations in all upstream oil and gas operations, not just for well stimulation and activities where produced water is discharged to the surface. CASRN, mass, concentration, and volume data should be required for all chemical disclosures, including proprietary chemicals. Timing of chemical use should also be reported. These chemical disclosures should be made publicly available in a digital format. It is important to have consistent disclosure requirements across all oil and gas development in California.

Recommendation 3.2. Fully disclose and restrict the use of chemical additives in upstream oil and gas development with the greatest risks to public health based on toxicity and their mobility and persistence in groundwater, and implement green-chemistry principles to replace these additives and poorly characterized chemicals with less-hazardous compounds. Colorado House Bill 1348, signed by Colorado Governor Polis in June 2022, provides a model for implementing disclosure requirements for any chemical that may be used in oil and gas production to enable the public and regulators to evaluate the environmental and public health impacts of these chemicals and to encourage less-toxic alternatives. This bill also includes explicit restrictions on the use of per- and polyfluoroalkyl substances (PFAS).

Recommendation 3.3. Comprehensive toxicological, environmental, and physico-chemical profiles should be developed for chemicals used in upstream oil and gas development that are missing key data needed to determine human health hazards and for risk assessment. Prioritization of chemicals for review should be based on usage frequency, mass used, and the potential for human and environmental exposure. Given the complexity of prioritizing chemicals with limited information, agencies should consider enlisting independent subject-matter experts to help conduct this task.

SUMMARY FINDING 4.

Upstream oil and gas development is associated with emissions of volatile organic compounds (VOCs). These VOCs include both greenhouse gases and toxic air contaminants, including methane and non-methane VOCs (NMVOCs). Exemptions for emission control and leak detection and repair (LDAR) requirements exist for heavy oil development facilities and for small producers across California. The justification for these exemptions is based in part on the assumption that methane emissions from these operations represent a small fraction of the total *methane* emissions from all upstream oil and gas development in California. While methane can be a reasonable indicator for NMVOCs when the source is methane-rich (e.g., natural gas processing plants, natural gas gathering infrastructure, etc.), methane is not a reliable indicator for NMVOCs when the source is not methane-rich (e.g., condensate tanks, heavy oil flashing, and produced water management and disposal). Methane cannot be used as the sole indicator for NMVOC emissions from sources that do not emit methane (e.g., diesel engines and other combustion sources) or emissions of criteria of air pollutants such as particulate matter and nitrogen oxides.

Finding 4.1. Methane and NMVOCs are emitted during upstream oil and gas development. Many of the NMVOCs emitted are toxic air contaminants or ground-level ozone precursors. Because both methane and some NMVOCs have a common source, certain infrastructure components, such as wellheads, gas pipelines, and gas processing plants, have emission profiles with high methane/non-methane hydrocarbon (NMHC) ratios. However, other components, such as condensate tanks and produced water ponds, have emission profiles with far lower methane/non-methane hydrocarbon ratios, and methane is not a reliable indicator of NMVOCs that are not hydrocarbons. While diesel engines used for transport, pumps and other purposes do not emit methane and have a zero methane:NMHC ratio, they do emit criteria air pollutants (CAPs), toxic air contaminants, and other air pollutants *(Chapter 4, Sections 4.2.1 and 4.4.1)*.

Finding 4.2. Studies conducted on oil and gas development outside of California identified several NMVOCs, including toxic air contaminants such as n-hexane, benzene, ethylbenzene, toluene, and xylenes, as methane co-pollutants. Significant correlations were also found among emissions of benzene and toluene, benzene and m- & p-xylene, and toluene and m- & p-xylene. Many of the NMVOCs identified as methane co-pollutants in other oil- and gas-producing states have been detected in emissions from, and atmospheric concentrations near, upstream oil and gas development in California (e.g., benzene, toluene, ethylbenzene, xylenes, and alkanes) *(Chapter 4, Sections 4.2.1; 4.4.1; and 4.5)*.

Finding 4.3. In California, regulatory exemptions from vapor recovery, LDAR, and equipment change-out requirements have been established based on methane and NMVOC emissions from specific upstream oil and gas sources. These exemptions include, but are not limited to (1) a statewide zero-bleed/zero-emission standards exemption for existing low bleed (<6 standard cubic feet per hour) natural-gas driven pneumatic devices installed prior to January 1, 2016, (2) an exemption from the statewide 95% vapor recovery requirement for low-throughput separators and condensate tank systems, and (3) an exemption from the statewide LDAR requirement for upstream oil and gas infrastructure components associated with heavy oil (API gravity <20) *(Chapter 4, Section 4.4)*.

Finding 4.4. The closure of the exemptions from statewide zero-bleed/zero-emission standards for existing low-bleed pneumatic devices and vapor recovery requirements for low-throughput separators and condensate tank systems listed in Finding 4.3 would reduce NMVOC emissions by an estimated 15 tons per year (tpy) from 50 existing natural gas powered pneumatic devices and 208 tpy from ~2,200 small throughput separator and tank systems. Additionally, the California Air Resources Board states that heavy oil components (API gravity <20) exempt from LDAR account for less than 1% of hydrocarbon emissions from leaking components *(Chapter 4, Section 4.4)*.

Conclusion 4.1. While exemptions discussed in Findings 4.3 and 4.4 represent a small fraction of NMVOC emissions from the statewide upstream oil and gas development sector, these emissions may be meaningful risk of NMVOC exposure in areas with concentrated exempt infrastructure or when this infrastructure exists in close proximity to human populations.

Conclusion 4.2. LDAR focused on monitoring for methane is useful when monitoring equipment with emissions that have high methane/non-methane hydrocarbon ratios. In this context, methane can be a reasonable indicator of the presence of TACs and other NMVOCs that are intermixed with methane. However, when monitoring emissions from infrastructure or processes containing gases with low methane/non-methane ratios (e.g., condensate tanks, produced water management and disposal, etc.) or little to no methane content (e.g., combustion from diesel engines, combustion emission from natural gas-powered equipment, etc.), methane is not a reliable indicator of TAC and other NMVOC emissions and there is likely no surrogate for these situations. LDAR approaches that focus on measurement of large suites of air pollutant species may be more comprehensive and appropriate for various applications when gas composition is uncertain.

Recommendation 4.1. Enforced vapor recovery and LDAR regulations provide tools to enhance detection and reductions of emissions of methane and NMVOCs, including toxic air contaminants and ozone precursors to the atmosphere. Deploy measures to reduce emissions of toxic air contaminants, and ozone precursors associated with new and existing upstream oil and gas development. These measures include, but are not limited to, the following LDAR and emission control measures:

- Require zero-bleed/zero-emission all pneumatic devices across upstream oil and gas development operations regardless of when they were installed. The Colorado Department of Public Health and the Environment's Air Quality Control Commission's updated *Regulation Number 7: Control of Ozone via Ozone Precursors and Control of Hydrocarbons via Oil and Gas Emissions (Emissions of Volatile Organic Compounds and Nitrogen Oxides)* includes requirements for the use of zero-bleed and zero-emission pneumatic control devices at oil and gas well sites, both for new and modified sources as well as for existing sources, retroactively. This Colorado rule provides precedent and guidance for updated rules in California.
- Remove the "small producer" exemptions for separators and condensate tank systems and require them to comply with the 95% vapor control standard, both at the local and regional district levels and within California's Oil and Gas Methane Regulation.
- Remove the heavy oil exemption (crude oil with API gravity <20) from California's Oil and Gas Methane Regulation Leak Detection & Repair (LDAR) requirements.

Recommendation 4.2. Require air quality monitoring and leak detection and response plans that monitor for air pollutants that are relevant and appropriate for the infrastructure being monitored. Methane may be a useful surrogate for TACs and other pollutants of concern (e.g., toxic air contaminants, ozone precursors) from infrastructure that contains gases with high methane/non-methane hydrocarbon ratios, but is not appropriate as a surrogate when monitoring infrastructure containing gases with lower methane:non-methane hydrocarbon ratios.

SUMMARY FINDING 5.

Produced water contains compounds that are known to be hazardous to human health. Produced water handling and disposal in California has been documented to impact groundwater that is currently or could in the future be used for domestic consumption or agricultural irrigation in California.

Finding 5.1. Organic compounds, such as benzene, as well as salts from unlined produced water ponds have migrated into the subsurface and impacted the quality of regional aquifers in California at distances beyond 2.5 miles (4 km or 13,200 ft). These regional aquifers provide beneficial uses to municipalities and agriculture in California *(Chapter 5, Section 5.5).*

Finding 5.2. Discharge of produced water to the surface (surface spills and discharge to unlined produced water ponds, in particular) pose greater potential for human exposure to chemicals in produced water than subsurface recycling and disposal of produced water via Class II injection wells with proper zonal isolation *(Chapter 5, Section 5.5–5.8)*.

Finding 5.3. While at a smaller scale in recent years, disposal of produced water containing high concentrations of total dissolved solids, heavy metals and volatile organic compounds into unlined produced water ponds continues throughout the southern portion of the San Joaquin Valley. These disposal practices have documented subsurface pathways to groundwater resources that are used for drinking water and agricultural supply. Groundwater monitoring at and near unlined produced-water-pond facilities is relatively sparse, but where monitoring has been undertaken, impact to groundwater has been observed *(Chapter 5, Section 5.5)*.

Finding 5.4. Past and present locations of intentional discharges of produced water to surface water (onshore) cannot be traced in the CalGEM or California Integrated Water Quality System (CIWQS) databases. As a result, locations of potential impact to surface water and sediment are unknown *(Chapter 5, Section 5.6)*.

Finding 5.5. There is no publicly accessible database that contains up-to-date reporting of the volumes of crude oil and produced water spills in California. Additionally, the California Office of Emergency Services (CalOES) database often contains non-specific location data, and operators often report spills as mixtures of produced water and crude oil and sometimes report *de minimis* spills in non-specific measurements (e.g., teaspoons, drops) *(Chapter 5, Section 5.7)*.

Conclusion 5.1. An understanding of produced water composition is essential to assess and manage its potential for human health hazards, risks, and impacts. The lack of publicly available data on the composition of produced water across geographic and geological space and by operator hinders the ability of researchers and risk managers to conduct health-protective produced-water management and to responsibly identify opportunities for reuse of produced water outside of the oilfield.

Conclusion 5.2. Disposal of produced water in unlined produced-water ponds poses risks to California groundwater resources that currently or in the future could be used for public and agricultural water supplies. Groundwater monitoring at and near unlined produced-water-pond facilities is relatively sparse, but where monitoring has been undertaken, impact to groundwater has been observed and documented in California.

Conclusion 5.3. Past and present locations of produced water discharge to surface water must be known in order to determine the types and concentrations of contaminants in surface water and sediment attributable to produced water disposal.

Conclusion 5.4. The ability to reliably characterize and analyze statewide volumes of spilled crude oil and produced water is hindered by the lack of a centralized, analysis-ready database.

Recommendation 5.1. Disposal of produced water in unlined produced-water ponds should be prohibited. Monitoring of subsurface plumes of produced water from existing pond facilities should continue and be expanded in a systematic fashion that prioritizes facilities at most risk of contaminating aquifers that meet the definition of an underground source of drinking water (USDW) or currently or in the future could be used for domestic consumption or agricultural irrigation.

Recommendation 5.2. Comprehensive chemical analyses including targeted and non-targeted bioanalytical tests should be conducted to evaluate the chemical composition, toxicity, carcinogenicity, and other chemical hazards of produced water discharged to the surface or injected into Class II wells where out-of-zone migration is shown to occur. Requirements for these analyses should be consistent statewide and recorded in a publicly available digital database.

Recommendation 5.3. Ensure that the definition of protected groundwater during disposal of produced water into produced-water ponds is consistent with the definition of an Underground Source of Drinking Water utilized in California's Underground Injection Control (UIC) program pursuant to the Safe Drinking Water Act, and for hydraulic fracturing pursuant to Senate Bill 4 (2013). Currently this is <10,000 milligrams per liter (mg/L) total dissolved solids (TDS).

Recommendation 5.4. Establish a comprehensive database of past and present locations of produced-water disposal to surface water and associated annual and cumulative volumes of this disposal.

Recommendation 5.5. Ensure that the California Office of Emergency Services database of spill volume estimates is updated with actual spill volumes (e.g., these values are referred to as "corrected" spill volumes by California Office of Emergency Services) in a timely manner. A centralized, accessible, database of produced water spills should be maintained by the California Office of Emergency Services. Operators should be required to submit separate volumes of spill substances (i.e., distinct volumes of produced water, and crude oil), in standardized measurement units (e.g., barrels or gallons) and include accurate reporting of the latitude and longitude of the spill.

SUMMARY FINDING 6.

Idle, idle-deserted, and abandoned oil and gas wells and other legacy upstream oil and gas infrastructure pose potential near and long-term health risks that are poorly characterized due to limited data and reporting.

More data for these legacy systems can inform and prioritize well plugging and other remediation efforts. A framework for the prioritization of remediation depends on access to key metrics such as surrounding population density, demographics, groundwater resources, propensity or magnitude of leakage, etc.

Finding 6.1. Human health hazards and potential risks from legacy upstream oil and gas infrastructure and pipelines include the release of oil, gas, produced water, radioactive scale (which is considered technologically enhanced naturally-occurring radioactive material, or TENORM), and legacy pipeline treatment chemicals (e.g., polychlorinated biphenyls [PCBs]). Corrosion and weathering of pipeline bodies, welds, and pipeline coatings release heavy metals and hazardous materials such as asbestos *(Chapter 6, Section 6.6)*.

Finding 6.2. Current regulations for the handling and management of oil- and gas-related NORM/TENORM in California are lacking. In recent years, improperly abandoned legacy pipelines in California have resulted in events that released crude oil and oil-water mixtures to the surface, potentially exposing nearby communities to hazards *(Chapter 6, Section 6.6)*.

Finding 6.3. Idle, abandoned, removed, idle-deserted, and deserted pipelines are not required to be reported by operators in pipeline management plans submitted to CalGEM. Information on abandoned legacy infrastructure will depend on requirements from other regulatory agencies or datasets *(Chapter 6, Section 6.6).*

Finding 6.4. CalGEM reports approximately 126,000 plugged and abandoned oil and gas wells in California. However, recent assessments found that the number of abandoned wells is under-reported by 17% or more. There are an estimated 2,500 to 5,000 idle-deserted wells in the state *(Chapter 6, Section 6.6)*.

Finding 6.5. The majority of studies of emissions from idle and abandoned wells in California focus on methane. Studies that have measured non-methane volatile organic compounds or emissions from idle or abandoned wells in California are limited in scope and geographic coverage *(Chapter 6, Section 6.5.1)*.

Finding 6.6. Previous studies of methane emissions from abandoned and idle wells in California have found that most emissions come from a small number of wells that are "super-emitters." Despite this evidence, there are no long-term monitoring requirements of fugitive emissions from abandoned, idle, and idle-deserted wells *(Chapter 6, Section 6.6)*.

Conclusion 6.1. Abandoned legacy infrastructure and pipelines pose hazards and potential risks to the public and these are inadequately documented, assessed, and regulated.

Conclusion 6.2. The assessment of health hazards and risks associated with idle, idle-deserted, and abandoned wells and associated legacy infrastructure (e.g., pipelines) requires accurate information about the number, location, and type of each well, in addition to the composition of gas and liquids emitted and leaking from this infrastructure.

Conclusion 6.3. Mass, rate, and chemical composition of methane and non-methane volatile organic compound emissions from idle and abandoned wells and ancillary infrastructure in California are not well-characterized. Currently available emissions data is inadequate to reliably assess the hazards, risks, and potential impacts of abandoned and idle wells on air and water quality and human health. Loss of abandoned well integrity that results in emissions to the atmosphere or contamination of water resources may go undetected for extended periods of time due to the lack of environmental monitoring.

Recommendation 6.1. Agencies with jurisdiction, including CalGEM, should continue to develop a thorough inventory to compile and maintain records of abandoned legacy infrastructure. Specific locations of all wells, flowlines, gathering lines, pipelines, tanks, and other infrastructure abandoned in-place should be recorded and maintained in a digital database. A process for public access to this database that complies with current security and regulatory requirements should be established. A risk-based decision-making framework should also be developed for in-place pipeline abandonment that accounts for nearby human populations, groundwater resources, future land use, and potential hazards such as PCBs, TENORM, asbestos, and measures of structural integrity of wells, pipelines, and other infrastructure. Science-informed TENORM and PCB thresholds that trigger cleanup requirements should be adopted. Operators that own abandoned pipelines and infrastructure should be required to verify proper abandonment procedures.

Recommendation 6.2. Examine historical records and develop a thorough inventory of abandoned wells in the State, including legacy wells abandoned before current plugging and remediation requirements. Efforts to identify and prioritize idle-deserted wells for plugging and abandonment should be expanded. Sites with idle-deserted or abandoned infrastructure that is sited in areas slated for redevelopment should undergo relevant environmental testing, including studies to assess methane and non-methane volatile organic compound flux, and potential soil and groundwater contamination.

Recommendation 6.3. Additional studies should be conducted to assess the composition of gas contained in and emitted from abandoned, idle, and idle-deserted wells. These studies will equip researchers and risk managers with the data required to evaluate health hazards, risks, and impacts of emissions from this infrastructure in California (e.g., health-relevant concentrations at the part-per-billion (ppb) level using EPA Method TO-15). Samples should be collected directly from production string, bradenhead, or other wellhead features. Random sampling should be undertaken to better characterize the distribution and variability of toxic air contaminants in gas from legacy wells across geographic and geological space. These data should be compiled in a database that also contains other well characteristics such as spud date, date of abandonment or abandonment status, and well depth. Investigations should be undertaken to locate and mitigate potential super-emitters to the atmosphere or wells where lack of zonal isolation is more likely to lead to migration of gas and fluids in the subsurface.

CHAPTER ONE

Introduction

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Figures

1.0 California Oil & Gas Public Health Rulemaking Process

On October 12, 2019, Governor Gavin Newsom signed into law Assembly Bill 1057 (AB 1057), which renamed the oil and gas regulatory body from the Division of Oil, Gas, and Geothermal Resources (DOGGR) to the California Geologic Energy Management Division (CalGEM) and specified that "provisions relating to oil and gas conservation include protecting public health and safety and environmental quality" (Limón, 2019).

To fulfill the health and safety requirements of AB 1057, CalGEM is undertaking a formal rulemaking that will update protections for communities near oil and gas production operations. CalGEM has also convened the California Oil & Gas Public Health Rulemaking Scientific Advisory Panel (or "Panel"), which consists of public health experts, to provide Division staff with relevant scientific information and recommendations (CA DOC, 2019). CalGEM retained Rachel Morello-Frosch, PhD, MPH, of UC Berkeley, as the principal investigator (PI) of the Panel, along with Seth B.C. Shonkoff, PhD, MPH, of PSE Healthy Energy, UC Berkeley, and the Lawrence Berkeley National Laboratory, as the co-PI. In consultation with CalGEM, the PIs identified and enlisted recognized public health experts from across the United States to participate in the California public health oil and gas rulemaking.

The Advisory Panel is composed of 15 members (including the two PIs) with expertise in:

- public health,
- environmental health science,
- exposure assessment,
- epidemiology,
- toxicology,
- engineering,
- preventative medicine,
- pediatric medicine,
- air and water pollution,
- source, fate, and transport,
- spatial data analysis,
- human health hazard and risk assessment, and
- occupational and environmental medicine.

Panel member biographies are included in Appendix A. The tasks of the Advisory Panel generally include:

- Providing relevant scientific information and data from the peer-reviewed literature to guide and support CalGEM's rulemaking decisions, and
- Providing expert analysis, opinions, and recommendations related to a wide variety of public health questions that arise during preparation of the rulemaking documentation.

The Panel has prepared this report to accomplish the above stated tasks, and to delineate its findings, conclusions, and recommendations. More specifically, to prepare this report the Panel:

- Synthesized existing scientific research recommendations and science-based policy recommendations regarding public health and upstream oil and gas development (OGD);

- Reviewed additional peer-reviewed scientific literature and government reports on the public health dimensions of OGD in California and other oil and gas regions in North America; and
- Compiled science-based findings, conclusions, and recommendations regarding public health hazards, risks, and impacts of upstream OGD.

1.1 Purpose and scope this report

In this report, the Scientific Advisory Panel evaluates the human health hazards, risks and impacts associated with *upstream*, *onshore* OGD in California (**Figure 1.1**). The Panel used three key questions to guide their research efforts:

1. What are the hazards, exposures, and human health risks and impacts associated with oil and gas development in the State of California?
2. What are the exposure pathways through which OGD hazards pose risks and impacts to human health and safety?
3. How far do these identified human health and safety risks and impacts extend from oil and gas development processes, and how can these risks and impacts be further mitigated?

The scope of this report covers the life cycle of upstream OGD activities, including field and near-field infrastructure and activities associated with well pad development, well stimulation and completion, well maintenance, well plugging, oil and gas production, underground gas storage, produced water and recovered fluids, and legacy infrastructure and abandonment (**Box 1**).

The report does not cover the midstream and downstream life cycles of oil and gas and thus excludes the manufacturing of materials or equipment used in OGD, transport of produced oil and gas to refineries or utilities, and refining or end-use combustion of hydrocarbons as fuel or chemical feedstock. While upstream OGD releases greenhouse gases that contribute to climate change, this report does not focus on climate change-related public health impacts. Additionally, this report does not focus on occupational health dimensions of upstream OGD, although this topic is discussed briefly in **Box 2**.

The Panel compiled published scientific literature and data available through June 8, 2022, that focused on upstream OGD in the United States and Canada. However, numerous epidemiological studies focused on upstream oil and gas development were published throughout the development of this report. As such, “Chapter 3 — Peer-reviewed Epidemiological Literature Assessing Upstream Oil and Gas Development” was updated to include studies published through July 15, 2023. Additionally, “Chapter 4 — Oil and Gas-Associated Air Pollution, Health Risks and Approaches to Emission Control” briefly mentions CalGEM’s 2024 Request for Information regarding “technologies and processes that can be used to effectively ensure leaks associated with oil and gas operations are being detected” (CalGEM, 2024).

Sources considered in this report included peer-reviewed studies, government reports, and white papers authored or commissioned by academic and research institutions, government agencies, or expert panels.

The Panel reached consensus regarding all findings, conclusions, and recommendations in this report. Consensus means that all panel members reviewed the findings, conclusions, and recommendations and affirmatively agreed that the scientific evidence supports them. Panel members had the opportunity to prepare a dissenting assessment, but no one did so. This report reflects the perspective of the Panel members and not necessarily those of their employers or the institutions with which they are affiliated.

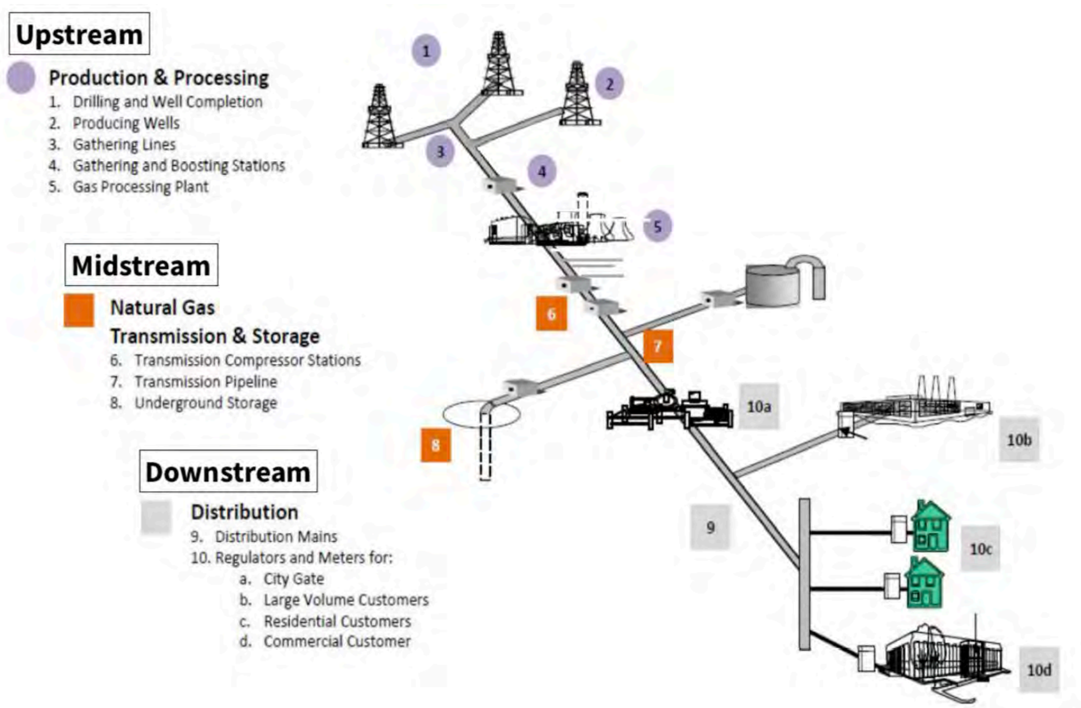

Figure 1.1. Oil and natural gas systems. Source: Adapted from U.S. Environmental Protection Agency and American Gas Association (US EPA, 2016).

Box 1. Underground gas storage in California

There are currently 12 active underground gas storage (UGS) facilities in California (Long et al., 2018). At UGS facilities, natural gas is injected downhole into subsurface reservoirs, stored, and withdrawn for later use. Additionally, wells located at some of these UGS facilities also produce oil.

Given that many UGS facilities have active oil and/or gas wells, and because of some overlap in the emissions and health hazards between UGS and upstream oil and gas development wells, some activities at UGS facilities fall within the scope of this report. However, storage of natural gas that has already been extracted and transferred by pipeline to the storage site is outside of our scope.

In this report, we summarize existing public health findings, conclusions, and recommendations from previous assessments on UGS (Shonkoff et al., 2017) and highlight ongoing efforts to address public health dimensions of UGS in California (e.g., the Aliso Canyon Disaster Health Study) (LACDPH, 2021). Our approach to UGS sites with active oil/gas wells is to focus on defining setback boundaries based on the location and properties of the on-site OGD wells. Although we do not make recommendations specific to UGS facilities, we highlight where UGS facilities are similar to upstream OGD (i.e., with regards to geologic features), and also where UGS operations are different from upstream OGD in the scope of any rulemaking.

Box 2. Occupational health dimensions of upstream oil and gas development in California

The oil and gas industry relies on a workforce of employees and contractors to support upstream OGD operations. Because workers may come into close contact with many chemical and physical hazards associated with OGD, worker health is an important consideration for these operations. Few studies have examined the occupational health dimensions of OGD operations in California.

The *Independent Scientific Assessment on Well Stimulation in California* briefly examined occupational health dimensions associated with OGD in California (Long et al., 2015). These occupational hazards may be associated with well stimulation, such as exposure to respirable crystalline silica (i.e., fine crystalline silica dust or particles) and chemical additives used in hydraulic fracturing, or hydrochloric and hydrofluoric acid used in acid fracturing and matrix acidizing. Occupational health hazards are also associated with general oil and gas industry operations, including but not limited to exposure to toxic air pollutants (Shonkoff et al., 2015). In certain cases, oxygen deficiency and inhalation of hydrocarbon gases and vapors (e.g., hydrogen sulfide) have resulted in sudden death among oil and gas workers in the United States (Harrison et al., 2016).

The *Independent Scientific Assessment on Well Stimulation in California* included the following conclusions and recommendations regarding occupational health hazards and OGD:

> *"Conclusion 6.4. Hydraulic fracturing and acid stimulation operations add some occupational hazards to an already hazardous industry. Studies done outside of California found workers in hydraulic fracturing operations were exposed to respirable silica and VOCs, especially benzene, above recommended occupational levels. The oil and gas industry commonly uses acid along with other toxic substances for both routine maintenance and well stimulation. Well-established procedures exist for safe handling of dangerous acids.*
>
> *….*
>
> *Recommendation 6.4. Assess occupational health hazards from proppant use and emission of volatile organic compounds. Conduct California-based studies focused on silica and volatile organic compounds exposures to workers engaged in hydraulic-fracturing-enabled oil and gas development processes based on NIOSH occupational health findings and protocols."*

Since the publication of Long et al. (2015), at least one health risk assessment has evaluated air pollutant concentrations near oil and gas sites during well stimulation activities. This assessment reported that measured air pollutant concentrations during well stimulation activities did not exceed occupational-based health standards (Shonkoff & Hill, 2020). Of note, this assessment did not evaluate silica exposures.

1.2 Report overview

This report is organized into key topic areas relevant to assessing human health hazards, exposures, risks and impacts associated with upstream, onshore OGD. Each report chapter is briefly described below.

- **Executive Summary — Findings, Conclusions, and Recommendations:** A synthesis of key findings, conclusions, and recommendations based on the report chapters.
- **Chapter 1 — Introduction:** Describing the scope of this report and the approach of the Advisory Panel.
- **Chapter 2 — Stressors Associated with Upstream Oil and Gas Development:** An overview of chemical and physical stressors associated with OGD, with a particular focus on California.
- **Chapter 3 — Peer-Reviewed Epidemiological Literature Assessing Upstream Oil and Gas Development:** A review of the epidemiological studies relevant to assessing the association between upstream OGD and adverse health effects.
- **Chapter 4 — Oil and Gas-Associated Air Pollution, Health Risks and Approaches to Emission Control:** A review of air pollution associated with upstream oil and gas sources; air quality health risk assessments; and best available emission control strategies.
- **Chapter 5 — Produced Water Management and Health:** A review of produced water management approaches employed in California and their relevance to public health.
- **Chapter 6 — Legacy Oil and Gas Infrastructure:** A review of abandoned, idle, and orphaned wells in California, including existing research and identified research gaps on methane and air pollutant emissions.
- **Chapter 7 — California Proximity Analysis:** A proximity analysis is used to characterize populations and sensitive receptor sites located near existing OGD in California.

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Appendix A.

California Oil & Gas Public Health Rulemaking Scientific Advisory Panel

https://www.conservation.ca.gov/calgem/Documents/public-health/Biographies%20(Draft%201).pdf

October 1, 2021 Panel Responses to CalGEM Questions

https://www.conservation.ca.gov/calgem/Documents/public-health/Public%20Health%20Panel%20Responses_FINAL%20ADA.pdf

CHAPTER TWO

Stressors Associated with Upstream Oil and Gas Development

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2.0 Abstract

Upstream oil and gas development (OGD) is responsible for the introduction of both chemical and physical stressors to nearby communities that can impact public health. Chemical stressors from OGD include petroleum hydrocarbons such as benzene, toluene, ethylbenzene, and xylene (BTEX), heavy metals, products of combustion such as criteria air pollutants, odorous compounds, and chemical additives. Physical stressors include noise, light, radioactive materials, induced seismicity, and explosions or fires. Communities may be exposed to varying combinations of multiple stressors.

Although the majority of OGD in California is considered conventional, California has placed policy, regulatory, and scientific emphasis on unconventional OGD, including hydraulic fracturing, matrix acidizing, and acid fracturing. However, most of the impacts associated with unconventional OGD are caused by exposure to stressors from oil and gas production enabled by unconventional extraction methods. Thus, many stressors are intrinsic to both conventional and unconventional OGD, including emissions of radioactive materials and hazardous air pollutants such as BTEX, the use of chemical additives, and noise pollution, odors, and landscape disruption.

The risks associated with chemical and physical stressors from upstream OGD are dependent on the distance between the source and the receptor, whether it be a human receptor or a receptor relevant to human exposure (e.g., a drinking water well). The risk associated with stressors from upstream OGD can be attenuated by increasing the distance between the source and the receptor.

2.1 Introduction

In this chapter, we characterize various stressors associated with upstream oil and gas development (OGD). A stressor is any chemical, physical, or biological entity that can modulate normal functioning or induce an adverse response (NRC, 2012; IPCS, 2004). Below, we discuss chemical and physical stressors[1] associated with upstream OGD and present information specific to upstream OGD in California when available. In this chapter, we also discuss how chemical and physical stressors associated with upstream OGD activities may be attenuated by distance from an upstream OGD source.

Chemical stressors are defined as substances with potential harmful properties (e.g., toxicity, flammability, carcinogenicity) that may be released into environmental media (e.g., air, water, soil) and may pose a risk to human health and/or the environment. These include chemicals that are found in petroleum reservoirs, emitted from upstream OGD activities, and additives used to facilitate well maintenance and oil and gas production. Further discussion of relevant

[1] Given that there is a limited literature on the biological hazards (e.g., hazards that stem from a biological source) associated with upstream OGD, biological hazards were not considered in this report.

environmental exposure pathways and potential health risks of chemical stressors associated with upstream OGD emitted to *air* and *water* are discussed in Chapters 4 and 5, respectively.

Physical stressors generally involve the propagation of energy and therefore include noise, light, radioactive materials, induced seismicity, explosions associated with upstream OGD.

2.2 Chemical stressors

Chemical stressors associated with upstream OGD include toxic compounds recognized as air pollutants and drinking water contaminants. These include petroleum hydrocarbons and metals, products of combustion, odorous compounds (reduced sulfur compounds), and chemical additives used during routine oil and gas activities and during well stimulation activities. Below, we discuss the health relevance of various types of chemical stressors associated with upstream OGD.

2.2.1 Petroleum hydrocarbons and metals

Petroleum reservoirs contain hundreds of petroleum hydrocarbons, which make up the largest fraction of petroleum. Petroleum hydrocarbons include hazardous compounds such as benzene, toluene, ethylbenzene, and xylene (BTEX), and various alkanes (e.g., n-hexane) with known or suspected toxic effects. For example, benzene is a known human carcinogen and hematological toxicant, and chronic exposures to ethylbenzene, toluene, and xylene, and n-hexane, have been associated with carcinogenicity, neurotoxicity, and/or reproductive toxicity (National Cancer Institute, 2019; OEHHA, 2019). BTEX compounds also have been associated with endocrine activity and can impact hormone production, mimic hormones, or inhibit hormone signaling (Bolden et al., 2018). Many petroleum hydrocarbons, such as BTEX and n-hexane, are volatile organic compounds (VOCs) and are recognized as toxic air contaminants (TACs) in the State of California (CARB, 2021a); Benzene, toluene, ethylbenzene, and n-hexane are also listed as carcinogens and/or reproductive toxicants by the State of California through Prop 65 (OEHHA, 2022). Additionally, a number of petroleum hydrocarbons that are volatile organic compounds (VOCs) are precursors that lead to the secondary formation of ground-level ozone, a federally recognized criteria air pollutant associated with adverse respiratory impacts (US EPA, 2015).

Oil and gas bearing formations can also contain high levels of naturally occurring trace metals that can be mobilized and brought to the surface during oil and gas production (CCST et al., 2015; Piper & Isaacs, 1995). Crude oil, natural gas, and produced water may all contain trace metals (Cachia et al., 2018; CCST et al., 2015; Lord, 1991), some of which are hazardous to human health. Cadmium, lead, arsenic, selenium, and nickel are trace metals commonly found in crude oil and are recognized as known human carcinogens and developmental and reproductive toxicants, or are associated with other toxic effects (Lord, 1991; Schreiber & Cozzarelli, 2021; USGS, 2019).

Many petroleum hydrocarbons and metals found in petroleum sources are also recognized as drinking water contaminants and have maximum contaminant levels established for drinking water to protect public health (e.g., benzene; SWRCB, 2020).

2.2.2 Products of combustion

Diesel-powered equipment or gas turbines used during drilling and well stimulation activities (e.g., hydraulic fracturing); flaring or the controlled burning of natural gas from flare stacks; and diesel trucks used to transport equipment and waste products can impair local air quality by emitting incomplete combustion byproducts (e.g., fine particulate matter ($PM_{2.5}$), black carbon, BTEX, nitrogen oxides, carbon monoxide, and formaldehyde) (Johnson et al., 2018; Chen et al., 2022). Exposure to diesel exhaust near oil and gas sites is a recognized respiratory health hazard and diesel-associated particulate matter is a known human carcinogen (CARB, 2021b; McCawley, 2013, 2015).

A recent study monitored particulate matter smaller than 2.5 microns ($PM_{2.5}$) and black carbon at residences located between 715 to 1,288 ft (218 to 393 m) from the sound wall of a large multiwell pad (Allshouse et al., 2019). Hydraulic fracturing activities had the highest median levels of $PM_{2.5}$ and black carbon compared to other well activity phases at these distances (Allshouse et al., 2019). A modeling study of emissions near well pads in Pennsylvania estimated that ambient air concentrations of $PM_{2.5}$ exceeded the U.S. EPA National Ambient Air Quality Standards beyond the state setback distance of 500 ft (152 m), with exceedances increasing as density of wells on a single pad increases (Banan & Gernand, 2018). The flaring of excess natural gas or associated gas during oil and gas production also results in a variety of products of combustion, including black carbon, $PM_{2.5}$, polycyclic aromatic hydrocarbons, and other non-methane hydrocarbons (Schade & Roest, 2018; Weyant et al., 2016).

Additionally, particulate matter and ground-level ozone are criteria air pollutants that arise as secondary air pollutants when oil and gas-associated air pollutants interact with other reactive compounds in the atmosphere and with combustion products from equipment and trucks. For example, VOCs and nitrogen oxides released into the atmosphere can react in the presence of sunlight to form ground-level ozone (CARB, 2020). It is estimated that in 2025, the total number of premature deaths in California attributable to oil and gas sector particulate matter and ozone precursor emissions will be 72 (57–130, 95% confidence interval) (Fann et al. 2018).

2.2.3 Odorous compounds

Odorous compounds associated with upstream oil and gas activities include sulfur-based compounds that occur naturally in petroleum reservoirs, such as hydrogen sulfide (H_2S) and various mercaptans. Odorous compounds can adversely impact the physical and mental health of those experiencing odors, as well as interfere with daily activities and social well-being. Broadly, epidemiological studies have associated malodors with acute physical symptoms such as headaches, nausea, eye and throat irritation, respiratory symptoms including wheeze, and psychosocial stress (Avery et al., 2004; Heaney et al., 2011; Horton et al., 2009; Schiffman et al., 1995; Schiffman et al., 2005). Additionally, some odorous compounds, such as H_2S, are acutely toxic.

2.2.3.1 Hydrogen sulfide (H_2S)

Hydrogen sulfide (H_2S) is an odorous gas with a low odor threshold, which means it can be perceived by human smell at low concentrations ranging from 8 to 130 parts per billion (ppb) (NRC, 2010). Most human organ systems are susceptible to the toxic effects of H_2S, particularly mucus membranes, the central nervous system, the respiratory system, the cardiovascular system, and the gastrointestinal system (Reiffenstein et al., 1992). Exposure to H_2S is associated with known acute health symptoms, including irritation of the eyes, nose, and throat, nausea, vomiting, and headaches (OSHA, n.d., 2005). Exposure to concentrations of H_2S as low as 100 parts per million (ppm) may cause death after 48 hours while concentrations of 500 ppm or greater can lead to rapid collapse, unconsciousness, and death (OSHA, n.d., 2005).

The California Environmental Protection Agency (CalEPA) Office of Environmental Health Hazard Assessment has adopted an acute reference exposure level (REL) for exposure to H_2S for nervous system effects of 30 ppb and a chronic REL for long-term exposure associated with respiratory effects of 8 ppb (OEHHA, 2019). One study found that low-level exposures of 7 ppb H_2S resulted in an increase in emergency room visits (Finnbjornsdottir et al., 2016).

Elevated concentrations of H_2S have been detected near oil and gas sites outside of California. In a community-based monitoring study conducted across five states with oil and gas activities, Macey et al. (2014) reported concentrations of H_2S that significantly exceeded federal health-based guidance values for H_2S. Additionally, a study near the Barnett Shale in Texas found that 32 lease sites (8.0%) had H_2S concentrations greater than 4.7 ppb just beyond the fence line (492–1968 ft away, 150–600 m) with the peak concentration reaching 137 ppb (Eapi et al., 2014). Measured concentrations generally did not correlate well with site characteristics (natural gas production volume, number of wells, or condensate production).

H_2S has also been detected near oil and gas sites in California (Brandt et al., 2015; CARB, 2019; Lillis et al., 2007; Sahagun, 2013a, 2013b; see Chapter 4). Cases of H_2S migration to the surface have been documented in California, posing risks in confined spaces without monitoring. For example, the Edward R. Roybal Learning Center in Los Angeles was developed over part of former Los Angeles City Oil Field and required extensive monitoring and mitigation for H_2S from gas migration (Chilingar & Endres, 2005).

2.2.3.2 Mercaptans and other odorants

Mercaptans are naturally occurring sulfur compounds found in crude oil and natural gas (Krzyzanowski, 2012). Mercaptans in crude oil come in a variety of forms and, along with H_2S, are responsible for the “rotten egg smell” reported near upstream oil and gas facilities (Krzyzanowski, 2012). Exposure to mercaptans and other sulfur-based odorants may result in irritation of the eyes, nose, and throat, coughing, nasal congestion, shortness of breath, nausea, dizziness, stomach discomfort, and headaches, even at “very low levels.” The Texas Commission on Environmental Quality (TCEQ) established interim short-term (1 hour) and long-term (1 year) effects screening levels (ESLs) for various mercaptan and odorant compounds (TCEQ, 2018) (**Table 2.1**). According to TCEQ, short-term ESLs are established to “protect against short-term health effects from discontinuous exposure, nuisance odor, and harmful effects in plants" and long-term ESLs "protect against long-term health effects and plant damage"(TCEQ, 2015).

Table 2.1. Corresponding Texas Commission on Environmental Quality (TCEQ) short-term and long-term effects screening levels for select mercaptans and other odorants. Source: TCEQ (2018).

Mercaptan or other odorant	CASRN	TCEQ Short-Term Effects Screening Levels, ppb (μg/m^3)	TCEQ Long-Term Effects Screening Levels, ppb (μg/m^3)
methyl mercaptan	74-93-1	0.99 (1.9)	0.5 (1)
ethyl mercaptan	75-08-1	0.4 (1)	0.5 (1.3)
n-propyl mercaptan	107-03-9	1.2 (3.7)	0.5 (1.6)
isopropyl mercaptan	75-33-2	0.45 (1.4)	0.58 (1.8)
tert-butyl mercaptan	75-66-1	0.089 (0.33)	0.49 (1.8)
n-butyl mercaptan	109-79-5	0.73 (2.7)	0.49 (1.8)
pentyl mercaptan	110-66-7	0.02 (0.1)	0.5 (2)
tetrahydrothiophene	110-01-0	500 (1,800)	50 (180)
dimethyl sulfide	75-33-2	3 (7.6)	10 (25)

2.2.3.3 Complaints of odors near oil and gas sites

Odors are a common complaint for residents living near OGD sites and numerous studies examining populations living near OGD document self-reported health symptoms with perceived odors (see Chapter 3). California has 35 air districts and residents report odor complaints to the air district responsible for regulating air quality in their region. For example, residents near the Allenco Energy Inc. oil and gas production facility in South Los Angeles reported almost 300 odor complaints to the South Coast Air Quality Management District (SCAQMD) between 2010 and 2014, resulting in over 150 inspections and 18 Notices of Violation (NOV), including six NOVs for nuisance due to odors (SCAQMD, 2015a).

Upon report of nuisance odor complaints, the SCAQMD will assign an investigator to inspect the suspected location of the odor and determine a potential source (SCAQMD, 2021). Specifically, under Rule 1148.1 – Oil and Gas Production Wells,

> "a facility is required to submit a Specific Cause Analysis when there are three or more complaints by different individuals from different addresses, and the source of the odor is verified by District personnel. If this provision is triggered three times within a six-month period, the facility is further required to submit an Odor Mitigation Plan with specific provisions for odor monitoring and mitigation that are spelled out in the rule" (SCAQMD, 2015b).

A recent investigation found that H_2S levels were absent or low at the 15 upstream oil and gas production sites in unincorporated Los Angeles County, based on available data, and no odor complaints were reported for those sites in SCAQMD's database (MRS Environmental, 2017). However, the presence of H_2S varied based on specific oil field conditions, and more environmental data are needed to characterize the extent of H_2S exposures in the Los Angeles Basin. A recent report by the Los Angeles County Department of Public Health stated: "Depending on the type of operations and proximity of people nearby, some EIRs (environmental impact reports) and HIAs (health impact assessments) reviewed for this report concluded that odor events would lead to significant and unavoidable impacts to residents living nearby while others provided evidence that odor mitigation plans would alleviate odor impacts for nearby residents" (LACDPH, 2018). In addition, effects related to odors may be unavoidable at distances out to 1,000 ft (305 m) during loss of containment events, regardless of standard mitigation efforts (LACDPH, 2018). LACDPH (2018) also notes that odors will likely not present a hazard at a distance of 1,500 ft (457 m) from an oil and gas site, though no justification through complaint reporting or dispersion modeling was provided for this determination.

Many complaints near upstream OGD sites in other oil and gas regions are related to noise and odors. Equitable response to complaints is important to consider. A recent study conducted in Pennsylvania found that while the number of complaints filed were similar in counties with different racial demographics, counties with a higher proportion of racial minorities were associated with fewer confirmed impairments, highlighting the possible inequities in addressing oil and gas complaints (Clark et al., 2021). Data on complaints associated with noise, odors, and air pollution are currently not publicly available in California. Furthermore, no peer-reviewed studies have evaluated exposure to noise, light, and odors associated with oil and gas development in California, nor have widespread assessments of complaints been conducted.

2.2.4 Chemical additive usage in upstream oil and gas development

Chemical additives are used throughout the well drilling, construction, completion, and rework[2] process to aid in well cleanout, modify fluid viscosity, and to control pH, clay, corrosion, scale buildup, and microbial activity. Chemicals are also reportedly used for ancillary purposes, such as to mask or neutralize odorous compounds (Fleming & Kim, 2017). Exposure to chemical additives used in upstream oil and gas development may result from accidental spills and leaks, releases to the air during chemical mixing and operations, groundwater contamination, and volatilization from produced water (CCST et al., 2015) Additionally, chemical additives may also transform through environmental degradation or during wastewater treatment (CCST et al. 2015; Kahrilas et al. 2015, 2016). Below we discuss chemical additive usage in California, knowns and unknowns about chemical additive toxicity, downhole chemical transformations, and implications for chemical disclosure and public health.

There are four major sources of publicly available chemical disclosures for oil and gas operations in California: the South Coast Air Quality Management District (SCAQMD), FracFocus, the California Geologic Energy Management Division (CalGEM), and the Central Valley Regional

[2] Rework is any operation subsequent to drilling that involves deepening, redrilling, plugging, or permanently altering in any manner the casing of a well or its function (CalGEM, 2019).

Water Quality Control Board (CVRWQCB). A summary of these four datasets is provided in **Table 2.2.** More information about each of these datasets is provided in Appendix B. It is important to note that the available chemical disclosure datasets are limited in both geographic coverage and the types of oil and gas development activities included because the combined datasets do not cover all upstream oil and gas development activities on a statewide basis. No datasets include the use of chemicals for ancillary purposes, such as odor control agents.

The most recent cross-analysis of all available chemical disclosure datasets was done by the California Council on Science and Technology (CCST). The analysis found 630 unique chemical additives with a Chemical Abstract Service Registry Number (CASRN) were used in California from 2011 to 2018, with an additional 489 chemicals that lacked a CASRN and could not be definitively identified (Shonkoff et al., 2021). Because chemicals and formulations without a CASRN cannot be definitively identified, it cannot be determined if a formulation reported in one dataset (e.g. anionic surfactants) is the same one reported in another dataset based on name alone, resulting in an overestimate of reported chemicals without a CASRN. Previous studies of chemical disclosure datasets are summarized in Appendix B, Table B.1.

2.2.4.1 Physicochemical and toxicological properties of disclosed chemicals

In previous studies of chemical disclosure in California, chemical additives were classified according to the availability of key toxicological and physicochemical properties and their inclusion in federal and state lists of chemicals of concern (CCST et al., 2015; Shonkoff et al., 2021; Stringfellow et al. 2017). The compiled results of these studies are summarized below and in **Table 2.3**.

When experimental values for physicochemical properties and biodegradability were not available, previous studies used U.S. EPA EPI (Estimation Program Interface) Suite™ models to estimate relevant properties (CCST et al., 2015; Shonkoff et al., 2021; Stringfellow et al. 2017). Estimations from EPI Suite™ models, such as BIOWIN™, AOPWIN™, KOWWIN™, KOAWIN™, and HENRYWIN™, are generally accepted by United States regulatory authorities when experimental data are unavailable, and are widely used by the scientific community as inputs for modeling the environmental fate of chemicals (Aronson et al., 2006; Gouin & Harner, 2003; Rücker & Kümmerer, 2012; Scheringer, 2010; Scheringer et al., 2006; Sühring et al., 2020; Wania & Dugani, 2003).

Table 2.2. Upstream oil and gas development chemical usage datasets and associated timeframes used for analysis. Source: Adapted from Shonkoff et al. (2021).

Dataset Name	Source	Timeframe of analysis	Region	Description
FracFocus	Ground Water Protection Council, Interstate Oil and Gas Compact Commission	2011–2018	Analysis limited to California	Composition of hydraulic fracturing fluids. Combines FracFocus 1.0, 2.0, and 3.0 data for completeness.
CalGEM[1]	CalGEM	2014–2018	California	Composition of well stimulation fluids, including, but not limited to, hydraulic fracturing fluids, matrix acidizing fluids, acid fracturing fluids, and recovered fluids within 60 days following the cessation of a well stimulation treatment. Includes disclosures under both interim and final Senate Bill 4 regulations.
SCAQMD	SCAQMD	2013–2018	Los Angeles, Orange, Riverside, San Bernardino Counties	Chemical additives used in routine oil and gas activities (well drilling, well completion, and well reworks) and well stimulation (hydraulic fracturing and matrix acidizing). Does not include enhanced oil recovery, refining, transmission, or storage activities.
AB 1328	CVRWQCB	2014–2018	Southern San Joaquin Valley	All chemical additives used in petroleum production, treatment, and transportation processes that generate produced water for irrigation. Includes wells producing under primary, secondary, and enhanced oil recovery (cyclic steaming, steam flooding, and water flooding). Includes data from operators and their chemical suppliers.

1. CalGEM was formerly known as the Division of Oil, Gas, and Geothermal Resources (DOGGR).
Abbreviations: SCAQMD – South Coast Air Quality Management District; CalGEM – California Geologic Energy Management Division; AB – Assembly Bill, CVRWQCB – Central Valley Regional Water Quality Control Board).

A significant number of chemical additives were included in key federal and state lists of chemicals of concern. Thirty-six chemicals were classified as known or probable human carcinogens by the International Agency for Research on Cancer (IARC), and 40 were listed in Prop 65 assessments as chemicals known to cause cancer or reproductive harm. Fifty-one chemicals were classified as Clean Air Act hazardous air pollutants (HAPs) and 70 were considered toxic air contaminants (TACs) by the California Air Resources Board (CARB). An additional 24 chemicals were listed on U.S. EPA Drinking Water Standards and Health Advisories (DWSHA) tables and 118 chemicals were on the Agency for Toxic Substances and Disease Registry (ATSDR) Substance Priority List. Thirty-eight chemicals were classified as Globally Harmonized System of Classification and Labeling of Chemicals (GHS) category 1 or 2 for acute oral or inhalation toxicity, that is, they are considered highly toxic and potentially fatal by these routes of exposure (United Nations, 2021).

Major data gaps remain regarding the physicochemical, biodegradability, and chronic toxicity properties of chemicals with a CASRN. Approximately 75% of chemical additives with a CASRN did not have available chronic toxicity data, 28% did not have available acute toxicity data, 41% were not readily biodegradable or did not have any biodegradability data, and 37% did not have any data on key physicochemical properties. These chemical properties are important to determine environmental fate and transport and potential human health impacts. It is important to note that the absence of data regarding chemical toxicity is not evidence that there are no potential negative human health impacts.

In summary, many chemicals used in upstream OGD operations in California are disclosed and several can be characterized with regard to human health impacts. However, there are still a significant number of chemical additives that are not disclosed or not sufficiently characterized to assess their potential human health impacts. Statewide policies that require all oil and gas operators to disclose the identities and amounts of chemical additives used, regardless of the type of upstream oil and gas development activity or recovery method, would help close data gaps and facilitate future hazard and risk assessments. Chemical additives are generally absent from air monitoring risk assessments of upstream OGD; however, previous assessments have found that some compounds will readily evaporate (Shonkoff et al., 2019) and may be a hazard to human health (Chapter 4, Appendix D).

Table 2.3. Number of chemicals disclosed in oil and gas datasets, classified by data availability or presence on international and national priority lists. Source: Shonkoff et al. (2021).

		Datasets				
Chemical Information Category		**FracFocus 1.0, 2.0, 3.0**[1]	**SCAQMD**	**AB 1328**[2]	**CalGEM**	**All Datasets Combined**
Identification	Proprietary/Trade Secret	82	327	80	0	489
	Chemicals with CASRN	315	324	285	272	630
Toxicity	No Acute Toxicity Data	70	89	63	57	180
	GHS Category 1 or 2 (Acute oral or inhalation toxicity)	19	20	18	14	38
	No Chronic Toxicity Data	227	232	198	199	476
Biodegradation	No biodegradability data	53	61	53	47	132
	Not readily/not inherently biodegradable	54	51	45	55	127
Carcinogens	IARC Group 1, 2A, 2B	19	18	25	17	36
	California Prop 65	19	19	33	16	40
	NTP Known or anticipated carcinogen	12	12	19	11	25
Air Pollutants	Clean Air Act Hazardous Pollutant	21	24	31	24	51
	CARB Toxic Air Contaminant List	33	36	45	36	70
	CARB Hot Spots List	34	39	47	36	74
Other Priority Lists	European Commission endocrine disrupting chemical	3	3	1	2	3
	OSPAR Substance of Possible Concern List	2	2	2	2	3
	EU REACH Substance of Very High Concern	7	4	3	4	8
	ATSDR Substance Priority List	58	77	81	50	118
	US EPA DWSHA	14	11	20	12	24
	US EPA CCL4	5	6	8	4	11

Chemical Information Category		Datasets				
		FracFocus 1.0, 2.0, 3.0[1]	**SCAQMD**	**AB 1328**[2]	**CalGEM**	**All Datasets Combined**
Physical Chemical	No physicochemical properties (log K_{ow}, log K_{oc}, K_H, and vapor pressure)	91	123	97	77	233

1. All proprietary/trade secret chemicals for the FracFocus dataset were reported in FracFocus 1.0 or 2.0, prior to 2016.
2. Number of proprietary chemicals and chemicals with CASRN do not reflect the updated AB 1328 dataset released in 2021 (CVRWQCB et al., 2021).

Abbreviations: CASRN - Chemical Abstracts Service Registry Number; GHS - the Globally Harmonized System of Classification and Labelling of Chemicals; IARC - International Agency of Research on Cancer; NTP - National Toxicology Program; CARB - California Air Resources Board; EU REACH - European Regulation on Registration, Evaluation, Authorisation and Restriction of Chemicals; ATSDR - Agency of Toxic Substances and Disease Registry; US EPA DWSHA - Drinking Water Standard and Health Advisories; US EPA CCL4 - United States Environmental Protection Agency Contaminant Candidate List 4; SCAQMD - South Coast Air Quality Management District; CalGEM - California Geologic Energy Management Division; AB - Assembly Bill.

2.2.4.2 Comparison of chemical use between datasets

An analysis of chemical use among the various chemical disclosure datasets revealed significant overlap among all datasets and is presented in **Figure 2.1**. (Stringfellow et al., 2017; Shonkoff et al., 2021). Of the 630 chemicals with a CASRN, 316 were reported in more than one dataset, with 178 chemicals reported in three or more datasets. The remaining 314 chemicals were unique to one dataset. Both the SCAQMD and AB 1328 datasets contained more than 100 unique chemicals with a CASRN that were not reported in any other datasets. The majority of chemical additives in the FracFocus and CalGEM datasets were identified in both datasets; this overlap is likely due to the fact that both datasets include hydraulic fracturing activities. Chemicals reported without a CASRN were not included in this comparison because (1) they could not be uniquely identified, and (2) any comparison between datasets based on the reported name alone would be inaccurate.

The significant overlap in chemical usage across datasets indicates the use of some chemical additives is widespread and not limited to a particular region, recovery method, or well activity. As such, the potential health implications of chemical usage in upstream OGD may exist across different regions, recovery methods, and activities. Current regulations concerning chemical disclosure or the prohibition of select chemical additives that only apply to specific upstream OGD activities (e.g., well stimulation) may overlook the potential health implications from the use of the same chemical additives in other well activities and recovery methods. Additionally, because roughly half of all chemicals with a CASRN were unique to a single dataset, the lack of universal chemical disclosure for all upstream oil and gas activities prevents a thorough assessment of the potential health implications of OGD chemical usage.

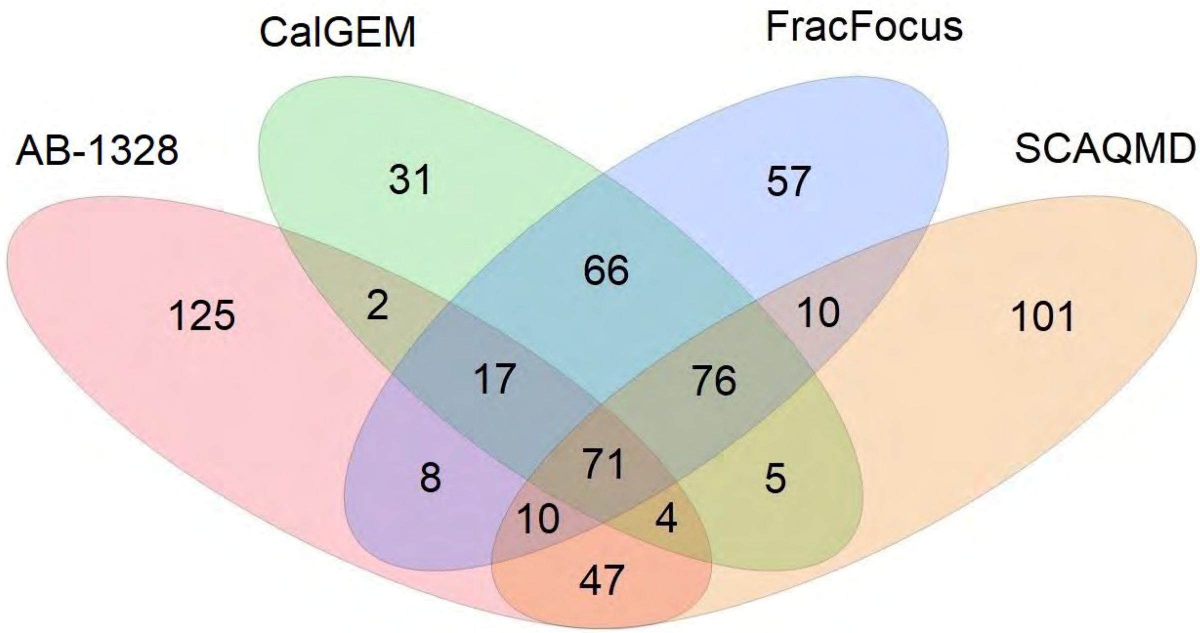

Figure 2.1. Venn diagram showing overlap in the number of chemicals with a CASRN used in SCAQMD, AB 1328, CalGEM, and FracFocus datasets. Source: Adapted from Shonkoff et al. (2021).

2.2.4.3 Chemical additive transformation

Chemical additives used in oil and gas production have the potential to undergo subsurface chemical transformations through reactions with other additives, naturally occurring compounds, or microbes, and then return to the surface via flowback and produced water (Kahrilas et al., 2016; Kortenkamp et al., 2007; Teuschler & Hertzberg, 1995; Wilkinson et al., 2000). Although degradation pathways and products have been established for some chemical additives under standard state conditions, downhole conditions — including high temperatures and pressures — can result in altered biodegradation potentials and unexpected chemical reactions and degradation products (CCST, 2015; Kahrilas et al., 2015). For example, chemicals used in hydraulic fracturing in California (guar gum, borate and zirconium crosslinkers, and oxidative breakers) can form various di- and trihalomethane compounds in simulated downhole conditions (Sumner & Plata, 2019). Additionally, some relatively nontoxic chemical additives may transform into more toxic or more environmentally persistent compounds (Kahrilas et al., 2015). Although poorly understood, the products of downhole chemical transformations can pose risks to human health when released to the environment (Abdullah et al., 2017). Chemical additive disclosures do not capture these potential chemical transformations.

Chemical transformations may also occur as a result of subsequent treatment and disposal. Water disinfection byproduct (DBP) precursors have been identified in untreated oil and gas produced water (Harkness et al., 2015; Liberatore et al., 2017; Parker et al., 2014). When produced water is released into surface waters, DBPs have been detected downstream from points of discharge (Hladik et al., 2014). Toxicity of various regulated and unregulated DBPs has been noted in the literature (Liberatore et al., 2017). As such, conducting produced water monitoring for disclosed chemicals is appropriate, but may not provide conclusive results with respect to the toxicological profile of any given source of produced water. The deployment of monitoring approaches that can provide information on DBPs and other transformation byproducts, or non-targeted water monitoring methods that assess the toxicity and mutagenicity of water without identifying specific chemical mechanisms (e.g., bioassays), may help to close these data gaps. These monitoring approaches are most important for discharge of produced water to the surface and for produced water reuse outside of the oilfield.

It is also possible, and likely, that some portion of chemical transformation products that return to the surface will volatilize from produced water and become airborne pollutants. However, because transformation products are expected to either remain in the subsurface or initially return to the surface with flowback or produced water, chemical additive transformations are discussed in further detail in Chapter 5. Emissions from produced water are also discussed in Chapter 5.

2.3 Physical stressors

In this section we discuss physical stressors associated with OGD, including noise, light, radioactive materials, induced seismicity, and explosions and fires.

2.3.1 Noise

Noise, one of the most common complaints of residents near oil and gas well sites, is emitted from trucks and equipment during oil and gas well site operations. Noise has been measured 100–1,800 ft (30–550 m) from oil and gas well sites at levels known to negatively impact sleep, cardiovascular health, and child behavior and well-being (Blair et al., 2018; Ferrar et al., 2013; Collier-Oxandale et al., 2020).

2.3.1.1 Noise exposure and human health

Chronic noise at levels ranging from 55 to 65 dBA[3] can disturb sleep. Daytime noise in the range of 65 dBA has been associated with objective measures of shorter nighttime sleep duration, less slow wave sleep, and lower sleep efficiency (Chen et al., 2018). Additional studies examining nighttime noise and sleep found that outdoor, nighttime noise levels above 55 dBA were linked to higher odds of self-reported insomnia (Halonen et al., 2012) and patients in hospital rooms with 24-hour noise levels of ~64 dBA had disrupted sleep quality (Park et al., 2014). There is a strong body of evidence linking disturbed sleep, especially short sleep duration, to hypertension and cardiovascular disease (Aziz et al., 2017; Cappuccio et al., 2011; Cappuccio & Miller, 2017; Drager et al., 2017; Itani et al., 2017; Javaheri & Redline, 2017; Jike et al., 2018; Khan & Aouad, 2017; Kim et al., 2019; Knutson, 2010; Lunsford-Avery et al., 2018; St-Onge et al., 2016; Yin et al., 2017). A recent meta-analysis indicates that traffic noise increases the risk of sleep disorders that may act as important mediators in the relationship between noise and cardiovascular disease (Basner & McGuire, 2018).

[3] A-weighted decibel (dBA) is an expression of the relative loudness of sounds as perceived by the human ear.

Additionally, exposure to chronic noise starting at 40 dBA can negatively impact cardiovascular health. Starting at 40, 45, and 50 dBA, the risk of incident atrial fibrillation, hypertension, and coronary heart disease increases by 6-8% per increase of 10 dBA (Hahad et al., 2019). Simulated aircraft noise at night with peak levels of 60 dBA were associated with elevated epinephrine and blood pressure, impaired endothelial function, and lower sleep quality (Schmidt et al. 2013; 2015). Specifically, the researchers observed that an 8 dBA increase in simulated aircraft noise was associated with 4.1 mmHg (millimeters of mercury) increase in systolic blood pressure (Schmidt et al. 2015). Older adults may be particularly susceptible and vulnerable to noise exposures. For each 10 dBA increase in A-weighted noise, starting at 55 dBA, stroke risk increases 14% in adults ≥65 years (Hahad et al., 2019). A meta-analysis of 24 field studies on noise and sleep determined that individuals in their fifties are most vulnerable to the adverse effects of noise on sleep (Miedema & Vos, 2007). Many aging adults have limited social ties and financial resources, which reduce the ability to respond resiliently to mitigate the impacts of environmental conditions such as noise disturbance (Administration for Community Living, 2019; Fernandez et al., 2002; Meyer, 2017; Ngo, 2001). Aging adults tend to spend more time at home and are more likely to become housebound (Qiu et al., 2010; US Bureau of Labor Statistics, 2019).

Several studies indicate that noise exposures may negatively impact child behavior and well-being. A meta-analysis of three studies, Schubert et al., (2019) found a 10% increase in inattention/hyperactivity symptoms and 9% increase in total behavioral symptoms per 10 dB increase in exposure to road noise. A study in Norway identified a 36% increase in sleep disturbances in girls per 10 dB increase in road traffic noise (Weyde et al., 2017a). Average road noise exposure between ages 3 to 8 years was associated with a 1.3% increase in inattention per 10 dB increase in average noise exposure, indicating a potential cumulative effect from long term exposures (Weyde et al., 2017b). Finally, a recent meta-analysis of noise exposures and cognitive ability concludes that there is limited evidence that chronic noise exposures could impact cognitive performance in school children (Clark et al., 2020).

2.3.1.2 Noise levels observed near oil and gas sites

Noise is one of the most common complaints from residents near oil and gas well sites. Between 35 to 55% of participants in a Marcellus Shale region survey reported noise as a perceived stressor from OGD (Ferrar et al., 2013). In Colorado, 123 out of 330 complaints reported to the Colorado Oil and Gas Conservation Commission in 2015 were noise concerns (Blair et al., 2018).

While there are currently no health-based guidelines for environmental noise from oil and gas sites, the World Health Organization Guidelines for the European Region recommend that noise from traffic, railways, aircraft, and wind turbines not exceed 45–54 dBA over a 24-hour period and 40–45 dBA at night (World Health Organization, 2018). For context, a whisper is measured at 25 dBA, a vacuum cleaner at 75 dBA, and a jet engine at 100 ft (30 m) at 140 dBA (Yale University Environmental Health and Safety, 2021). Studies in Colorado, Pennsylvania, Texas, and West Virginia have documented noise levels exceeding WHO guidelines for the European regions. At this time, there are no peer-reviewed studies evaluating noise levels near oil and gas development in California. **Table 2.4** and **Table 2.5** summarize results from published studies on noise levels around oil and gas well sites in the United States. Appendix B provides explanations of noise measurements. Early evaluation of noise around oil and gas well sites reported audible noise levels ranging from 47–87 dBA at 100–1000 ft (30–305 m) from oil and gas well sites with no sound mitigation in place (Witter et al., 2013; Hays et al., 2017). A later study, documenting both audible and low frequency vibrational noise, reported noise levels at 350 ft (107 m) from oil and gas well sites ranging from 41–72 dBA and 58–82 dBC[4] without a sound wall, and 57–59 dBA and 67–76 dBC with a sound wall (Radtke et al., 2017). In more recent and comprehensive studies, Blair et al. (2018) and Allshouse et al. (2019) continuously measured audible noise and low frequency vibrational noise at four Colorado homes located 715–1805 ft (218–500 m) from the perimeter of a 22 oil and gas well site with a sound wall in place throughout development and into production. These sets of noise measurements included a combination of noise from multi-well site equipment and truck traffic moving supplies to and from the site. During all phases of development and production, audible noise exceeded the WHO's daytime (45–54 dBA) and nighttime (40–45 dBA) guidelines, as well as levels known to affect sleep, cardiovascular health, and child behavior and wellbeing (50 dBA) (Basner et al., 2014; Hume et al., 2012). Additionally, low frequency noise exceeded a 65 dBC suggested threshold, which is based on a limited literature on the health effects of low frequency vibrational noise (Blair et al., 2018; Broner, 2010; Hays et al., 2017). Notably, noise levels were well above the predevelopment levels of 42.8 dBA and 55.8 dBC. Once well pad development transitioned to the ~30-year production phase, noise levels still exceeded 53 dBA and 72 dBC, an increase of 10 dBA and 16 dBC, respectively, from pre- to post- site development. Exceedances occurred both day and night on all days of the week. Increased nighttime noise is a particular concern because people are more likely to be at home and thus adversely impacted.

[4] C-weighted decibels (dBC) rely on a type of frequency weighting that is used when measuring the amount of noise in an environment and is primarily used for peak measurements or for measuring noise above 100 decibels.

Table 2.4. Summary of audible noise measurements by distances from oil and gas well sites (dBA).[1]

State	Study	Distance from site (feet)	Truck traffic (dBA)	Site preparation and/or drilling (dBA)	Drilling (dBA)	Hydraulic fracturing (dBA)	Hydraulic fracturing and/or Well Completions (dBA)	Production (dBA)
	Without Sound Wall							
Texas	Hayes et al. (2017)	100	-	-	75–87	-	-	-
Texas	Hayes et al. (2017)	200	-	-	71–79	-	-	-
Texas	Hayes et al. (2017)	300	-	-	65–74	-	-	-
Colorado	Radtke et al. (2017)	350	-	-	63–66	65–72	62–65	41–59
Texas	Hayes et al. (2017)	400	-	-	60–71	-	-	-
Texas	Hayes et al. (2017)	500	-	-	56–68	-	-	-
Colorado	Witter et al. (2013)	500	-	-	56–60	-	-	-
Texas	Hayes et al. (2017)	600	-	-	54–59			
West Virginia	Hayes et al. (2017)	625	56–73	58–69	54	47–60	55–61	
Texas	Hayes et al. (2017)	700	-	-	51–55	-	-	-
Texas	Hayes et al. (2017)	800	-	-	51–54	-	-	-
Wyoming	Hayes et al. (2017)	984	-	-	52.5	-	-	-
Colorado	Witter et al. (2013)	1,000	-	-	65–69	-	-	-
	With Sound Wall							
Colorado	Radtke et al. (2017)	350	-	-	57–59	59	-	-
Colorado	Allshouse et al. (2019)	715	-	-	38.4–75.2	-	-	
Colorado	Allshouse et al. (2019)	737	-	-	38.3–90.4	40.2–76.7	39.2–91.9	37.6–79.0
Colorado	Allshouse et al. (2019)	868	-	-	37.2–78.9	37.6–79.0	36.6–92.5	36.5–92.3
Colorado	Allshouse et al. (2019)	1,288	-	-	35.9–74.5	-	-	-
Colorado	Blair et al. (2018)	1,050–1,805	-	35.9–89.2	-	-	-	-

- Not measured

[1] A-weighted decibel (dBA) is an expression of the relative loudness of sounds as perceived by the human ear. The World Health Organization Guidelines for the European Region recommend that noise from traffic, railways, aircraft, and wind turbines not exceed 45–54 dBA in the daytime and 40–45 dBA at night (World Health Organization, 2018).

Table 2.5. Summary of low vibrational noise measurements by distance from oil and gas well site (dBC).[1]

State	Study	Distance from center of site (feet)	Drilling (dBC)	Hydraulic Fracturing (dBC)	Hydraulic Fracturing and Well Completions (dBC)	Production (dBC)
Without Sound Wall						
Colorado	Radtke et al. (2017)	350	77–80	77–82	76–77	58–74
With Sound Wall						
Colorado	Radtke et al. (2017)	350	67–76	73–74	-	-
Colorado	Allshouse et al. (2019)	715	56.2–98.5	-	-	-
Colorado	Allshouse et al. (2019)	737	57.1–106.4	60.4–98.2	57.5–107.6	55.8–101.0
Colorado	Allshouse et al. (2019)	868	52.4–96.6	57.5–106.5	55.5–106.2	54.0–106.7
Colorado	Allshouse et al. (2019)	1,288	54.5–96.4	-	-	-

- Not measured

[1] C-weighted decibels (dBC) rely on a type of frequency weighting that is used when measure the amount of noise in an environment and is primarily used for peak measurements of for measuring noise above 100 decibels.

2.3.2 Light

Artificial light at night (ALAN) may emanate from oil and gas sites (Boslett et al., 2021). ALAN associated with upstream oil and gas activity presents a potential hazard with a range of acute and chronic health risks, particularly for communities with heavy drilling operations.

More generally, health impacts from exposure to ALAN are associated with symptoms of mental health disorders, increased risk of mortality, and sleep deprivation, which can cause secondary effects such as reduced cognitive function and reduced productivity (Chepesiuk, 2009; Touitou et al., 2017). In addition, exposure to ALAN has been associated with elevated incidence of cancer, including breast cancer, as well as metabolic and mood disorders (Chepesiuk, 2009; Walker et al., 2020). While the evidence is sparse, studies suggest this association between cancer and ALAN may be due to disruptions to the circadian and neuroendocrine systems, thus promoting tumor growth (Chepesiuk, 2009; Walker et al., 2020). Disruptions to the circadian system are also associated with cardiovascular disease, depression, and insomnia (Chepesiuk, 2009; Walker et al., 2020).

A small number of peer-reviewed studies have examined ALAN associated with oil and gas activities. The peer-reviewed literature includes five studies, two of which were conducted in Pennsylvania (Ferrar et al., 2013; Perry, 2013); one in the Bakken Shale region (North Dakota, Montana, Canada) (Boslett et al., 2021); one in the Guernsey and Noble Counties of Ohio (Fisher et al., 2018); and one in West Virginia (McCawley, 2013).

Studies focused on OGD show that various sensory stimuli, including ALAN, noise, and vibrations from drilling operations, may contribute to psychosocial stress (Ferrar et al., 2013; Fisher et al., 2018); anxiety and depression due to changes in quality of life (Perry, 2013); and sleep deprivation and poor physical and mental health (Boslett et al., 2021; Fisher et al., 2018). In the case of Boslett et al. (2021), the authors found sufficient evidence to suggest that the rapid expansion of unconventional oil and natural gas development within rural communities has led to a significant increase of ALAN. One study found no association between drilling activity and increased ALAN (McCawley, 2013). To date, no peer-reviewed studies evaluating OGD and light pollution, or complaints related to upstream OGD and light, have been conducted in California.

2.3.3 Radioactive materials

Oil and gas production can transport naturally occurring radioactive materials (NORM) from the subsurface to the surface (US EPA, 2022a). NORM that becomes environmentally accessible or concentrated due to human activities is referred to as technologically enhanced naturally occurring radioactive materials (TENORM) (US EPA, 2022a). Exposure to radiation can result in impaired lung function, oxidative stress, increased blood pressure, and can increase the risk of cancers, especially among sensitive populations such as children and fetuses (Deziel et al., 2022; Li et al., 2018; Nyhan et al., 2018, 2019; US EPA, 2022b).

Elevated levels of TENORM are commonly found in waste products associated with oil and gas activities, such as solid waste and drill cuttings, and in produced water (US EPA, 2000a, 2022a). TENORM may also accumulate as scale in pipes and other upstream infrastructure, complicating the decommissioning process (US EPA, 2022a). Various radioactive compounds found in oil and gas waste streams, such as radium-226 and radon-222, are particularly persistent in the environment because radium-226 — with a 1,600-year half-life — is continuously produced from the very long-lived uranium-238, and the short-lived radon-222 and its progeny are continuously produced from the decay of radium-226 (US EPA, 2000b). Due to exemption of oil and gas waste from Subtitle C of the Resource Conservation and Recovery Act (RCRA), oil and gas exploration and production waste is not designated as hazardous waste and is therefore not required to be disposed of at hazardous waste facilities (US EPA, 2002). Radioactive compounds present challenges in waste treatment and disposal. Disposal of OGD waste in landfills (despite sometimes exceeding landfill standards) is a common practice in some states such as Pennsylvania (Hill et al., 2019). Recently, New York State, which had accepted oil and gas waste from Pennsylvania oil and gas activities, decided to halt the practice unless the waste meets non-hazardous designation (N.Y. Senate Bill S3392, 2020).

Radioactive materials released into the environment can also spread through airborne transport (Li et al., 2020). For example, radon-222 decay products react with atmospheric gases and water and attach to airborne particles (Brager et al., 1991; Li et al., 2020; Yamada et al., 2004). A recent study that considered wells primarily in shale formations in the eastern half of the United States detected increased gross beta-particle radiation downwind of unconventional oil and gas wells in various parts of the country (Li et al., 2020).

In a 1996 study of oilfield TENORM in California, radiation measurements were taken in 70 oil and gas fields through the state, and 124 samples from sites expected to have elevated TENORM levels were analyzed for radionuclides (DHS Radiologic Health Branch & DOGGR, 1996). Although the majority of radiation measurements and samples were at or near background levels (<5 pCi/g [picocuries per gram] of radium), elevated levels of TENORM (>5 pCi/g) were found in upstream pipe scale, tank bottoms, sludge, water filters and softeners, and natural gas processing equipment such as gas lines where propane was being distilled (DHS Radiologic Health Branch & DOGGR, 1996). Overall, the study concluded that TENORM from oil and gas development is expected to have a low impact on public health during normal operations; however, precautions may be needed to limit worker exposure during operations, site cleanup, and decommissioning (DHS Radiologic Health Branch & DOGGR, 1996).

TENORM can be present in upstream pipelines that transport both produced water and oil/gas from the wellhead (DHS Radiologic Health Branch & DOGGR, 1996). From an exposure viewpoint, the immediate concern regarding exposure to TENORM is gamma radiation exposure from contaminated scale in buried pipelines, because beta and alpha particles will not travel any appreciable length in soil. However, the primary, long-term concern is future land use management and the possibility of redevelopment in areas with buried pipelines (Pipeline Abandonment Steering Committee, 1996). Excavation during redevelopment may disturb TENORM-contaminated pipelines, increasing the potential for gamma radiation exposure and the mobilization of TENORM as dust. Radon-222 gas may also accumulate in overlaying buildings, increasing the potential for exposure. See Chapter 6 for more details on exposure to legacy TENORM.

2.3.4 Induced seismicity

To facilitate oil and gas production, certain extraction techniques (e.g., hydraulic fracturing) and the disposal of produced water (down Class II Underground Injection Control disposal wells), require injection of fluids and material into the subsurface under high pressure. Pressurized injection into the subsurface can result in human-caused earthquakes, also referred to as induced seismicity (Skoumal et al., 2018). Induced seismicity has been attributed to hydraulic fracturing operations for oil and gas production and underground injection of produced water for disposal in other areas in North America (Schultz & Wang, 2020; Skoumal et al., 2018; Wang et al., 2020). In addition to physical hazards and safety risks, seismic events may also contribute to increased psychological responses, including anxiety (Casey et al., 2018). In California, there have been no reported cases of induced seismicity associated with produced water injection. However, it is difficult to distinguish between California's frequent natural earthquakes and those possibly caused by produced water injection; generally, this is easier to investigate anthropogenic sources of seismicity in areas with very low natural seismicity rates (Long et al., 2015). Some studies have found evidence of induced seismicity from fluid injections in California; however, the results were inconclusive (Goebel et al., 2015; Goebel & Shirzaei, 2021; McClure et al., 2017).

2.3.5 Explosions, fires

Another safety aspect of upstream oil and gas production is the potential for explosions and fires during production and processing. Due to the various flammable, explosive materials and potential ignition sources (e.g., electrical shocks, sparks caused by mechanical friction) often found at oil and gas well sites, fires and explosions occasionally occur during oil and gas operations (Blair et al., 2017).

Blair et al. (2017) assessed the frequency of explosions and fires at active well sites in Colorado and Utah and found 183 events reported between 2006 to 2015, with 116 in Colorado and 67 in Utah. The number of wells where fires and explosions were reported encompassed only 0.03% and 0.07% of active wells in Colorado and Utah, respectively. Even so, these events can lead to fatalities and critical injuries, as demonstrated by a review conducted by the U.S. Occupational Safety and Health Administration of reported fire and explosion events near oil and gas sites. A review of 77 fire and explosion incidents by Puskar (2014) reported to the U.S. Occupational Safety and Health Administration found that oil and gas operations resulted in 42 deaths and 87 injuries between 2010–2014.

Haley et al. (2016) investigated historical events and published modeling and air pollution data and concluded that setback distances ranging from 150 to 1,500 ft (46 to 457 m) in the Marcellus, Barnett, and Niobrara shale plays do not appear sufficient to protect public health and safety from explosions and radiant heat from uncontrolled fire from OGD activities. The authors note that the (now outdated) setback distance of 350 ft (107 m) from an outdoor recreational area in Colorado would result in second degree burn blisters after 22 seconds of exposure to a fire incident at an oil and gas site.

2.4 Conceptual overview of stressor attenuation by distance

Intensity of many exposures decrease with distance, although the potential for dispersion and degree of attenuation varies by stressor. We present evidence for the attenuation of stressors by distance for the following stressors: pollutant emissions to air, surface water, and the subsurface environment; noise; and vibrations. **Figure 2.2** provides a conceptual overview of the dispersion of stressors off site from oil and gas operations.

The attenuation, or reduction of intensity, of a stressor by distance varies by the type of stressor and the specific properties of the stressor of interest. For example, physical agents like noise and radiation that emanate from a point source theoretically attenuate following the inverse distanced squared or “r-squared rule” (Lamancusa, 2000). However, in reality there are other factors that influence the attenuation. For the propagation of sound through air, the influence of sound wave reflection and refraction, as well as wind, can alter the theoretical noise propagation. Other stressors we consider — vibration and pollutant emissions to air, water, and the subsurface — have attenuation rates different from inverse-distance squared, but typically greater than a simple linear decay. **Figure 2.3** provides an illustration of the theoretical attenuation that one might expect as a function of relative distance for different categories of stressors. Equations used to derive each attenuation curve are described in Appendix B.

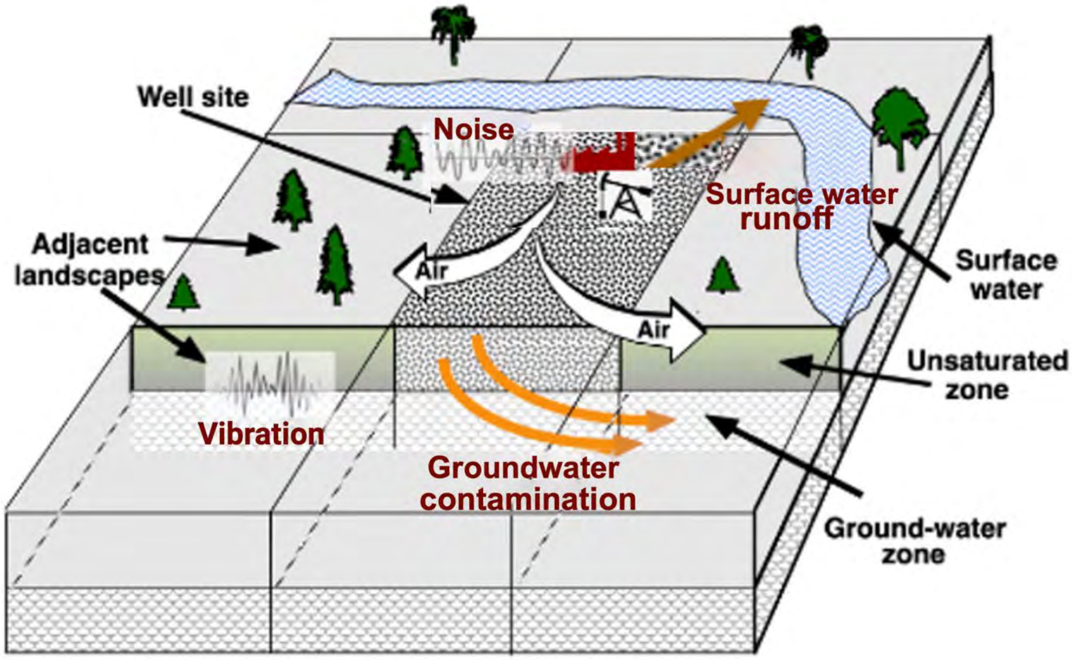

Figure 2.2. Overview illustration of the transport and attenuation of stressors off-site from oil and gas operations.

Figure 2.3 shows theoretically — in the absence of reflection, refraction, and wind effects — how sound (or noise) attenuation out to a relative[5] distance of 4.5 has the most rapid decay of intensity with relative distance, tracking a true or approximate r-squared-decay relationship. Vibration follows an exponential decay and initially attenuates more slowly than sound. For the two examples of air dispersion, one for neutral conditions and one for stable air, we see an attenuation that closely tracks r-squared decay and exponential decay, falling off initially roughly r-squared, but then flattening out to linear dilution that tapers off at greater distance. For groundwater (Domenico & Robbins, 1985) and surface water (van Leeuwen & Vermeire, 2007), the long-term attenuation with distance is much flatter, with an initial near-field r-squared dilution, but trends to a shallow curve best described as $1/\sqrt{r}$. This implies that over long periods, subsurface plumes have a long reach. However, even in short time frames the plume capture zone is wide enough to be short relative to the distance to the nearest groundwater well. It is important to note that while **Figure 2.3** provides a framework to consider attenuation of a range of stressors by distance, additional factors (e.g., directional dispersion, topography, atmospheric stability, mitigation measures impacting sound reflection) ultimately impact the true attenuation of stressors on a site-specific basis.

[5] Considered in relation or in proportion to something else.

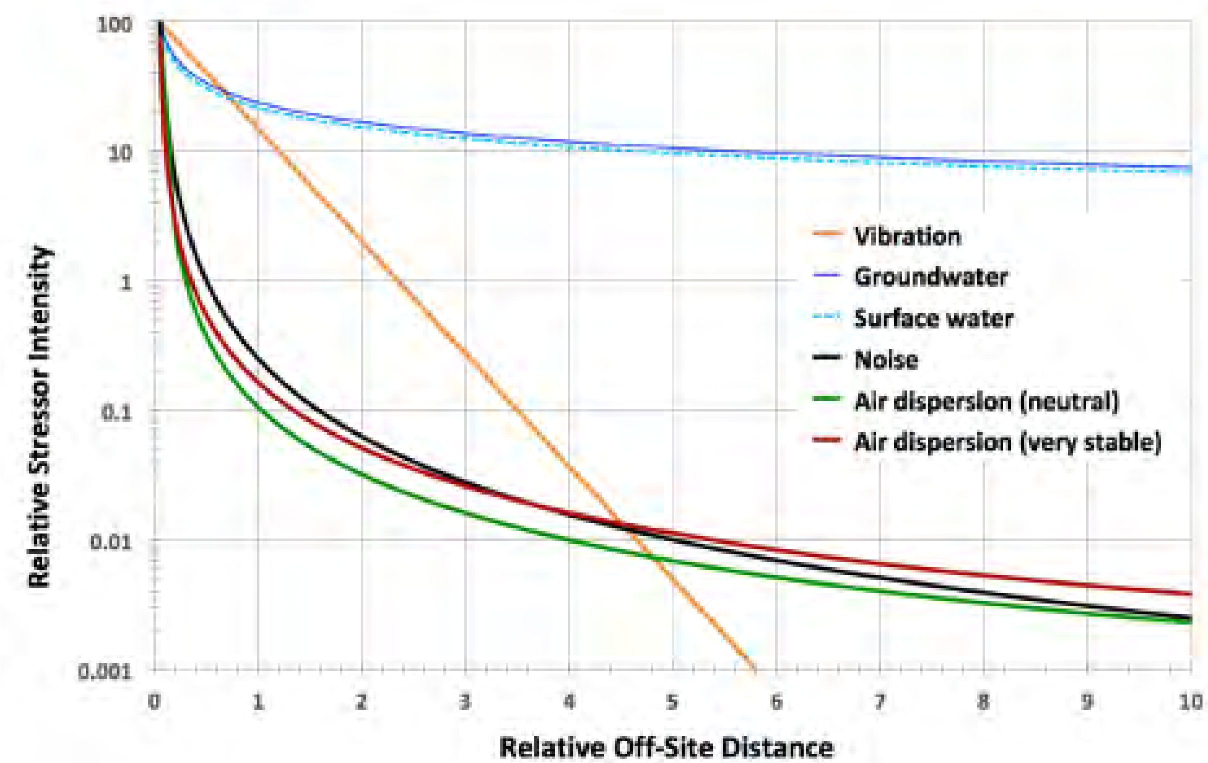

Figure 2.3. A hypothetical illustration of potential attenuation by offsite distance for a range of stressors. The relative distance is the actual distance divided by a considered distance. Developed from material presented in the following sources: Turner (1970), Martin (1976), Domenico and Palaciauskas (1982), Domenico and Robbins (1985), Lamancusa (2000, 2002, 2009), Jirka and Weitbrecht (2005), van Leeuwen et al. (2007), Nicholls (2009), Truty et al. (2019).

2.5 Discussion

Below we provide additional discussion on (1) a comparison of stressors from unconventional and conventional oil and gas development, and (2) current policies limiting chemical usage in oil and gas development to protect public health.

2.5.1 Comparison of stressors from unconventional and conventional oil and gas development

Although definitions of conventional and unconventional OGD may differ across different regulatory and policy landscapes, the majority of OGD in California is often considered conventional, involving vertical drilling at shallower depths into target geologies that hold migrated hydrocarbons. These attributes of development are often considered in contrast to unconventional OGD, which involves horizontal directional drilling in deeper wells to access source rock formations and increasing the permeability of these tight formations using mostly hydraulic fracturing. In addition, unconventional operations are often accompanied with greater masses of material inputs (e.g., water, chemical additives, proppants) and a greater magnitude of liquid and solid waste outputs (e.g., flowback fluids and produced water). It should be noted, however, that hydraulic fracturing that takes place in California often uses fluids (gels) with higher concentrations of well stimulation chemicals than those fluids used in high-volume slick water hydraulic fracturing of source rock in other parts of the United States (Long et al., 2015).

However, many stressors are intrinsic to both conventional and unconventional OGD (Hill et al., 2019; Jackson et al., 2014; Lauer et al., 2018; Stringfellow et al., 2017; Zammerilli et al., 2014). $PM_{2.5}$ and nitrogen oxides emissions result from the use of diesel-powered equipment and trucks. Hazardous air pollutants such as BTEX occur naturally in oil and gas formations, regardless of the type of extraction method employed. Noise pollution, odors, and landscape disruption are inherent to OGD. Investigations in other oil and gas states have noted radioactivity on particles downwind from unconventional oil and gas wells (Li et al., 2020) and in sediment downstream of water treatment plants that treat waste from conventional as well as unconventional oil and gas operations (Burgos et al., 2017; Lauer et al., 2018). Additionally, a recent evaluation of chemical usage during OGD in California found significant overlap in chemical additives used for well stimulation (including hydraulic fracturing) and those used in routine activities, such as well maintenance (Stringfellow et al., 2017).

California has placed policy, regulatory, and scientific emphasis on well stimulation activities, including hydraulic fracturing, matrix acidizing, and acid fracturing. The *2015 Independent Scientific Assessment on Well Stimulation in California*, which focused primarily on well stimulation activities pursuant to Senate Bill 4 (2013), had the following key conclusion: “The majority of impacts associated with hydraulic fracturing are caused by the indirect impacts of oil and gas production enabled by the hydraulic fracturing” (Long et al., 2015). Indirect impacts relevant to human health for the purposes of the study included “proximity to any oil production, including stimulation-enabled production, could result in hazardous emissions to air and water, and noise and light pollution that could affect public health” (Long et al., 2015).

2.5.2 Current chemical use policies

There are examples of restricting chemical usage in oil and gas development in the United States. Under the Safe Drinking Water Act, diesel fuels are prohibited from being used in hydraulic fracturing in the United States unless operators obtain permits under the Class II Underground Injection Control (UIC) program (US EPA, 2014). A review of permitting and oversight by the U.S. EPA in 2017 found no cases of operators applying for permits for use of diesel fuels in hydraulic fracturing (US EPA, 2017). Studies confirm that diesel fuels have not been reported in hydraulic fracturing chemical disclosures in California since 2011, although a report by the U.S. Congress found 26,466 gallons (100,184 liters) of hydraulic fracturing fluids containing diesel fuels were used in California between 2005–2009 (Waxman et al., 2011). Restrictions on diesel fuel use do not apply to non-hydraulic fracturing activities (US EPA, 2016). Diesel fuel (kerosene [CASRN: 8008-20-6]) is used as a component of work-over fluid in operations in the southern San Joaquin Valley that provide produced water for irrigation (Shonkoff et al., 2016).

Effective January 15, 2021, the Colorado Code of Regulations (Colo. Code Regs. § 404-1-437) prohibits the use of 22 specific compounds in hydraulic fracturing fluids because these compounds posed the greatest risks to public health based on toxicity and their mobility and persistence in groundwater (Appendix B, Table B.2). This list was based on hydraulic fracturing compounds identified by Rogers et al. (2015) that posed the greatest risks to public health based on their mobility and persistence in groundwater. Not all chemicals identified by Rogers et al. (2015) were prohibited; polysorbate 80 was not prohibited due to its frequency of use in Colorado and relatively lower risk to human health. It is important to note that these 22 chemicals are prohibited as chemical additives, but not in base fluids, allowing for the reuse and recycling of produced water that may naturally contain these compounds (§ 404-1-437). Seventeen of the 22 prohibited chemicals are used in upstream oil and gas development in California. Colorado House Bill 1348 (2022) provides a model for implementing disclosure requirements for any chemical that may be used in oil and gas production. This enables the public and regulators to evaluate the environmental and public health impacts of these chemicals and to encourage less-toxic alternatives. This bill also includes explicit restrictions on the use of per- and polyfluoroalkyl substances (PFAS).

2.6 Summary

Various chemical and physical stressors are associated with upstream oil and gas development activities, including air pollutants, surface water and groundwater contaminants, vibration, noise, and odors. Communities living near OGD operations may be exposed to combinations of stressors. Chemical stressors include compounds naturally occurring in petroleum reservoirs, such as petroleum hydrocarbons (e.g., BTEX), metals, chemical additives used in the OGD processes, and odorous compounds. Upstream OGD activities, including the use of diesel equipment, trucks and flaring, also emit combustion products that are classified as toxic air contaminants or federally designated criteria air pollutants. Emissions of various volatile organic compounds from upstream oil and gas activities can result in the secondary formation of ground-level ozone, another criteria air pollutant.

Chemical additives are used during routine activities (e.g., well maintenance), as well as during well stimulation (e.g., hydraulic fracturing). Between 2011 to 2018, 630 different chemical additives with CASRN were identified as used in oil and gas operations in California. Of these compounds, 40 (6%) are Prop 65 carcinogens, 70 (11%) are toxic air contaminants, and 38 (6%) are identified for acute or chronic toxicity. While chemical additive disclosure in OGD operations is helpful to identify potential environmental and health hazards, chemical additive use and subsequent concentrations of additives in produced water and flowback varies greatly across time and geographic, geological, and operator space. Additionally, relatively non-toxic chemical additives that are degradable may transform into more toxic or more environmentally persistent compounds.

Physical stressors associated with upstream OGD include noise pollution, artificial light at night (ALAN), radioactive materials, induced seismicity, explosions, and fires. Noise near oil and gas sites has been observed at levels associated with annoyance, sleep disturbance, and cardiovascular disease. Studies focused on OGD show that various sensory stimuli, including ALAN, noise, and vibrations from drilling operations, may contribute to psychosocial stress, anxiety, and depression due to changes in quality of life, and to sleep deprivation and poor physical and mental health. Oil and gas development can also introduce naturally occurring radioactive materials (NORM) to the surface. In addition to physical hazards and safety risks, induced seismicity also contributes to increased psychological responses, including anxiety (Casey et al., 2018), though induced seismicity associated with OGD has not been documented in California.

Finally, the impact of these stressors generally attenuates as distance from the source increases. The degree of attenuation is dependent on the properties of the specific stressor. Therefore, the risks associated with chemical and physical stressors stemming from upstream oil and gas sites may be attenuated by establishing a distance between the oil and gas source and the receptor, whether it be a human receptor or a receptor relevant to human exposure (e.g., a drinking water well). While risk attenuation by distance varies by stressor, all stressors are reduced as the distance between the source and the receptor increases.

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Appendix B.

B.1. Chemical additives used in oil and gas development

Description of chemical additive disclosure databases for upstream oil and gas development

Operators performing well stimulation treatments in California are required to submit chemical usage data to the California Geologic Energy Management Division (CalGEM) (CalGEM, 2020). In this context, well stimulation treatments are defined as hydraulic fracturing and acid well stimulation, but do not include “steam flooding, water flooding, or cyclic steaming and do not include routine well cleanout work, routine well maintenance, routine removal of formation damage due to drilling, bottom hole pressure surveys, or routine activities that do not affect the integrity of the well or the formation” (CalGEM, 2020). Under California Public Resources Code (P.R.C) § 3160 (2023) operators must disclose all chemical components of mixtures, including trade secrets. Individual chemical components are not linked to a chemical mixture; mixtures and their components are listed separately to allow for chemical disclosure while protecting proprietary industry information. Well stimulation chemical data submitted to CalGEM are publicly available for download from the WellSTAR website as the Well Stimulation Disclosure Dataset (CalGEM, 2021).

The South Coast Air Quality Management District (SCAQMD) is the primary air pollution control agency for Orange County and urban portions of Los Angeles, Riverside, and San Bernardino counties (SCAQMD, 2018). The SCAQMD requires oil and gas operators within its jurisdiction to report chemical usage for well drilling, completion, and rework, which includes activities such as hydraulic fracturing, acid fracturing, matrix acidizing, maintenance acidizing, and gravel packing (SCAQMD, 2015a). To date, the SCAQMD is the only known regulatory agency that requires the disclosure of chemical use in conventional oil and gas operations and provides the most complete picture of chemical usage in California. In 2015, SCAQMD updated Rule 1148.2 to dissociate trade names from individual chemical ingredients, bringing reporting in line with well stimulation and hydraulic fracturing disclosure requirements and encouraging additional chemical disclosure.

FracFocus is a national online database of chemical disclosures for hydraulic fracturing operations nationwide and is maintained by the Groundwater Protection Council and Interstate Oil and Gas Compact Commission (Groundwater Protection Council & Interstate Oil and Gas Compact Commission, 2019). Since its founding in 2011, FracFocus has undergone two major revisions, referred to as FracFocus 2.0 (November 2012 to 2016) and FracFocus 3.0 (June 2016 to present). There is overlap in data submissions during transition periods between different versions of FracFocus. Each revision standardized and updated reporting, data validation, and data access. Most notably, the launch of FracFocus 3.0 in 2016 integrated a new “systems approach” to chemical reporting, where chemical ingredients were dissociated from trade names, allowing for increased disclosure while maintaining proprietary information (Groundwater Protection Council & Interstate Oil and Gas Compact Commission, 2019; Trickey et al., 2020). In 2015, California made it mandatory for operators to report chemical usage in hydraulic fracturing operations to FracFocus, before which reporting was voluntary (CalGEM, 2020).

In 2016, the Central Valley Regional Water Quality Control Board (CVRWQCB), under the authority of California Water Code Section 13267, requested chemical disclosures from seven oil and gas operators in the southern San Joaquin Valley that provide produced water for agricultural reuse (CVRWQCB et al., 2021). Initial chemical disclosures were obtained for a period from January 2014 to June 2016 from Deer Creek, Mount Poso, Jasmin, Kern Front, and Kern River oil fields, where enhanced oil recovery (EOR) operations are commonplace. In 2017 and 2018, the CVRWQCB requested two years of additional chemical usage data from both operators and chemical suppliers under the authority of California Assembly Bill 1328 (AB 1328). CVRWQCB staff compiled data on the identities of oil field additives and periodically posted updated lists on their website. Due to concerns surrounding trade secret information, mass and frequency of use data could not be released to the public (CVRWQCB et al., 2021). The combined dataset from the CVRWQCB will be referred to as the AB 1328 dataset in this report. In February of 2021, CVRWQCB and the Food Safety Expert Panel released a draft final report which included a final list of chemical additives from June 2019. This recently updated list was not included in the analysis of chemical additives in Chapter 2.

Key studies of chemical disclosure datasets

Key studies of chemical usage disclosure datasets are summarized in Appendix B, Table B.1. One of the first major studies to examine chemical usage in upstream oil and gas was done by the California Council on Science and Technology (CCST) (2015) as part of an independent scientific assessment of well stimulation treatments in California, pursuant to Senate Bill 4. This study was limited to hydraulic fracturing and well stimulation activities and found major data gaps regarding the disclosure of chemical identities and available toxicological and physicochemical data necessary for assessing chemical hazards and risks. Follow up studies of chemical use in the SCAQMD and the AB 1328 datasets provided similar results regarding chemical disclosure and the overall lack of available chemical characterization (Shonkoff et al., 2016, 2019; Stringfellow et al., 2017). The analysis of chemical usage in hydraulic fracturing by the U.S. EPA (US EPA, 2016) is a valuable resource for nationwide chemical use in hydraulic fracturing, but does not provide in-depth state level analysis of chemical use beyond identifying the top 20 most frequently reported chemicals used in California.

The most recent cross analysis of all available chemical disclosure datasets was done by the CCST and included data from 2011 to the end of 2018 (Shonkoff et al., 2021). The estimated number of chemicals without CASRN is likely an overestimate because chemicals without CASRN cannot be uniquely identified, and due to the timeframe of the study. The CCST study included data from early FracFocus 1.0 and 2.0 submissions for completeness; some chemical additives were only reported in these early submissions. Many of the early studies of the FracFocus database were performed prior to the implementation of FracFocus 3.0 and California laws requiring the decoupling of chemical ingredients from trade names (Cal. Code of Regs Title 14 § 1788, Cal. Pub. Res. Code § 3160). These studies listed numerous proprietary and trade secret formulations that could not be identified (CCST et al., 2015; Stringfellow et al., 2017; US EPA, 2016). Analyses of forms submitted to FracFocus 3.0 in California since 2016 found no valid cases of chemical information withholding (Trickey et al., 2020; Shonkoff et al., 2021); any reported instances of chemical withholding since 2016 were from mislabeled entries. Additionally, the

CCST study did not include the most recent draft report from the CVRWQCB, which updates the AB 1328 dataset with only 18 trade secret chemicals (CVRWQCB et al., 2021), compared to the 80 in the CCST report (Shonkoff et al., 2021).

Table B.1 Key studies examining chemical usage in oil and gas development in California.

Chemical Data Source	Oil and Gas Activity	Timeframe	Region	Findings	Study
FracFocus 1.0	Hydraulic Fracturing	Jan 2011–Feb 2013	Nationwide	20 Most frequently reported chemicals for hydraulic fracturing in California	US EPA (2016)
FracFocus 1.0, 2.0	Hydraulic Fracturing	Jan 2011–May 2014	Statewide	338 chemicals total 228 with CASRN	CCST et al. (2015); Stringfellow et al. (2017)
CalGEM Notices of Intent and Completion Reports	Acidizing treatments	Dec 2013–May 2015	Statewide		
SCAQMD	Acidizing	Jun 2013–Jun 2014	Los Angeles Basin	78 chemicals	
AB 1328 (CVRWQCB)	Enhanced oil recovery (steam flooding)	Jan 2014–Jun 2016	Southern San Joaquin Valley	173 chemicals total 107 with CASRN	Shonkoff et al. (2016)
SCAQMD	Well drilling Well completion Well rework	Jun 2013–Sep 2015	Los Angeles Basin	548 chemicals total 525 chemicals used in routine oil and gas (249 with CASRN) 24% of which also used in hydraulic fracturing in California	Stringfellow et al. (2017)

Chemical Data Source	Oil and Gas Activity	Timeframe	Region	Findings	Study
SCAQMD, CalGEM	Acidizing treatments	Apr 2013–Aug 2015	Statewide	~200 chemicals with CASRN 90 trade secrets	Abdullah et al. (2017)
SCAQMD	Well drilling Well completion Well rework	Jun 2013–Aug 2018	Los Angeles Basin	651 chemicals total 324 with CASRN	Shonkoff et al. (2019)
FracFocus 1.0, 2.0, 3.0; CalGEM; SCAQMD; AB 1328 (CVRWQCB)	Well drilling Well completion Well rework Well stimulation Enhanced oil recovery	2011–2018	Statewide	1,119 chemicals total 630 with CASRN	Shonkoff et al. (2021)
AB 1328 (CVRWQCB)	Enhanced oil recovery (steam flooding)	Up to Jun 2019	Southern San Joaquin Valley	324 with CASRN 18 trade secret	CVRWQCB et al. (2021)

Abbreviations: CASRN – Chemical Abstracts Service Registry Number; SCAQMD – South Coast Air Quality Management District; CalGEM – California Geologic Energy Management Division; AB – Assembly Bill, CVRWQCB – Central Valley Regional Water Quality Control Board.

Table B.2. Chemical additives prohibited in hydraulic fracturing activities in Colorado as of January 15, 2021.

Ingredient Name	**CAS #**
Benzene	71-43-2
Lead	7439-92-1
Mercury	7439-97-6
Arsenic	740-38-2
Cadmium	7440-43-9
Chromium	7440-47-3
Ethylbenzene	100-41-4
Xylene	1330-20-7
1,3,5-trimethylbenzene	108-67-8
1,4-dioxane	123-91-1
1-butanol	71-36-3
2-butoxyethanol	111-76-2
N,N-dimethylformamide	68-12-2
2-ethylhexanol	104-76-7
2-mercaptoethanol	60-24-2
Benzene, 1,1'-oxybis-,tetrapropylene derivatives, sulfonated, sodium salts (BOTS)	119345-04-9
Butyl glycidyl ether	2426-08-6[1]
Quaternary ammonium compounds, dicoco alkyldimethyl, chlorides (QAC)	61789-77-3
Bis hexamethylene triamine penta methylene phosphonic acid (BMPA)	35657-77-3
Diethylenetriamine penta (methylene- phosphonic acid) (DMPA)	15827-60-8
FD&C blue no. 1	3844-45-9
Tetrakis (triethanolaminato) zirconium (IV) (TTZ)	101033-44-7

[1]Originally listed as "8-6-2426" in the text of the Final Draft of the Amended 400 Series Rules.

B.2. Equations relevant to attenuation of stressors

Air emissions

Substances in outdoor (or ambient) air are dispersed by atmospheric advection and diffusion. The magnitude of attenuation by advection/dispersion depends on meteorological parameters that include wind parameters — direction, velocity, and turbulence — and thermal properties that relate to atmospheric stability and mixing depth. The standard models for estimating the time and spatial distribution of point sources of contamination in the atmosphere are the Gaussian statistical solutions of the atmospheric diffusion equation. These models are obtained from the solution of the classical differential equation for time-dependent diffusion in three dimensions. The standard solution for the downwind concentration as discussed by (Turner, 1970) is:

$$C(x,y,z) = \frac{Q}{2\pi\, u\sigma_y\sigma_z}\exp\left(-\frac{y^2}{2\sigma_y^2}\right)\left[\exp\left(-\frac{(z-H)^2}{2\sigma_z^2}\right)+\exp\left(-\frac{(z+H)^2}{2\sigma_z^2}\right)\right] \quad (2.6)$$

Where C(x,y,z) is the contaminant concentration, in g/m^3 at a position x downwind, y crosswind and z vertically from the source; Q is the contaminant source strength, g/s; x is the distance (m) downwind and z is the distance (m) in air above the source; u is the ground-surface wind speed in m/s, H is the height of the release, in m; and σ_y and σ_z are, respectively vertical and horizontal dispersion parameters (in m). Figure B.1 provides an illustration of downwind dispersion processes.

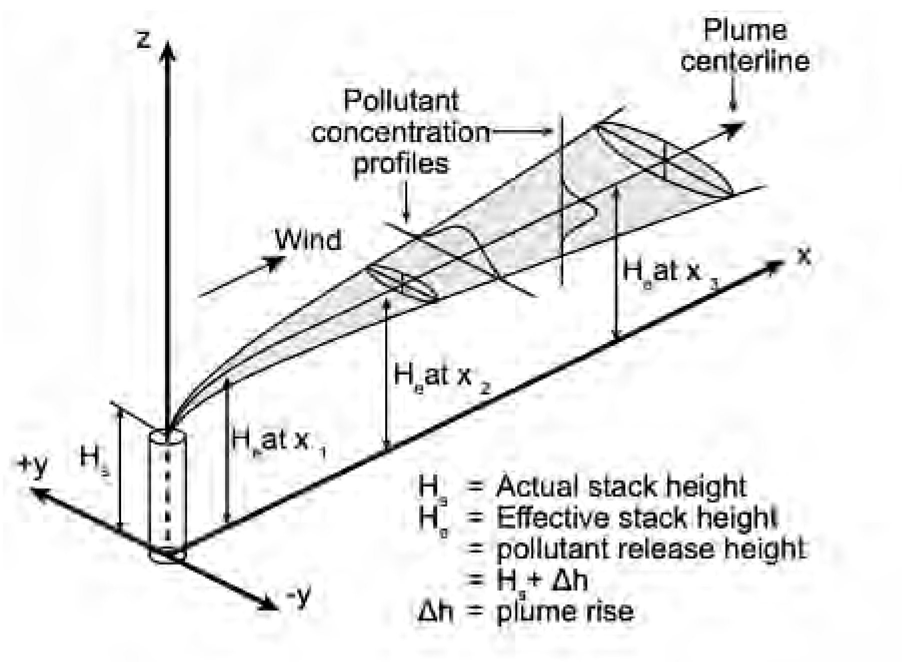

Figure B.1. An illustration of atmospheric dispersion processes and the parameters of equation 2.1. Source: http://en.wikipedia.org/wiki/Atmospheric_dispersion_modeling

In order to assess the attenuation of the concentration downwind from a ground-level release (H=0), along the plume centerline (y=0) and at ground level (z=0), we can simplify Equation 2.1 to the following form:

$$C(x,0,0) = \frac{Q}{2\pi u \sigma_y \sigma_z} \qquad (2.1)$$

The dispersion coefficients σ_y and σ_z are functions of the atmospheric stability class and the downwind distance x from the air pollutant emission source. There are six stability classes used for air dispersion modeling:

1 (or A) = very unstable	4 (or D) = neutral
2 (or B) = moderately unstable	5 (or E) = somewhat stable
3 (or C) = slightly unstable	6 (or F) = stable

The magnitude of the σ_y and σ_z dispersion coefficients can be estimated using the empirical equations reported by (Martin, 1976). The turbulent mixing under stability category 1 provides the best atmospheric dilution, whereas the stable air and low mixing depth fund in stability condition 6 provides the least amount of dilution with distance.

We use equation 2.1 with both neutral (1) and stable (6) conditions to calculate the attenuation profile provided in **Figure 2.3**.

Surface water releases

Releases of chemical substances to surface water are dispersed and impacted by flow rates, advection/diffusion-based dispersion, deposition to sediments, and transformation processes. Mathematical models are frequently used to estimate the distribution of a chemical in surface water after a spill or from a continuous release. In van Leeuwen and Vermeire (2007), the authors describe the models as ranging from a simple equation to highly sophisticated models for evaluating an entire river/lake system. Jirka and Weitbrecht (2005) have described and modeled the hydrodynamics of an effluent continuously discharging into a receiving water body. In their description there is a “near-field” region close to the source where source characteristics determine initial dispersion. Once the plume has become well mixed, far-field conditions are attained. In this region the water flow, eddy diffusivity, and surface water dimensions will control trajectory and dilution of the well dispersed plume. For our comparison of attenuation in different media, we focus on this far-field behavior. In this region, Jirka and Weitbrecht (2005) suggest a simple model to assess the change in concentration with distance x. In this formulation, the maximum pollutant concentration c_{max} (g/m^3) as a function of distance x (m) along the flow direction is given by:

$$c_{max} = 2\frac{Q_{c0}}{h\sqrt{4\pi E_y U x}} \qquad (2.2)$$

where Q_{co} is the pollutant mass flux of the source (g/s), h is the depth of the surface water (m), E_y is the lateral turbulent diffusivity (m^2/s), and U is the average flow of the surface water (m/s). The factor 2 on the right-hand side signifies the reflection effect of the impermeable riverbank. Jirka and Weitbrecht (2005) estimate Ey as function of h and U.

$$E_y = 0.00525\ Uh \tag{2.3}$$

The processes represented in this model are illustrated in Figure B.2. We use this model to examine the expected trend of dilution with distance in surface waters and to develop the profile for surface water attenuation provided in **Figure 2.3**. Compared to other off-site transport processes, dilution in surface water is much slower and follows a $1/\sqrt{x}$ trend rather than the more rapid $1/x^2$ or exponential attenuations of other stressors.

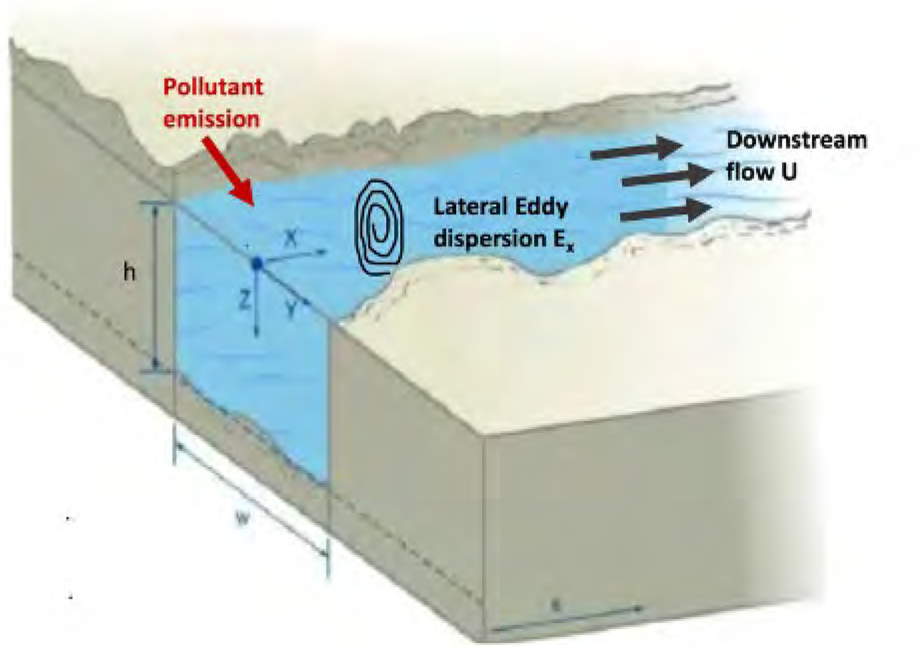

Figure B.2. An illustration of first-order pollutant transport and attenuation in surface water.

Subsurface releases (groundwater)

In order to estimate the dilution of contaminants in groundwater, we make use of a contaminant plume analysis model described by Domenico and Robbins (1985), which is an extension of an earlier model posed by Domenico and Palciauskas (1982). The latter model has been used by the U.S. EPA (1985) to assess off-site transfers of contaminants at hazardous waste sites. Both of these models have been widely used and cited.

Domenico and Robbins (1985) developed an analytical expression for contaminant transport from a finite source in a continuous flow regime. They adapted this model to solving the problem of the extended pulse approximation to the continuous finite source problem. Their analytical solution is derived from solving the time-dependent, three-dimensional dispersion/advection mass balance equation that applies to the transport of contaminants in an aquifer in the absence of transformation processes.

Figure B.3 illustrates the leaching of contaminants from an oil/gas site down through the unsaturated zone and into the saturated zone where transport is lateral. This figure provides a conceptual diagram of the model we use for off-site transport in the saturated zone. For a pulse of contaminant introduced at concentration C_0 to ground water at x = 0 across the width Y and to a depth Z, Domenico & Robbins (1985) have shown that the solution to the dynamic mass-balance equations for the contaminant plume centerline is:

$$C\,(x,y,z,t) =$$

$$C(x,0,0,t) = \frac{C_0}{2}\ \mathrm{erfc}\left[\frac{x - v_c t}{2\sqrt{D_{lc} t}}\right] \times \mathrm{erf}\left[\frac{Y}{4\sqrt{D_{tc} x / v_c}}\right] \times \mathrm{erf}\left[\frac{Z}{4\sqrt{D_{tc} x / v_c}}\right] \tag{2.3}$$

where v_c is the is the mean flow velocity of the contaminant in the aquifer, m/d; D_{lc} and D_{tc} are the longitudinal (lc) and transverse (tc) macro-dispersion coefficients for a contaminant species in the saturated zone water, m^2/d; efrc is the complementary error function; and erf the standard error function.

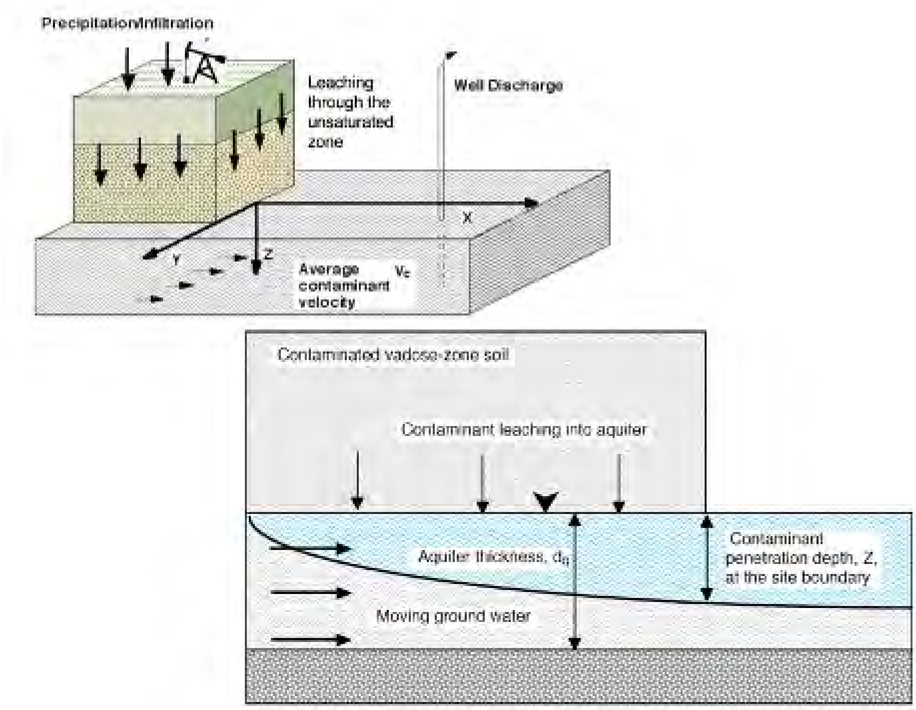

Figure B.3. Conceptual diagram of the model we use for off-site transport in the saturated zone.

Domenico and Robbins (1985) have shown that for a steady state concentration at x << vct for C_0 continuous or for the maximum concentration at any point x along the centerline for a pulse input, Equation 2.3 becomes:

$$C(x,0,0,\text{ at }t_{max}) = C_0 \text{ erf}\left[\frac{Y}{4\sqrt{D_{tc}x/v_c}}\right] \times \text{erf}\left[\frac{Z}{4\sqrt{D_{tc}x/v_c}}\right] \quad (2.4)$$

When the contaminant spread is confined within an aquifer of thickness d_q, then Domenico and Palciauskas (1982) have shown that the appropriate form of equation 2.4 is

$$C(x,0,0,\text{ at }t_{max}) = C_0 \text{ erf}\left[\frac{Y}{4\sqrt{D_{tc}x/v_c}}\right] \times \frac{Z}{d_q} \quad (2.5)$$

We use this equation to determine the relative dilution of contaminants in the subsurface environment as a function of distance x off site. This equation was used to construct the curve in **Figure 2.3** showing the sensitivity of groundwater attenuation to distance. Because of our focus on relative dilution, the shape of the curve is effectively independent of the other parameter values in equation 2.5. Of note, a recent assessment of drinking water wells near upstream oil and gas sites found that long-range transport of pollutants in groundwater is unlikely (Soriano et al., 2020).

Attenuation of sound and noise

As sound propagates through air (or any elastic medium), it causes measurable fluctuations in pressure, velocity, temperature, and density. The transfer of fluctuating pressure through a medium such as air can be visualized as waves of increasing pressure as shown in Figure B.4. The distance between wave peaks is the wavelength. The relationship among the speed of sound, its frequency, and wavelength is

$$v_w = f\lambda \quad (2.6)$$

where v_w is the speed of sound, f is its frequency, and λ is its wavelength.

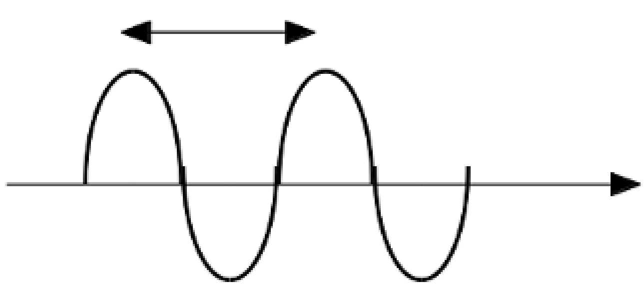

Figure B.4. An illustration of sound waves propagating through a conducting medium.

Sound propagates out from a source as planar waves, along a linear path, or as spherical waves outward on a spherical front. An example of a plane wave is a speaker at the end of a long tube. The sound pressure remains constant as the sound moves along the tube and there is little attenuation of sound intensity. Spherical spreading of waves is observed propagating out from a point source and large medium such as air or water. If we have a point sound source the sound pressure will be constant anywhere on a sphere surrounding the source. The sound pressure will diminish as we travel away from the source. This spherical propagation is illustrated in Figure B.5.

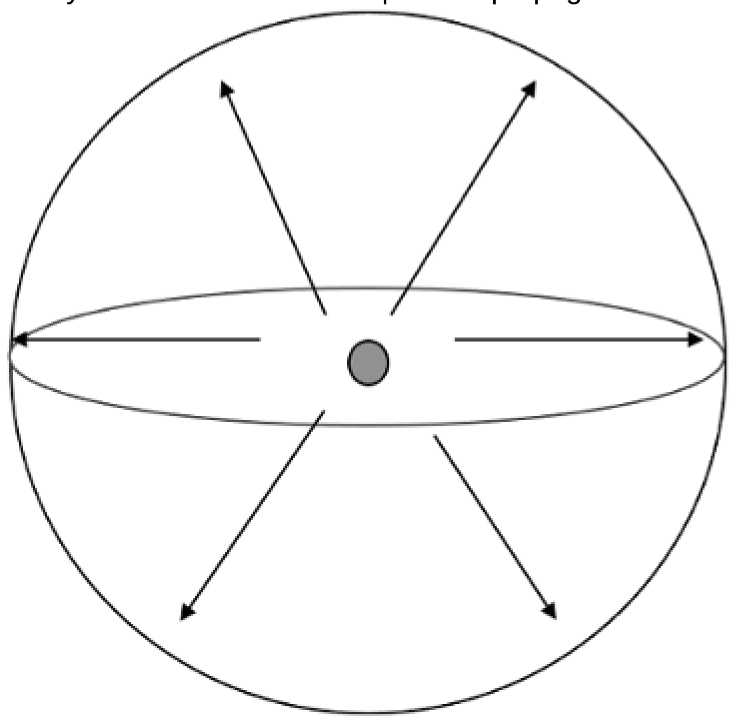

Figure B.5. An illustration of the propagation of sound intensity outward from the source on the surface of a sphere.

Conservation of energy requires that the sound power P_0 in watts (W) at the source is conserved over the surface of the expanding sphere such that the sound intensity I in (W/m^2) follows the relationship (Lamancusa, 2000):

$$P_0 = 4\pi r^2 I(r) \qquad (2.7)$$

Or

$$I(r) = P_0/[4\pi r^2] \qquad (2.8)$$

An alternate and commonly used scale for measuring sound intensity is the decibel (dB) scale. In this scale, the threshold of hearing is assigned a sound level of 0 dB; this sound corresponds to an intensity of $1x10^{-12}$ W/m^2. To calculate dB intensity at any other intensity, one takes the logarithm of the ratio of the observed intensity to the 0 dB intensity of $1x10^{-12}$ W/m^2 and multiplies this logarithm by 10. So, for example, a sound intensity of $1x10^{-8}$ W/m^2, is equivalent to 40 dB.

Sound intensity measured in W/m^2 will attenuation as $1/r^2$, whereas sound intensity in dB will attenuate linearly from the source because dB are measured on a logarithmic scale.

In a real atmosphere, sound (and noise) propagation "deviates from spherical due to a number of factors, including absorption of sound in air, non-uniformity of the propagation medium due to meteorological conditions (refraction and turbulence), and interaction with an absorbing ground and solid obstacles (such as barriers)" (Lamancusa, 2000). So in actual situations it is possible to get additional attenuation. But our interest here is in the general pattern and bounding estimates.

Attenuation of vibrations

Equipment and oil/gas recovery operations generate vibrations, which may or may not be associated with off-site transfer of noise. At oil/gas operations, vibrations travel to surrounding buildings and homes through the ground. Vibrations are described by the same source-path-receiver model as sound (Lamancusa, 2002). The source is a mechanical or fluid disturbance, generated internally by mechanical equipment. The path is the airborne, structural, or subsurface route by which the vibration is transmitted to the receiver. The receiver is a residence or other building, which provides the responding system, generally having many resonant frequencies that can potentially be excited by vibration frequencies generated by the source.

In a detailed numerical assessment of ground vibrations induced by gas and oil well drilling, Truty et al. (2019) have developed a method based on measurements of ground vibrations induced by a specific type of drilling system at a reference site. Nicholls (2009) reports that vibrations in soil (or rock) are attenuated exponentially based on the attenuation factors of soil (rock) and follow relationship of the form:

$$V_{ac} = a \exp(-bx) \qquad (2.9)$$

Where V_{ac} is the vibration intensity expressed as peak particle velocity (PPV) in m/s and a and b are empirical parameters, and x is the distance from the vibration source. The parameter a reflects intensity at the source and b expresses the capacity of the rock/soil to absorb vibration energy.

Nicholls (2009) presented the results of vibration monitoring during different drilling activities at a number of sites. The Nicholls data sets were typically gathered at distances of between 5 m (16 ft) and 50 m (164 ft) from the drilling rig. It was noted that, for some activities, at a distance of 50 m (164 ft), the vibration was deemed negligible. The presented data points to the possibility of a significant drop in vibration intensity occurring at or about 15 m (49 ft) from the drilling rig. Figure B.6 shows the exponential regression developed by Nicholls (2009) for their collected data. The dots are observations and the fitted line is $V_{ac} = 3.0466 \exp(-0.062x)$

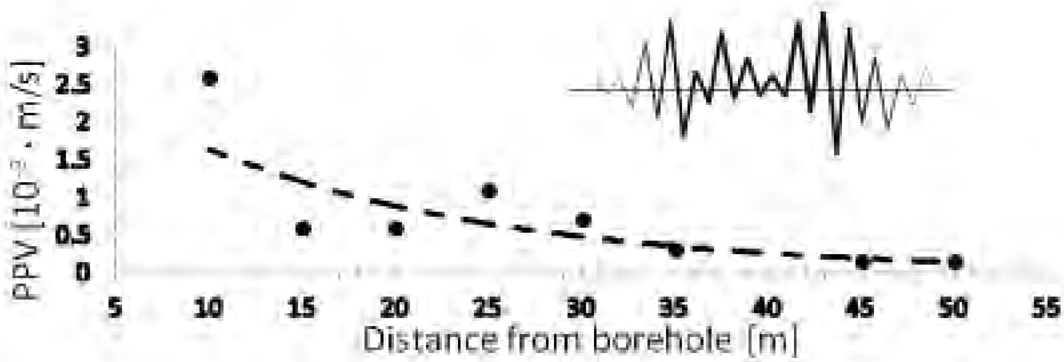

Figure B.6. An illustration of the exponential decay of vibration acceleration from oil and gas operations as a function of distance from the source. Source: Nicholls (2009).

CHAPTER THREE

Peer-Reviewed Epidemiological Literature Evaluating Upstream Oil and Gas Development

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Figures

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3.0. Abstract

A large body of epidemiologic studies has evaluated the relationship between oil and gas development (OGD) and adverse health outcomes. Seventy-two peer-reviewed studies published online between January 1, 2009, and July 15, 2023, were conducted in the United States and Canada. The most studied adverse health outcomes related to OGD are perinatal outcomes (n=25 studies) and respiratory outcomes (n=11). Six studies were conducted in California (not including national studies that included California) and evaluate perinatal outcomes (n=3), respiratory outcomes (n=2), and migraine headaches (n=1).

Epidemiologic studies in the United States and Canada provide evidence that human populations residing closer to OGD, in communities with higher density of OGD and higher production volume of oil and gas, are at increased risk of adverse health impacts compared to those living farther away or in less dense or lower production areas. The relationship between upstream OGD and health is strongest for adverse perinatal and respiratory outcomes, and the Scientific Advisory Panel ("Panel") concludes with a high level of certainty that there is a causal relationship between close geographic proximity to OGD and adverse perinatal and respiratory outcomes. For other health outcomes there remains a paucity of studies, and therefore more research is needed to evaluate the consistency of relationships.

Studies conducted in California observed associations between upstream OGD and diagnosed asthma, reduced lung function, and reduced fetal growth at distances up to 1 km (0.62 miles or 3,281 ft) and beyond, and assessed exposure to OGD using well distance, density, and production volume near participant homes. In particular, two California studies also focused on urban/rural differences in adverse birth outcomes and found stronger associations between OGD and adverse fetal growth outcomes in rural areas. Findings have been consistent across multiple epidemiologic studies that were conducted using different methodologies, in different locations, with diverse populations, and during different time periods. In general, studies within and outside of California have handled confounding, or unmeasured factors that might bias results, using appropriate statistical methods. Despite constraints inherent in environmental epidemiology, specifically, the reliance on observational study designs and surrogate measures of population-level exposure (such as proximity measures), retrospective cohort and case-control study designs used in most of the published studies have accounted for both spatial and temporal aspects of past exposures, as well as complex exposure scenarios. The surrogates of exposure to OGD, such as proximity, cumulative well density, and production volume, used in many studies are appropriate aggregate measures of the potential chemical, physical, and social stressors and exposure pathways associated with OGD. In summary, studies conducted within and outside California find associations between OGD and adverse health outcomes, particularly for perinatal and respiratory outcomes.

3.1. Introduction

In this chapter, we summarize peer-reviewed epidemiological studies evaluating associations between upstream oil and gas development (OGD) and adverse health outcomes in the United

States and Canada, including but not limited to studies conducted in California. We also discuss how the existing body of epidemiological literature can inform public health rulemaking regarding OGD in California.

Epidemiology is the study of the distribution and determinants of health-related variables in specific populations (US DHHS, 2012). Environmental epidemiology studies seek to assess relationships between exposures to certain chemicals, physical agents, or other hazards and adverse health effects — and measure and characterize the strength of observed relationships (i.e., the exposure-response relationship). Environmental epidemiological studies also examine exposures and health outcomes in real-world settings, as opposed to other study designs (e.g., randomized control trials that assess the effectiveness of drug treatments) that can be used in more controlled, clinical settings. While an individual epidemiological study alone cannot establish causality, collectively, a body of epidemiological evidence may support a causal association between an exposure and a health outcome.

In recent years, numerous peer-reviewed epidemiological studies have focused on upstream OGD and adverse health outcomes in the United States and Canada. Previous technical reports examining the public health dimensions of OGD in California have highlighted the need for more health studies specific to California (Long et al., 2015; Shonkoff & Hill, 2019), while noting, "Given the increasingly expansive body of health literature on the topic, consider promulgating health-protective policies based on the existing literature" (Shonkoff & Hill, 2019).

While additional peer-reviewed studies conducted in California have been published since Long et al. (2015) and Shonkoff and Hill (2019), the broader body of literature, including but not limited to studies conducted in California, can inform the California oil and gas public health rulemaking process. Although the geological and regulatory landscape in California may differ from other locations, many chemical stressors (e.g., hazardous air pollutants) and physical stressors (e.g., noise) that can contribute to adverse health outcomes are intrinsic to both conventional and unconventional OGD regardless of geographic location (for more information see Chapter 2, Section 2.5.1).

Furthermore, while California has placed policy, regulatory, and scientific emphasis on well stimulation activities (e.g., hydraulic fracturing, matrix acidizing, and acid fracturing), the 2015 Independent Scientific Assessment on Well Stimulation in California concluded, "The majority of impacts associated with hydraulic fracturing are caused by the indirect impacts of oil and gas production enabled by the hydraulic fracturing" (Long et al., 2015). Indirect impacts relevant to human health for the purposes of the study included, "proximity to any oil production, including stimulation-enabled production, could result in hazardous emissions to air and water, and noise and light pollution that could affect public health" (Long et al., 2015). For these reasons, this chapter includes peer-reviewed epidemiological studies conducted throughout the United States and Canada. California studies are placed within the broader context of the literature, and the body of evidence is considered holistically.

3.2. Approach

Below, we briefly describe our approach to compiling and screening peer-reviewed studies for inclusion in this review.

3.2.1 Scope of review

We identified peer-reviewed epidemiological studies that evaluate upstream OGD and adverse health outcomes in the United States and Canada. Two search engines were used to obtain peer-reviewed studies: the Clarivate Analytics Web of Science database (WOS) advanced search tool and the PSE Healthy Energy Repository for Oil and Gas Energy Research (ROGER)[1] (Clarivate, 2020; PSE Healthy Energy, 2020). The full list of keywords used to search WOS can be found in Appendix C, List S1. Studies housed in ROGER are classified by impact category (e.g., climate, air quality, water quality, health). Studies from the health impact category were evaluated for inclusion in this assessment.

Epidemiological studies included in this review met the following criteria:

- Published in a peer-reviewed journal (print or online).
- Available in English.
- Published online between January 1, 2009, and July 15, 2023.
- Study area in the United States or Canada.
- Evaluated associations between upstream OGD and adverse health outcomes and upstream biomarkers of adverse health outcomes (herein referred to as adverse health outcomes).

Occupational health studies, health risk assessments, and health studies focused on measures of perception, subjective well-being, and quality of life were not included in this review.

The WOS search identified 2,882 peer-reviewed articles published between January 1, 2009, and July 15, 2023. The “Health” folder in PSE’s ROGER database contained 263 citations as of July 15, 2023. When duplicate records between the two databases were considered, 3,024 unique articles remained. Of these, 110 articles were identified as having met our inclusion criteria after review of the title and abstract. After full text review, 38 studies were excluded as they did not meet our inclusion criteria (e.g., studies were review papers, commentaries, non-epidemiological studies). A total of 72 epidemiological studies were included in this assessment (**Figure 3.1**). Studies were categorized by health endpoint and were summarized in tables and figures.

[1] PSE Healthy Energy maintains the Repository for Oil and Gas Energy Research, a database of peer-reviewed studies relevant to assessing the impacts of shale and tight gas development. Studies that focus on oil and gas development in shale regions are also included in this database.

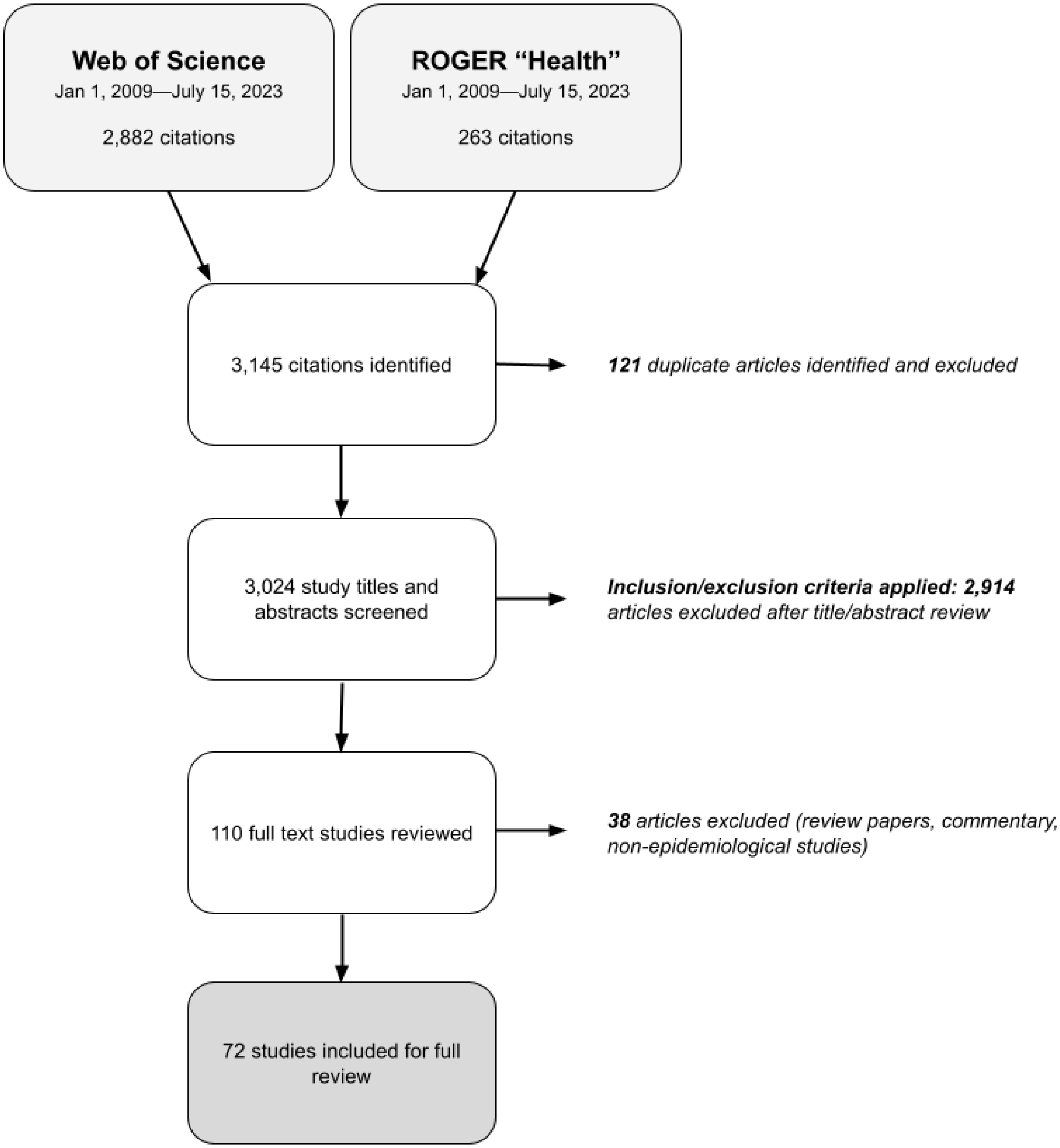

Figure 3.1. Identification of epidemiological studies on the association between oil and gas development and adverse health outcomes.[2]

[2] We applied methods based on the Preferred Reporting Items for Systematic Reviews and Meta-Analyses (PRISMA) to identify studies focused on upstream oil and gas development and health (Sarkis-Onofre et al., 2021).

3.3. Results

We identified 72 peer-reviewed epidemiological studies that evaluated upstream oil and gas development and adverse health outcomes in oil and gas regions in the United States and Canada that were published between January 1, 2009, and July 15, 2023. These studies were conducted in California, Colorado, North Dakota, New York, Ohio, Oklahoma, Pennsylvania, Texas, and West Virginia in the United States, and Alberta and British Columbia in Canada (**Figure 3.2**, top panel). The health outcomes included adverse birth outcomes (perinatal), cancer, respiratory and cardiovascular health, non-outcome specific hospitalizations, mental and behavioral health, additional self-reported health symptoms and health outcomes, and sexually transmitted infections[3] (**Figure 3.2**, bottom panel). Studies included in this review evaluated exposures and health outcomes using health data collected between 1990 and 2021 (**Figure 3.3**).

[3] Studies that evaluate sexually transmitted infections and oil and gas development evaluate dynamics occurring at the community level, rather than at specific upstream oil and gas sites, which are the primary focus of this report. For that reason, these studies are included in overall study counts, but are discussed in more detail in Appendix C.

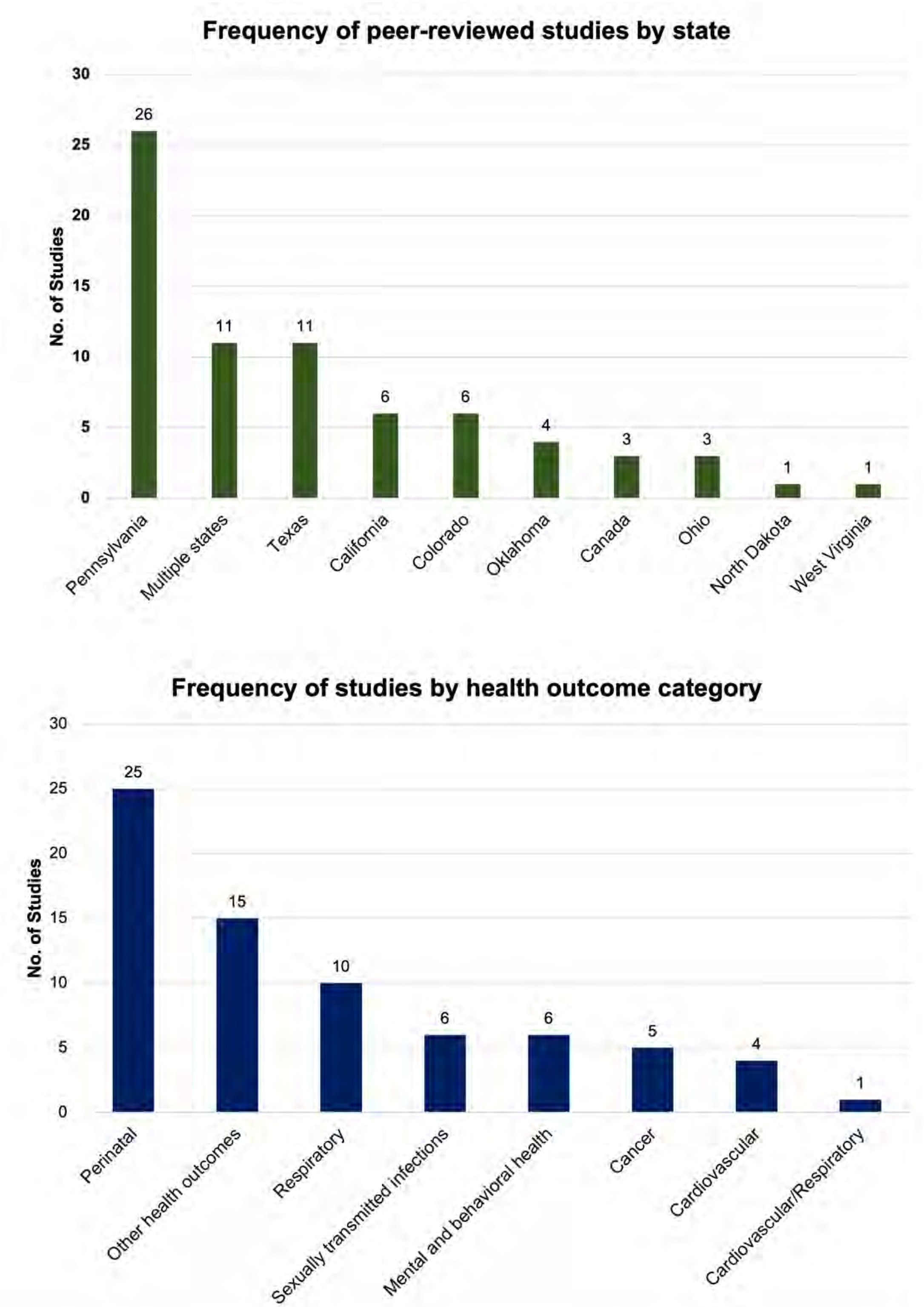

Figure 3.2. Number of peer-reviewed epidemiological studies conducted in each state or region (top panel); number of peer-reviewed epidemiological studies by health outcome category (bottom panel).

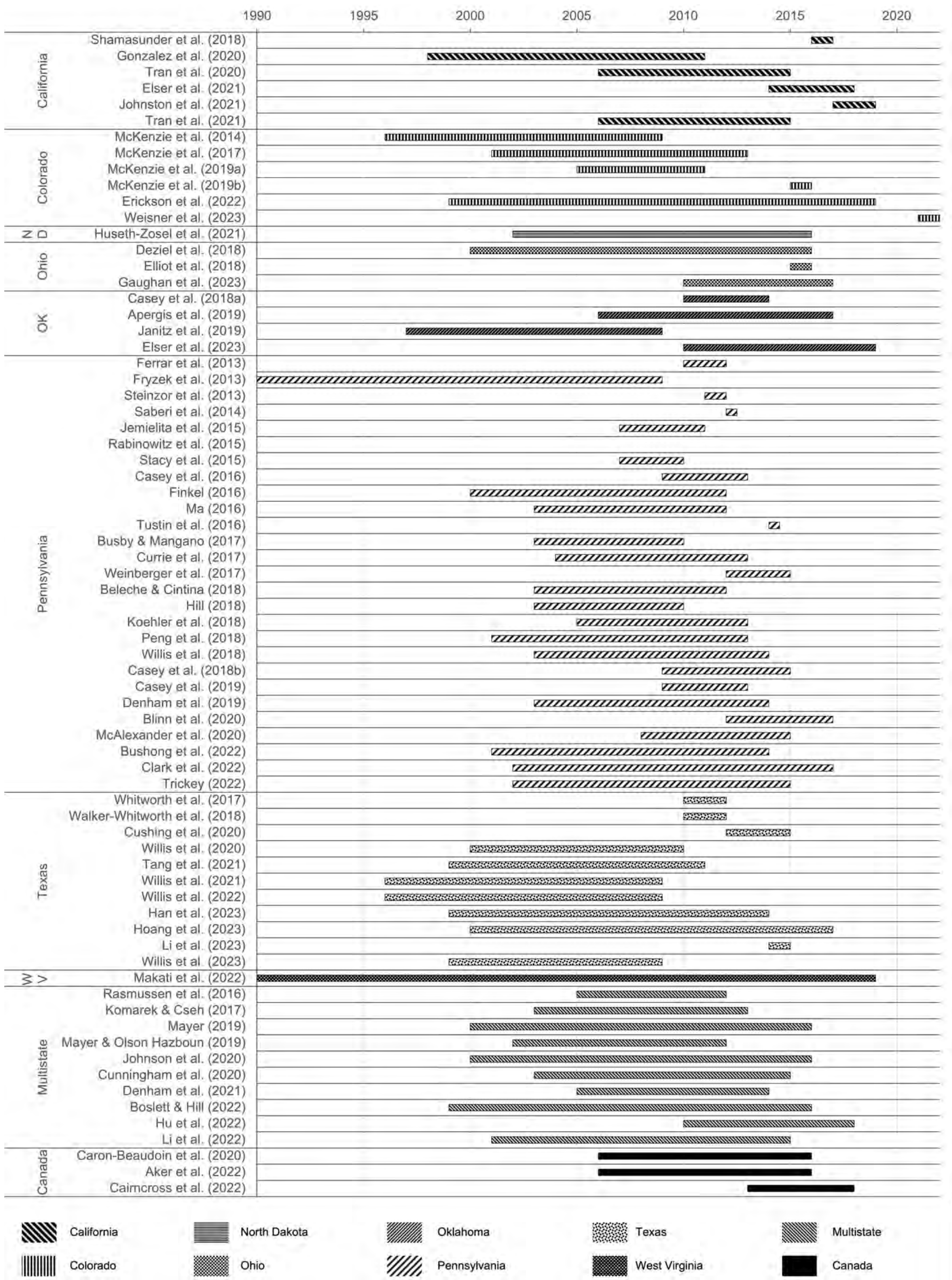

Figure 3.3. Location and timeframe of data used for each epidemiological study. Studies are organized by state, by publication year, and then alphabetically by first author last name.

3.3.1 Surrogates of exposure to upstream oil and gas development

Epidemiological studies included in this report utilize different spatial surrogates of exposure to upstream OGD. This may include assessments of exposure to OGD at the individual level (e.g., linear distance between an individual residence and nearby wells), or at the broader, area level (e.g., the number of wells in the county or zip code where participants reside). The variables that each study considered in aggregate assessments of exposure are summarized in **Table 3.1**.

An approach to assessing exposure to oil and gas wells employed in several of the studies is to quantify oil and gas activities within a given distance of a study participant, or receptor. In these studies, researchers count the number of wells within a specific distance of a study subject's residence (e.g., 1 km, 3,281 ft), or measure the cumulative volume of oil and gas production (i.e., barrels of oil equivalent, BOE) at all wells within a specified distance. One approach to characterize individual exposure to oil and gas activities is inverse-distance weighting (IDW). This measure accounts for the number of wells within a given radius of a residence and the distance (linear or squared) of each well from the residence, while applying greater weights for wells that are closer to the residence. Essentially, the IDW metric captures both proximity to and density of wells near a participant's residence (McKenzie et al., 2014).[4] Some studies use IDW methods that also account for specific phases of well development (e.g., pad preparation, drilling, stimulation, production volume) and other well characteristics (e.g., well depth). Researchers applying IDW or other proximity measures as an indicator of exposure to oil and gas development are typically interested in identifying people with high exposure and comparing their risk of adverse health outcomes to people who were unexposed to wells. It should be noted that in the context of IDW, exposure to wells is approximating the exposure OGD activities that include wells, but also the ancillary equipment and processes that support oil and gas production at these wells.

These proximity-based metrics have the advantages of being scalable (i.e., feasible to apply to large geographic areas or populations), the ability to apply assess exposures retrospectively; and to serve as an aggregate measure of the multitude of physical and chemical stressors potentially emitted from oil and gas development (Deziel et al., 2022a). Aggregation is a particularly useful feature because exposures to multiple hazards are likely, and the dominant stressor may not be known and may differ from well to well. However, the proximity-based metrics are limited in that they do not distinguish exposures to specific hazards, such as benzene and are not designed to estimate exposure levels of specific hazards.

California studies indicate that measuring proximity to oil and gas wells effectively represents exposure to a mix of ambient air pollutants associated with adverse health outcomes, including volatile organic compounds, fine particulate matter, and ozone (Garcia-Gonzales et al., 2019, Gonzalez et al., 2022).

Results presented in Section 3.3.2 and subsections below are organized by health endpoint category. Endpoints are discussed in order of number of available studies, beginning with health endpoints that have the largest number of studies.

[4] McKenzie et al. (2014), the first study to use IDW methods as a surrogate for exposure to upstream oil and gas development, explains, "an IDW well count of 125 wells/mile [1.6 km] could be computed from 125 wells each located 1 mile [1.6 km] from the maternal residence or 25 wells each located 0.2 miles [0.32 km] from the maternal residence."

Table 3.1. Approach to exposure assessment and statistically significant findings by distance for each study. Studies are ordered by sequentially applied the following criteria: alphabetically by state/region, alphabetically by health outcome category, chronologically by year, and alphabetically by first author's last name. For more detail on each study, please see **Tables 3.3–3.8**.

Author (Year)	State	Health outcome category	Distance evaluated (ft)	Distance evaluated (km)	Statistically significant finding for adverse health outcome?	Statistically significant findings for adverse health outcome at ≤1 km (3,281 ft)	Statistically significant findings for adverse health outcome at >1 km (3,281 ft)
Elser et al. (2021)	CA	Other - Migraine headache	32,808	10	No (not for oil and gas findings)	≤1 km (3,281 ft) not specifically evaluated.	No
Gonzalez et al. (2020)	CA	Perinatal	32,808	10	Yes	≤1 km (3,281 ft) not specifically evaluated.	Yes
Tran et al. (2020)	CA	Perinatal	3,281	1	Yes	Yes	Not evaluated.
Tran et al. (2021)	CA	Perinatal	3,281	1	Yes	Yes	Not evaluated.
Shamasunder et al. (2018)	CA	Respiratory	1,500	0.46	Yes	Yes	Not evaluated.
Johnston et al. (2021)	CA	Respiratory and self-reported symptoms	656, 3,281	1	Yes	Yes	Not evaluated.
Aker et al. (2022)	Canada	Mental and behavioral health	8,202, 16,404, 32,808	2.5, 5, 10	Yes	≤1 km (3,281 ft) not specifically evaluated.	Yes

Author (Year)	State	Health outcome category	Distance evaluated (ft)	Distance evaluated (km)	Statistically significant finding for adverse health outcome?	Statistically significant findings for adverse health outcome at ≤1 km (3,281 ft)	Statistically significant findings for adverse health outcome at >1 km (3,281 ft)
Caron-Beaudoin et al. (2020)	Canada	Perinatal	8,202, 16,404, 32,808	2.5, 5, 10	Yes	≤1 km (3,281 ft) not specifically evaluated.	Yes
Cairncross et al. (2022)	Canada	Perinatal	32,808	10	Yes	≤1 km (3,281 ft) not specifically evaluated.	Yes
McKenzie et al. (2017)	CO	Cancer	52,821	16.1	Yes	≤1 km (3,281 ft) not specifically evaluated.	Yes
McKenzie et al. (2019a)	CO	Perinatal	52,800	16.1	Yes	≤1 km (3,281 ft) not specifically evaluated.	Yes
McKenzie et al. (2019b)	CO	Cardio-vascular	52,493	16.1	Yes	≤1 km (3,281 ft) not specifically evaluated.	Yes
McKenzie et al. (2014)	CO	Perinatal	52,800	16.1	Yes	≤1 km (3,281 ft) not specifically evaluated.	Yes
Erickson et al. (2022)	CO	Perinatal	N/A - County-level[1]	N/A - County-level[1]	Yes	N/A - County-level[1]	N/A - County-level[1]
Weisner et al. (2023)	CO	Self-reported symptoms	<5,280–>10,560	<1.61–>3.22	Yes	≤1 km (3,281 ft) not specifically evaluated.	Yes
Mayer (2019)	OH	Other - All-cause mortality	N/A - County-level[1]	N/A - County-level[1]	Yes	N/A - County-level[1]	N/A - County-level[1]
Gaughan et al. (2023)	OH	Perinatal	32,808	10	Yes	≤1 km (3,281 ft) not specifically evaluated.	Yes
Casey et al. (2018a)	OK	Mental and behavioral health	N/A - Distance not specified[2]	N/A - Distance not specified[2]	Yes	≤1 km (3,281 ft) not specifically evaluated.	Yes[3]
Elser et al. (2023)	OK	Mental and behavioral health	N/A - County-level[1]	N/A - County-level[1]	Yes	N/A - County-level[1]	N/A - County-level[1]

Author (Year)	State	Health outcome category	Distance evaluated (ft)	Distance evaluated (km)	Statistically significant finding for adverse health outcome?	Statistically significant findings for adverse health outcome at ≤1 km (3,281 ft)	Statistically significant findings for adverse health outcome at >1 km (3,281 ft)
Apergis et al. (2019)	OK	Perinatal	3,281–65,617	1–20	Yes	Yes	Yes
Janitz et al. (2019)	OK	Perinatal	10,560	3.2	No	≤1 km (3,281 ft) not specifically evaluated.	No
Elliot et al. (2018)	PA	Other - Self-reported symptoms/ outcomes	16,404	5	Yes	≤1 km (3,281 ft) not specifically evaluated.	Yes
Fryzek et al. (2013)	PA	Cancer	N/A - County-level[1]	N/A - County-level[1]	Yes	N/A - County-level[1]	N/A - County-level[1]
Finkel (2016)	PA	Cancer	N/A - County-level[1]	N/A - County-level[1]	Yes	N/A - County-level[1]	N/A - County-level[1]
Clark et al. (2022)	PA	Cancer	6,562, 16,404, 32,808	2, 5, 10	No	≤1 km (3,281 ft) not specifically evaluated.	No
McAlexander et al. (2020)	PA	Cardio-vascular	N/A - Distance not specified[2]	N/A - Distance not specified[2]	Yes	≤1 km (3,281 ft) not specifically evaluated.	Yes[3]
Casey et al. (2018b)	PA	Mental and behavioral health	N/A - Distance not specified[2]	N/A - Distance not specified[2]	Yes	≤1 km (3,281 ft) not specifically evaluated.	Yes[3]
Casey et al. (2019)	PA	Mental and behavioral health	N/A - Distance not specified[2]	N/A - Distance not specified[2]	Yes	≤1 km (3,281 ft) not specifically evaluated.	Yes[3]
Li et al. (2022)	PA	Other - All-cause mortality	N/A - ZIP Code-level[4]	N/A - ZIP Code-level[4]	Yes	N/A - ZIP Code-level[4]	N/A - ZIP Code-level[4]
Makati et al. (2022)	PA	Other - ANCA-associated vasculitis	N/A - County-level[1]	N/A - County-level[1]	Yes	N/A - County-level[1]	N/A - County-level[1]

Author (Year)	State	Health outcome category	Distance evaluated (ft)	Distance evaluated (km)	Statistically significant finding for adverse health outcome?	Statistically significant findings for adverse health outcome at ≤1 km (3,281 ft)	Statistically significant findings for adverse health outcome at >1 km (3,281 ft)
Jemielita et al. (2015)	PA	Other - Non-outcome-specific hospitalizations	N/A - ZIP Code-level[4]	N/A - ZIP Code-level[4]	Yes	N/A - ZIP Code-level[4]	N/A - ZIP Code-level[4]
Denham et al. (2019)	PA	Other - Non-outcome-specific hospitalizations	N/A - County-level[1]	N/A - County-level[1]	Yes	N/A - County-level[1]	N/A - County-level[1]
Ferrar et al. (2013)	PA	Other - Self-reported symptoms/ outcomes	N/A - Distance not specified[2]	N/A - Distance not specified[2]	Statistical significance not assessed.	Statistical significance not assessed.	Statistical significance not assessed.
Steinzor et al. (2013)	PA	Other - Self-reported symptoms/ outcomes	See note[6]	See note[6]	Yes	Yes	See note[6]
Saberi et al. (2014)	PA	Other - Self-reported symptoms/ outcomes	N/A - Distance not specified[2]	N/A - Distance not specified[2]	Statistical significance not assessed.	Statistical significance not assessed.	Statistical significance not assessed.
Rabinowitz et al. (2015)	PA	Other - Self-reported symptoms/ outcomes	3,281–6,562	1–2	Yes	Yes	No
Tustin et al. (2016)	PA	Other - Self-reported symptoms/ outcomes	N/A - Distance not specified[2]	N/A - Distance not specified[2]	Yes	≤1 km (3,281 ft) not specifically evaluated.	Yes[3]
Blinn et al. (2020)	PA	Other - Self-reported symptoms/ outcomes	16,404	5	Yes	≤1 km (3,281 ft) not specifically evaluated.	Yes
Stacy et al. (2015)	PA	Perinatal	52,800	16.1	Yes	≤1 km (3,281 ft) not specifically evaluated.	Yes

Author (Year)	State	Health outcome category	Distance evaluated (ft)	Distance evaluated (km)	Statistically significant finding for adverse health outcome?	Statistically significant findings for adverse health outcome at ≤1 km (3,281 ft)	Statistically significant findings for adverse health outcome at >1 km (3,281 ft)
Casey et al. (2016)	PA	Perinatal	N/A - Distance not specified[2]	N/A - Distance not specified[2]	Yes	≤1 km (3,281 ft) not specifically evaluated.	Yes[3]
Ma (2016)	PA	Perinatal	N/A - ZIP Code-level[4]	N/A - ZIP Code-level[4]	Yes	N/A - ZIP Code-level[4]	N/A - ZIP Code-level[4]
Busby and Mangano (2017)	PA	Perinatal	N/A - County-level[1]	N/A - County-level[1]	Yes	N/A - County-level[1]	N/A - County-level[1]
Currie et al. (2017)	PA	Perinatal	3,281–49,213	1–15	Yes	Yes	Not evaluated.
Hill (2018)	PA	Perinatal	6,562–16,404	2– 5	Yes	≤1 km (3,281 ft) not specifically evaluated.	Yes
Koehler et al. (2018)	PA	Respiratory	3,281, >6,562, >52,800	1, >2, >16.1	Yes	Yes	Yes
Peng et al. (2018)	PA	Respiratory	N/A - County-level[1]	N/A - County-level[1]	Yes	N/A - County-level[1]	N/A - County-level[1]
Willis et al. (2018)	PA	Respiratory	N/A - ZIP Code-level[4]	N/A - ZIP Code-level[4]	Yes	N/A - ZIP Code-level[4]	N/A - ZIP Code-level[4]
Bushong et al. (2022)	PA	Respiratory	N/A - County-level[1]	N/A - County-level[1]	Yes	N/A - County-level[1]	N/A - County-level[1]
Denham et al. (2021)	PA / NY	Cardio-vascular	N/A - County-level[1]	N/A - County-level[1]	Yes	N/A - County-level[1]	N/A - County-level[1]
Trickey (2023)	PA / NY	Cardio-vascular and respiratory	N/A - ZIP Code-level[4]	N/A - ZIP Code-level[4]	Yes	N/A - ZIP Code-level[4]	N/A - ZIP Code-level[4]
Rasmussen et al. (2016)	PA / NY	Respiratory	See note[5]	See note[5]	Yes	≤1 km (3,281 ft) not specifically evaluated.	Yes[4]

Author (Year)	State	Health outcome category	Distance evaluated (ft)	Distance evaluated (km)	Statistically significant finding for adverse health outcome?	Statistically significant findings for adverse health outcome at ≤1 km (3,281 ft)	Statistically significant findings for adverse health outcome at >1 km (3,281 ft)
Hoang et al. (2023)	TX	Cancer	N/A - Spatial cluster analysis[7]	N/A - Spatial cluster analysis[7]	?	N/A - Spatial cluster analysis[7]	N/A - Spatial cluster analysis[7]
Whitworth et al. (2017)	TX	Perinatal	2,640–52,800	0.8–16.1	Yes	Yes	Yes
Walker Whitworth et al. (2018)	TX	Perinatal	2,640	0.8	Yes	Yes	Not evaluated.
Cushing et al. (2020)	TX	Perinatal	16,404	5	Yes	≤1 km (3,281 ft) not specifically evaluated.	Yes
Tang et al. (2021)	TX	Perinatal	3,281–24,606	1–7.5	Yes	Yes	Yes
Willis et al. (2021)	TX	Perinatal	3,281–32,808	1–10	Yes	Yes	Yes
Willis et al. (2022)	TX	Perinatal (Maternal)	3,281–32,808	1–10	Yes	Yes	No
Han et al. (2023)	TX	Perinatal	N/A - County-level[1]	N/A - County-level[1]	Yes	N/A - County-level[1]	N/A - County-level[1]
Willis et al. (2023)	TX	Perinatal	6,562–16,404	5	Yes	≤1 km (3,281 ft) not specifically evaluated.	Yes
Willis et al. (2020)	TX	Respiratory	N/A - ZIP Code-level[4]	N/A - ZIP Code-level[4]	Yes	N/A - ZIP Code-level[4]	N/A - ZIP Code-level[4]
Li et al. (2023)	TX	Respiratory	N/A - Census block group-level[8]	N/A - Census block group-level[8]	Yes	N/A - Census block group-level[8]	N/A - Census block group-level[8]

Author (Year)	State	Health outcome category	Distance evaluated (ft)	Distance evaluated (km)	Statistically significant finding for adverse health outcome?	Statistically significant findings for adverse health outcome at ≤1 km (3,281 ft)	Statistically significant findings for adverse health outcome at >1 km (3,281 ft)
Weinberger et al. (2017)	WV	Other - Self-reported symptoms/ outcomes	3,281	1	Statistical significance not assessed.	Statistical significance not assessed.	Statistical significance not assessed.
Hu et al. 2022	United States	Cardio-vascular	N/A - State-level[9]	N/A - State-level[9]	Yes	N/A - State-level[9]	N/A - State-level[9]
Mayer & Olson Hazboun (2019)	United States	Mental and behavioral health	N/A - County-level[1]	N/A - County-level[1]	No	N/A - County-level[1]	N/A - County-level[1]
Boslett & Hill (2022)	United States	Other – Mortality	N/A - County-level[1]	N/A - County-level[1]	Yes	N/A - County-level[1]	N/A - County-level[1]

[1] N/A - County-level: Not applicable - exposure and outcome assessed at the county level rather than at the individual-level where distance from oil and gas sites can be evaluated.

[2] N/A - Unspecified: Exposure and outcome assessed without specification of distance from oil and gas sites.

[3] Exposure assessment methods reliant on inverse-distance weighting (IDW) often do not specify distance, but it is highly likely that studies reliant on these methods evaluated distances from oil and gas development beyond 1 km (3,281 ft).

[4] N/A - ZIP Code-level: Not applicable - exposure and outcome assessed at the ZIP code-level rather than at the individual-level where distance from oil and gas sites can be evaluated.

[5] Distance for exposure categories not specified in detail. Patients in the highest exposure group lived a median of 19 km (62,336 ft) from closest well vs. 63 km (206,693 ft) for patients in the lowest group.

[6] Residents in “gas patches.” Questionnaire included proximity to three gas facilities (within 1,500 ft [457 m] & outside this radius), including compressor and pipeline stations, gas-producing wells, and impoundment or waste pits. Proximity was assumed to be less than 1 km (3,281 ft), but it is unclear if surveyed residents resided >1 km (3,281 ft).

[7] N/A - Spatial cluster analysis: Studies did not include individual-level evaluations of exposures and outcomes where distance from oil and gas sites can be evaluated.

[8] N/A - Census block group-level: Li et al. (2023) evaluated exposure and outcome at the census block group-level rather than at the individual-level where distance from oil and gas sites can be evaluated.

[9] N/A - State-level: Hu et al. (2022) evaluated exposure and outcome at the state-level rather than at the individual-level where distance from oil and gas sites can be evaluated.

3.3.2 Summary of epidemiologic studies related to specific health endpoints

The following sections summarize the findings from the peer-reviewed epidemiologic literature on the association between upstream OGD and adverse health outcomes. In Section 3.3.2.1, we first discuss the criteria used and the general evidence that supports a causal relationship between oil and gas development and adverse perinatal and respiratory health outcomes. In subsequent sections, we describe the specifics of studies on adverse perinatal outcomes (Section 3.3.2.2) and respiratory outcomes (Section 3.3.2.3). The following sections include other studied health endpoints: mental and behavioral health outcomes (Section 3.3.2.4); cancer (Section 3.3.2.5); cardiovascular outcomes (Section 3.3.2.6); and other health outcomes (Section 3.3.2.7). For all health-endpoint specific sections, we first summarize any findings from studies conducted in California and then those conducted elsewhere in the United States and Canada.

3.3.2.1 Epidemiological studies provide evidence that supports a causal relationship between oil and gas development and adverse perinatal and respiratory health outcomes

Below, we discuss how the body of epidemiological studies on the relationship between upstream OGD and perinatal and respiratory outcomes meets the nine Bradford Hill Criteria for Causation (Hill, 1965; Lucas & McMichael, 2005). The Bradford Hill Criteria are used to evaluate the strength of epidemiological evidence for determining a causal relationship between an exposure and observed effect. After applying these criteria, the Panel concludes with a high level of certainty that there is a causal relationship between close geographic proximity to OGD and adverse perinatal and respiratory outcomes (**Table 3.2**). We have a high level of certainty in the findings from the body of epidemiological studies for perinatal and respiratory health outcomes because of the consistency of results across multiple studies conducted using different methodologies, in different locations, with diverse populations, and during different time periods (see **Table 3.4** below). Most of these studies entail robust analyses, such as longitudinal and case-control study designs that establish temporality based on large sample sizes. These studies also control for potential individual and area-level confounders, apply rigorous statistical modelling techniques, and conduct sensitivity analyses to assess the robustness of effects. A variety of pollutants (e.g., fine particulate matter [$PM_{2.5}$] and toxic air contaminants) and other upstream OGD stressors are associated with these same adverse birth outcomes (Dzhambov & Lercher, 2019; Nieuwenhuijsen et al., 2017; Shapiro et al., 2013) and adverse respiratory effects (Guarnieri & Balmes, 2014), further strengthening the evidence of the link between upstream OGD and these health outcomes. Therefore, the totality of the epidemiological evidence provides a high level of certainty for a causal relationship between residential exposure to upstream OGD and poor perinatal outcomes. Additionally, the epidemiologic evidence base provides a high level of certainty for a causal relationship between residential exposure to upstream OGD and adverse respiratory outcomes.

Oil and gas development and perinatal outcomes

Perinatal outcome studies provide the largest (25 studies)[5] and strongest body of evidence linking upstream OGD exposure during the sensitive prenatal period with adverse health effects. Twenty-four of 25 studies that examine perinatal effects found increased risk of at least one adverse birth outcome in those most exposed to upstream OGD (measured using metrics including, but not limited to proximity, well density, and production volume). Adverse perinatal outcomes, including preterm births, low birth weight, small-for-gestational age births, and congenital malformations, increase the risk of mortality and long-term developmental problems in newborns (Liu et al., 2012; Vogel et al., 2018) as well as longer term morbidity through adulthood (Baer et al., 2016; Barker, 1995; Carmody & Charlton, 2013; Frey & Klebanoff, 2016)**.**

Recent studies in California have reported associations between exposure to upstream OGD and adverse birth outcomes, considering wells under production using conventional methods as well as enhanced oil recovery including cyclic steam injection, steam flooding and water flooding — methods that do not meet the definition of unconventional development (Gonzalez et al., 2020; Tran et al., 2020). Similar findings regarding adverse birth outcomes have been reported for upstream unconventional OGD (UOGD) in California (Tran et al., 2021) and in Colorado, Ohio, Oklahoma, Pennsylvania and Texas (Apergis et al., 2019; Casey et al., 2016; Cushing et al., 2020; Gaughan et al., 2023; Gonzalez et al., 2020; Han et al., 2023; Hill, 2018; McKenzie et al., 2019; Stacy et al., 2015; Tang et al., 2021; Walker Whitworth et al., 2018; Whitworth et al., 2017). Further, a handful of epidemiological studies have explicitly examined potential differences in associations between conventional or unconventional oil or natural gas development and adverse birth outcomes. For example, Apergis et al. (2019) reported statistically significant associations between increased conventional and unconventional well count within 1 km (3,281 ft) of the residence and reductions in infant health index in Oklahoma.

Oil and gas development and respiratory outcomes

Respiratory health outcomes are the second most studied health outcomes in the epidemiological literature examining upstream OGD, with 11 peer-reviewed studies published to date.[6] Two peer-reviewed studies in California found an association between upstream OGD and self-reported and physician-diagnosed asthma, reduced lung function, and self-reported acute respiratory symptoms (e.g., recent wheeze) (Johnston et al., 2021; Shamasunder et al., 2018). Nine studies in other oil and gas regions (New York, Pennsylvania, and Texas) reported an association between upstream OGD and asthma exacerbations, asthma hospitalizations, and other respiratory symptoms or outcomes (Bushong et al., 2022; Koehler et al., 2018; Li et al., 2023; Peng et al., 2018; Rabinowitz et al., 2015; Rasmussen et al., 2016; Trickey et al., 2023; Willis et al., 2018, 2020). Many criteria air pollutants (e.g., $PM_{2.5}$, ozone, nitrogen oxides) and toxic air contaminants emitted from upstream OGD have a well-established body of scientific literature

[5] Apergis et al. (2019); Busby and Mangano (2017); Caron-Beaudoin et al. (2020); Cairncross et al. (2022); Casey et al. (2016); Currie et al. (2017); Cushing et al. (2020); Gonzalez et al. (2020); Erickson et al. (2022); Hill (2018); Janitz et al. (2019); Ma (2016); McKenzie et al. (2014, 2019); Stacy et al. (2015); Tang et al. (2021); Tran et al. (2020, 2021); Walker Whitworth et al. (2018); Whitworth et al. (2017); Willis et al. (2021); Willis et al. (2022).
[6] Bushong et al. (2022); Johnston et al. (2021); Koehler et al. (2018); Peng et al. (2018); Rabinowitz et al. (2015); Rasmussen et al. (2016); Shamasunder et al. (2018); Willis et al. (2018, 2020).

indicating that exposure to these pollutants causes an increased risk of development and exacerbation of respiratory disease (Bolden et al., 2015; Ferrero et al., 2014). While most studies did not evaluate both conventional and unconventional OGD, Willis et al. (2020) found that both conventional and unconventional natural gas development at the ZIP code-level were associated with pediatric asthma hospitalizations in Texas.

Table 3.2. Application of the Bradford Hill Criteria for Causation to the peer-reviewed epidemiological literature on the relationship between oil and gas development and adverse perinatal and respiratory health outcomes.

Criteria for causation (Bradford-Hill)	Description of criteria	Perinatal health studies	Respiratory health studies
Strength of Association	Environmental studies commonly report modest effects sizes (i.e., relative to active tobacco smoking or alcohol consumption). A small magnitude of association can support a causal relationship; a larger association may be more convincing.	Reported effect sizes are in ranges similar to other well-established environmental reproductive and developmental hazards, such as $PM_{2.5}$ (Dadvand et al., 2013; Li et al., 2020a). Some studies, particularly those in California, have found stronger effect estimates for upstream OGD exposures among socially marginalized groups (e.g., Cushing et al., 2020; Gonzalez et al., 2020; Tran et al., 2020, 2021).	Reported effect sizes are in ranges similar to other well-established environmental respiratory hazards. For example, effect sizes in reductions in lung function by Johnston et al. (2021) are similar in magnitude to reductions in lung function associated with secondhand smoke exposure among women (Eisner, 2002) and reductions in lung function among adults living near busy roadways (e.g., Kan et al., 2007).
Consistency	Consistent findings observed by different people in different places with different samples strengthens the likelihood of an effect.	Adverse birth outcomes have been observed in multiple studies using multiple methods in different populations at different times and locations (e.g., California, Canada, Ohio, Oklahoma, Pennsylvania, Colorado, Texas). While there is some variation in findings by specific perinatal outcomes, the overall body of evidence is highly consistent in supporting the association between upstream OGD and adverse perinatal outcomes.	Various respiratory health outcomes are evaluated in the literature. For asthma — the most commonly studied respiratory health outcome — studies across California, Pennsylvania, and Texas consistently show an association between upstream OGD and asthma-related metrics (asthma prevalence, exacerbations, pediatric hospitalizations) (e.g., Koehler et al., 2018; Li et al., 2023; Rasmussen et al., 2016; Shamasunder et al., 2018; Willis et al., 2018, 2020).

Criteria for causation (Bradford-Hill)	Description of criteria	Perinatal health studies	Respiratory health studies
Specificity	Causation is likely if there is no other likely explanation.	All peer-reviewed birth outcome studies included in our review controlled for other potential confounders by accounting or adjusting for other individual-level or area-level factors (e.g., other air pollution sources, neighborhood socioeconomic status) in the analysis (e.g., Casey et al., 2016; Gaughan et al., 2023; McKenzie et al., 2014, 2019; Tran et al., 2020, 2021; Willis et al., 2023). Other studies applied statistical modeling approaches such as difference-in-differences that account for temporal and spatial trends that may confound observed effects (e.g., Willis et al., 2021).	Most respiratory health studies have controlled for other potential explanatory or confounding factors by accounting or adjusting for other individual-level (e.g., smoking status) or area-level factors (e.g., other air pollution sources) in the analysis (Johnston et al., 2021; Koehler et al., 2018; Peng et al., 2018; Rabinowitz et al., 2015; Rasmussen et al., 2016; Willis et al., 2020; Willis et al., 2018), or in the study design, such as utilizing a difference-in-difference methodology (Peng et al., 2018; Willis et al., 2018).
Temporality	Exposure precedes the disease.	Most birth outcomes studies have proper temporal alignment between exposure and outcome and use a retrospective cohort, case control or other study design that allows retroactive assessment of exposures to OGD occurring before the onset of disease. They do not consider exposure that occurred at the time of disease or oil and gas wells drilled after the disease.	Some respiratory health studies do not allow for assessments of exposure that predate disease. However, of the studies with the proper temporal alignment (e.g., Johnston et al., 2021; Koehler et al., 2018; Peng et al., 2018; Rasmussen et al., 2016; Willis et al., 2018), authors report statistically significant associations between OGD and oral corticosteroid medication orders, asthma hospitalizations, and asthma-related emergency department visits.
Biological Gradient (Dose-Response)	Greater exposure leads to a greater likelihood of the outcome.	Some studies have found dose-response relationships based on oil and gas production volume categories or metrics of inverse distance weighting and/or oil and gas well density in California and elsewhere (Casey et al., 2016; McKenzie et al., 2014, 2019; Tang et al., 2021; Tran et al., 2020, 2021).	Larger reductions in lung function observed with decreased distance from active oil development sites (Johnston et al., 2021).

Criteria for causation (Bradford-Hill)	Description of criteria	Perinatal health studies	Respiratory health studies
Plausibility	The exposure pathway and biological mechanism is plausible based on other knowledge.	Individual health-damaging chemical pollutants are well-understood to be emitted from upstream OGD (e.g., $PM_{2.5}$, benzene) and established as contributing to increased risk for the same adverse perinatal outcomes observed in the epidemiology studies. Stressors associated with upstream OGD (e.g., psychosocial stress; Casey et al., 2019) can also contribute to increased adverse perinatal outcomes.	Many air pollutants associated with upstream OGD are well-known to contribute to respiratory morbidity and mortality, including exacerbations of existing respiratory conditions (Guarnieri & Balmes, 2014).
Coherence	Causal inference is possible only if the literature or substantive knowledge supports this conclusion.	In particular, the body of peer-reviewed literature is converging towards singular directions for adverse perinatal outcomes.	The body of peer-reviewed literature points in a singular direction for adverse respiratory health outcomes.
Experiment	Causation is a valid conclusion if researchers have seen observed associations in prior experimental studies.	N/A - Human population-based experimental studies are not available due to ethical issues.	N/A - Human population-based experimental studies are not available due to ethical issues.

Criteria for causation (Bradford-Hill)	Description of criteria	Perinatal health studies	Respiratory health studies
Analogy	For similar programs operating, similar results can be expected to bolster the causal inference concluded.	Pollutants well known to be emitted during upstream OGD including benzene, toluene and 1,3-butadiene are listed as reproductive or developmental toxicants under Proposition 65 and thus are recognized as such by the State of California (CA EPA OEHHA, 2021). EPA's current Integrated Science Assessments conclude that the evidence is suggestive of, but is not sufficient to infer, a causative relationship between birth outcomes, including preterm birth and low birth weight, and $PM_{2.5}$ and long-term ozone exposures (US EPA, 2019, 2020). Additionally, increased stress during pregnancy can alter fetal growth and length of gestation (Fink et al., 2012).	The U.S. EPA's current Integrated Science Assessments of particulate matter and tropospheric ozone conclude that there is a causal relationship between respiratory outcomes, including asthma, and short-term ozone exposure. There is also likely a causal relationship between respiratory outcomes, including asthma, both short- and long-term $PM_{2.5}$ exposure, and long-term ozone exposure (US EPA, 2019, 2020).

3.3.2.2 Perinatal outcomes

Perinatal outcomes are the most common health outcomes evaluated in the peer-reviewed literature in the context of oil and gas development. Twenty-five studies examine the association between upstream oil and gas development and perinatal outcomes (**Table 3.3**). Three studies were conducted in California (described directly below; Gonzalez et al., 2020; Tran et al., 2020, 2021) and 22 studies were conducted in other oil and gas regions, including Colorado (McKenzie et al., 2014, 2019; Erickson et al., 2022), Ohio (Gaughan et al., 2023); Oklahoma (Apergis et al., 2019; Janitz et al., 2019), Pennsylvania (Busby and Mangano, 2017; Casey et al., 2016; Currie et al., 2017; Hill, 2018; Ma, 2016; Stacy et al., 2015), and Texas (Cushing et al., 2020; Han et al., 2023; Tang et al., 2021; Walker-Whitworth et al., 2018; Whitworth et al., 2017; Willis et al., 2021, 2022, 2023). These studies evaluate potential exposures and perinatal outcomes over more than two decades, from 1996 to 2019.

Below we first present studies conducted in California, and then discuss findings by specific perinatal health endpoint, including preterm birth, low birth weight, term birth weight, small for gestational age, congenital malformations, congenital heart defects, neural tube defects and oral clefts, infant health index, low Apgar score, fetal death, and maternal outcomes including high-risk pregnancy and gestational hypertension and eclampsia.

Perinatal outcome studies conducted in California

Three California studies evaluated the associated upstream OGD and perinatal outcomes (preterm birth, low birth weight, term birth weight, small for gestational age) (Gonzalez et al., 2020; Tran et al., 2020, 2021).[7] These studies focus on exposures and perinatal outcomes between 1998 and 2015.

Gonzalez et al. 2020

Gonzalez et al. (2020) conducted a case-control study to evaluate the association between exposure to oil and gas wells and preterm birth risk in the San Joaquin Valley between 1998 and 2011. In this type of study, researchers compare the exposure to upstream OGD between two groups that differ by the health outcome of interest (in this case, preterm birth). The authors assessed exposure using an inverse-distance squared metric of wells in pre-production and active wells within 10 km (6.2 miles) of maternal residence. For each pregnancy, the authors assessed exposure separately for each trimester, then categorized exposure into four bins: unexposed, low, medium, and high exposure. In statistical analyses, the authors compared unexposed births with births that had high exposure. The authors statistically controlled for maternal age, education, race/ethnicity, parity, prenatal care, insurance provider, neighborhood-level poverty, and birth year. Furthermore, the authors divided preterm birth cases into three categories based on gestational age: 20–27 weeks (very early preterm births), 28–31 weeks (early), and 32–36 (moderate). The authors found statistically significantly higher risk of early preterm birth (28–31 weeks) with high exposure to wells compared to unexposed births. In analyses stratified by maternal race/ethnicity and maternal education, the risk was confined to and heightened among

[7] Outcomes are defined and studies are discussed in detail in subsections below.

early preterm births to Hispanic and non-Hispanic Black mothers, and to mothers with 12 or fewer years of education attainment. The results were robust to sensitivity analyses testing assumptions in the exposure assessment and models, as well as accounting for co-exposure to traffic-related pollutants. In a secondary analysis, Gonzalez et al. (2020) found evidence of significantly higher $PM_{2.5}$ and coarse particulate matter (PM_{10}) concentrations at monitors close to drilling sites compared to "unexposed" monitors located farther away. These authors did not aim to precisely estimate specific impacts of drilling or operating wells on concentrations of $PM_{2.5}$ or PM_{10}. Rather, they aimed to determine whether there was an observable increase in concentrations of these pollutants using ground-based monitors, establishing a plausible etiologic pathway from residential proximity to wells to elevated preterm birth risk. In a follow-up study using a more robust study design, the same authors corroborated the findings of marginal increases in $PM_{2.5}$ and PM_{10} concentrations downwind of drilling sites and active wells (Gonzalez et al., 2022).

Tran et al. 2020

Tran et al. (2020) undertook a retrospective cohort study of 2,918,089 births from 2006 to 2015 among mothers living within 10 km (6.2 miles) of at least one production oil and gas well in the Sacramento Valley, San Joaquin Valley, South Central Coast, and South Coast Air Basins to assess the association between exposure to active oil and gas productive and inactive oil and gas wells and adverse perinatal outcomes. The authors defined exposure as residing within 1 km (3,281 ft) of at least one active or inactive oil and gas well at time of delivery. The authors further defined exposure to active wells using the cumulative volume of oil and gas production (in barrels of oil equivalent, or BOE) at all active wells within 1 km (3,281 ft) during pregnancy. Exposure to inactive wells was characterized as the count of inactive wells within 1 km (3,281 ft) of the residence during pregnancy. Associations between proximity to inactive wells were found to be null. However, results showed that mothers living in rural areas and within 1 km (3,281 ft) of at least one active oil and gas well had higher odds of impaired fetal growth. Exposure to higher production volumes in rural areas was associated with a significantly higher odds of low birth weight (LBW), small-for-gestational age (SGA) births as well as lower average birth weight. Associations with LBW and SGA were elevated but attenuated in urban areas. No statistically significant associations were observed for preterm birth in either rural or urban areas. Residual confounding may explain observed differences in effect estimates between rural versus urban areas. For example, air and water pollution concentrations could differ regionally based on dispersion and hydrological transport patterns. Additionally, individual factors that could not be measured such as maternal occupation, housing quality, indoor air quality, dependence on groundwater sources for drinking water, and underlying population sensitivity to upstream OGD-related pollutants may have contributed to differences in effect estimates between rural and urban settings. The authors controlled for community-level factors (geographic setting, concentrations of modeled NO_2 to account for emission sources other than oil and gas, and income) and individual-level factors for infants (sex, month/year of birth) and mothers (age, race/ethnicity, educational attainment, Kotelchuk index of prenatal care, and child parity). In sensitivity analyses, accounting for pre-pregnancy body mass index, smoking during pregnancy, and exposure to Toxic Release Inventory facilities did not substantially change effect estimates (<10%) compared to the main model. This suggests that the associations were not spuriously associated with exposure to oil and gas wells due to uncontrolled confounders.

Tran et al. 2021

Tran et al. (2021) conducted a retrospective cohort study of 979,961 births to pregnant people in eight California counties (Colusa, Fresno, Glenn, Kern, Los Angeles, Orange, Santa Barbara, and Ventura) with hydraulic fracturing (HF) between 2006 and 2015. Exposed individuals had at least one oil and gas well hydraulically fractured within 1 km (3,281 ft) of their residence during pregnancy. The reference (unexposed) population had no wells within 1 km (3,281 ft), but at least one oil/gas well within 10 km (6.2 miles). Analyses assessed associations between HF and low birth weight, preterm birth, small for gestational age birth and term birth weight. Fewer than 1% of mothers (n=1,192) were exposed to HF during pregnancy. Among rural mothers, HF exposure was associated with significantly increased odds of low birth weight and small for gestational age birth, and significantly lower term birth weight. Among urban mothers, HF exposure was positively associated with small for gestational age birth, inversely associated with preterm birth, and not significantly associated with the other birth outcomes. As discussed above, residual confounding may explain observed differences in effect estimates between rural versus urban areas. The authors controlled for community-level factors (geographic setting, concentrations of modeled nitrogen dioxide [NO_2] to account for emission sources other than oil and gas, and income) and individual-level factors for infants (sex, month/year of birth) and mothers (age, race/ethnicity, educational attainment, Kotelchuk index of prenatal care, and child parity).

Peer-reviewed study findings by perinatal health endpoint

Below we discuss findings by specific perinatal health endpoint, including preterm birth, low birth weight, term birth weight, small for gestational age, congenital anomalies, congenital heart defects, neural tube defects and oral clefts, infant health index, low Apgar score, fetal death, and maternal outcomes including high-risk pregnancy and gestational hypertension and eclampsia.

Preterm birth

Preterm birth, defined as less than 37 weeks of gestation, is one of the most commonly evaluated adverse birth outcomes in the peer-reviewed literature. Thirteen studies examine the association between upstream OGD and preterm birth; three studies were conducted in California (described above) (Gonzalez et al., 2020; Tran et al., 2020, 2021), and ten additional studies were conducted in other oil and gas regions including Colorado (McKenzie et al., 2014; Erickson et al., 2022); Pennsylvania (Casey et al., 2016; Hill, 2018; Stacy et al., 2015); Texas (Cushing et al., 2020; Walker Whitworth et al., 2018; Whitworth et al., 2017); and Canada (Cairncross et al., 2022; Caron-Beaudoin et al., 2020). These studies evaluated potential exposures and outcomes over two decades, from 1996 to 2018.

Eight of the 13 studies examining preterm birth report a positive association between upstream OGD and preterm birth. In addition to one study in California (Gonzalez et al., 2020), six of these studies across two oil and gas regions (Pennsylvania and Texas) found statistically significant increases in preterm birth among infants born to mothers in the highest exposed groups living in proximity to upstream OGD (**Figure 3.4**) (Cairncross et al., 2022; Casey et al., 2016; Cushing et al., 2020; Hill, 2018; Walker Whitworth et al., 2018; Whitworth et al., 2017). One study reported increases in preterm birth that were not statistically significant (Caron-Beaudoin et al., 2022). The studies evaluated proximity to upstream OGD at distances within 2,640 ft (0.8 km) from at least one oil and gas site to out beyond 10 miles (16.1 km). For example, two studies conducted in Texas found preterm birth rates significantly increased with exposure to upstream OGD within 2,640 ft (0.8 km) during the drilling phase, production phase, as well as all phases of OGD (**Figure 3.4**) (Walker Whitworth et al., 2018; Whitworth et al., 2017). These findings were observed in the Barnett Shale region of Texas, with effects remaining significant up to 10 miles (16.1 km) for those in the highest exposure tertile (Walker Whitworth et al., 2018; Whitworth et al., 2017). Similarly, a study conducted in Alberta, Canada, found that, mothers living within 10 km (6.2 miles) of more than 100 hydraulically fractured wells during one year prior to conception through birth of their child had a significantly increased risk of preterm birth (Cairncross et al., 2022).

Four studies report null associations between preterm birth and upstream OGD: two in California (Tran et al., 2020, 2021), one in Pennsylvania (Stacy et al., 2015), and one in Colorado (Erickson et al., 2022). Finally, one study, which was the first to examine upstream OGD and adverse birth outcomes, reported a statistically significant inverse association between upstream OGD and preterm birth in Colorado (McKenzie et al., 2014). The inverse association between upstream OGD and preterm birth observed in some studies may be due to residual confounding from area-level socioeconomic characteristics or environmental factors. Additionally, a live birth bias may occur if exposed mothers (compared with unexposed mothers) were more likely to experience fetal loss (Bruckner and Catalano, 2018; Goin et al., 2021)

McKenzie et al. (2014) reported findings that appear to contradict other, more recent studies. This may be due to different methodologies to estimate exposure to OGD, as well as the availability of additional information to control for factors such as prenatal care and healthcare usage during pregnancy. Time periods examined across these studies also vary, potentially contributing to the differences in findings between studies. Of note, the study period relied upon by McKenzie et al. (2014) included live births occurring between 1996–2009, whereas Stacy et al. (2015) and Tran et al. (2020) evaluated exposures using more recent health records, with study periods spanning from 2007–2010 and 2006–2015, respectively.

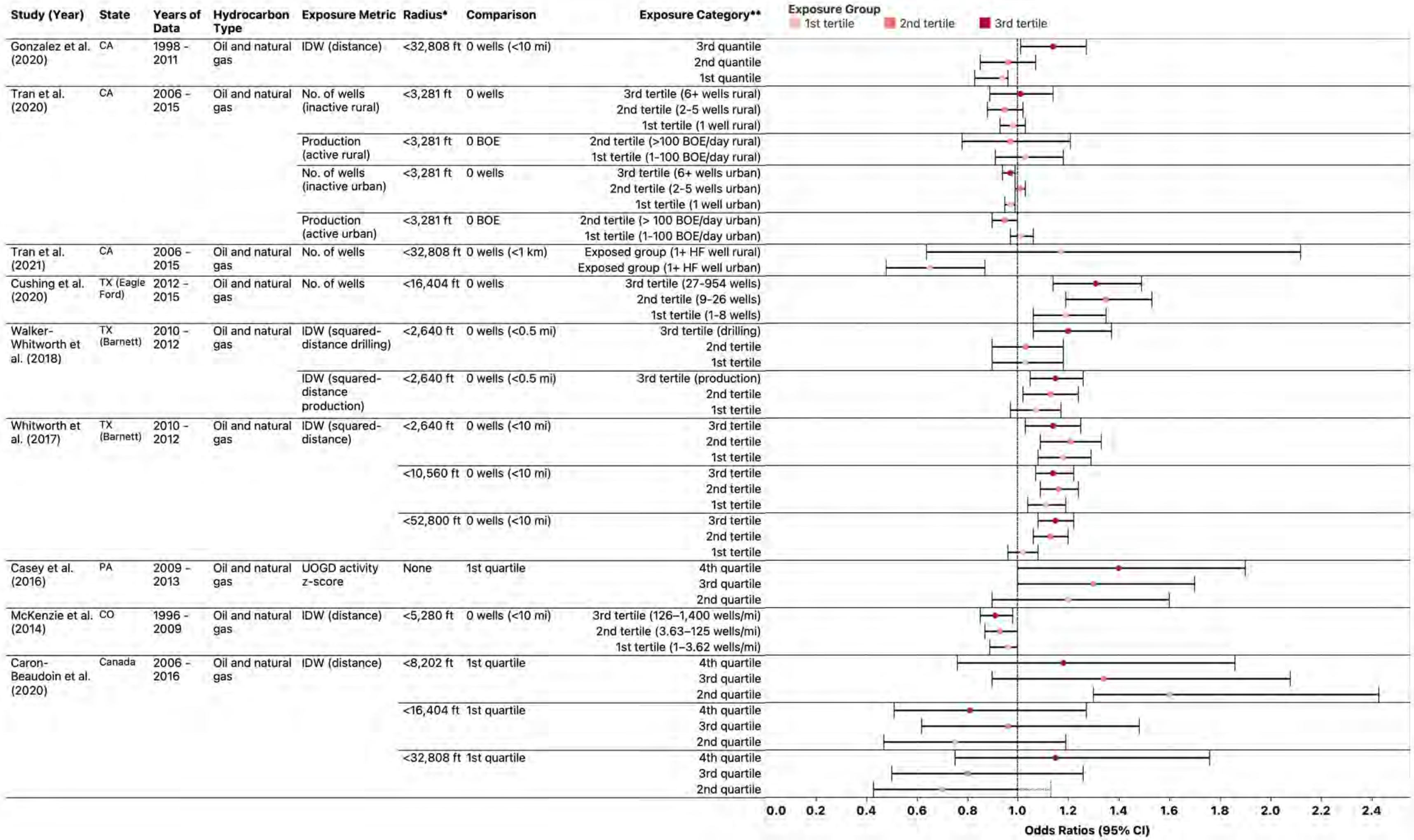

Figure 3.4. Summary of studies assessing the association between upstream oil and gas development and preterm birth (<37 weeks gestation).

* Radius represents the distance used to define exposed individuals.

** The exposure category represents the name of the category as defined by the original study. To provide visual comparability, we standardized each exposure group into tertiles: the 1st tertile indicates low activity, the 2nd tertile indicates medium activity, and the 3rd tertile indicates high activity. Quantiles/quartiles were fitted in the same fashion.

Note: Results from Cairncross et al. (2022) did not include estimated odds ratios (or risk ratios) for preterm birth but rather specific subtypes: spontaneous vs. indicated. It was therefore excluded from the figure. Erickson et al. (2022) did not include estimated odds ratios (or risk ratios) but rather reported prematurity hazards ratios. Stacy et al. (2015) displays odds ratios for all tertiles in figure form only. Additionally, Hill (2018) assessed prematurity but did not provide comparable effect estimates. Therefore, these four studies were excluded from the figure.

Abbreviations: BOE = barrels of oil equivalent; HF = hydraulically fractured; IDW = inverse distance weighted; UOGD = unconventional oil and gas development.

Low birth weight

In addition to two studies in California (Tran et al., 2020, 2021), four additional studies conducted in Colorado (McKenzie et al., 2014), Pennsylvania (Currie et al., 2017; Hill, 2018), and Oklahoma (Apergis et al., 2019) evaluated exposure to upstream OGD and low birth weight (birth weight of <2500 g, <5.51 lbs). These studies evaluated upstream OGD and low birth weight from 1996 to 2017. Five of six studies found a statistically significantly higher risk of low birth weight in the highest activity category for oil and gas communities compared to those individuals located farther away (Apergis et al., 2019; Currie et al., 2017; Hill, 2018; Tran et al., 2020, 2021). One study conducted in Colorado, McKenzie et al. (2014), found a statistically significant lower risk of low birth weight associated with exposure to upstream oil and gas development, an inverse relationship similar to that observed for preterm birth in the same study (discussed above).

Term birth weight

Thirteen peer-reviewed studies examine exposure to upstream OGD development and differences in birth weight, including two studies in California (Tran et al., 2020, 2021), two studies in Colorado (McKenzie et al., 2014; Erickson et al., 2022), one in Oklahoma (Apergis et al., 2019), four studies in Pennsylvania (Casey et al., 2016; Currie et al., 2017; Hill, 2018; Stacy et al., 2015), three studies in Texas (Cushing et al., 2020; Whitworth et al., 2017; Willis et al., 2021), and one study in British Columbia (Caron-Beaudoin et al., 2020). These studies evaluated upstream OGD and term birth weight across these different geographic regions between 1996 and 2019.

Nine of 13 studies report a statistically significant inverse association between exposure to upstream OGD and term birth weight (>37 week gestation) in California, Oklahoma, Pennsylvania, Texas, and British Columbia (Apergis et al., 2019; Caron-Beaudoin et al., 2020; Casey et al., 2016; Currie et al., 2017; Cushing et al., 2020; Stacy et al., 2015; Tran et al., 2020; 2021; Willis et al., 2021). Studies that examine mean birth weight *at term* under varying distances and levels of activity are summarized in **Figure 3.5**. Whitworth et al. (2017) found no association for term birth weight, and — similar to findings for low birth weight and preterm birth — McKenzie et al. (2014) observed a statistically significant positive association between term birth weight and exposure to upstream OGD. These results are consistent with Erickson et al. (2022), an ecological study that reported a strong positive association between term birth weight and well density and birth weight and production, but a negative association to their interaction effect.

Small for gestational age birth

Compared to low birth weight, fewer studies have examined small for gestational age birth — or birthweight less than the country sex-specific 10th percentile of weight for each week of gestation. Of these 10 studies, four (40%) report a positive association, including two studies in California (Tran et al., 2020, 2021), one in Alberta, Canada (Cairncross et al., 2022) and two studies in Pennsylvania (Hill, 2018; Stacy et al., 2015); five studies report null associations for small for gestational age (Caron-Beaudoin et al., 2020; Casey et al., 2016; Cushing et al., 2020; Whitworth et al., 2017; Willis et al., 2021).

Study (Year)	State	Years of Data	Hydrocarbon Type	Exposure Metric	Comparison	Radius*	Exposure Category**
Willis et al. (2021)	TX	1996 - 2009	Oil and natural gas	Residential proximity to drilling	Far from wells (3-10km)	<3,281 ft	3rd tertile (<3,281 ft)
						3,281 ft-6,562 ft	2nd tertile (3,281 ft-6,562 ft)
						6,562 ft -9,843 ft	1st tertile (6,562 ft -9,843 ft)
Cushing et al. (2020)	TX (Eagle Ford)	2012 - 2015	Oil and natural gas	No. of wells	0 wells	<16,404 ft	3rd tertile (27-954 wells)
							2nd tertile (9-26 wells)
							1st tertile (1-8 wells)
Whitworth et al. (2017)	TX (Barnett)	2010 - 2012	Natural gas	IDW (squared-distance)	0 wells (<10 mi)	<2,640 ft	3rd tertile
							2nd tertile
							1st tertile
						<10,560 ft	3rd tertile
							2nd tertile
							1st tertile
						<52,800 ft	3rd tertile
							2nd tertile
							1st tertile
Tran et al. (2021)	CA	2006 - 2015	Oil and natural gas	No. of wells	0 wells (<1 km)	<32,808 ft	Exposed group (1+ HF well urban)
							Exposed group (1+ HF well rural)
Tran et al. (2020)	CA	2006 - 2015	Oil and natural gas	Production (Active Rural)	0 BOE	<3,281 ft	2nd tertile (>100 BOE/day rural)
							1st tertile (1-100 BOE/day rural)
				No. of wells (Rural)	0 wells	<3,281 ft	3rd tertile (6+ wells rural)
							2nd tertile (2-5 wells rural)
							1st tertile (1 well rural)
				Production (Active Urban)	0 BOE	<3,281 ft	2nd tertile (> 100 BOE/day urban)
							1st tertile (1-100 BOE/day urban)
				No. of wells (Urban)	0 wells	<3,281 ft	3rd tertile (6+ wells urban)
							2nd tertile (2-5 wells urban)
							1st tertile (1 well urban)
Hill (2018)	PA	2003 - 2010	Natural gas	Well density	Pre-drilling	<8,202 ft	Post-drilling
				Well location	Pre-drilling	<8,202 ft	Post-drilling
Casey et al. (2016)	PA	2009 - 2013	Natural gas	UOGD activity z-score	1st quartile	None	4th quartile
							3rd quartile
							2nd quartile
McKenzie et al. (2014)	CO	1996 - 2009	Natural gas	IDW (distance)	0 wells (<10 mi)	<5,280 ft	3rd tertile (126–1,400 wells/mi)
							2nd tertile (3.63–125 wells/mi)
							1st tertile (1–3.62 wells/mi)
Caron-Beaudoin et al. (2020)	Canada	2006 - 2016	Oil and natural gas	IDW (distance)	1st quartile	<8,202 ft	4th quartile
							3rd quartile
							2nd quartile
						<16,404 ft	4th quartile
							3rd quartile
							2nd quartile
						<32,808 ft	4th quartile
							3rd quartile
							2nd quartile

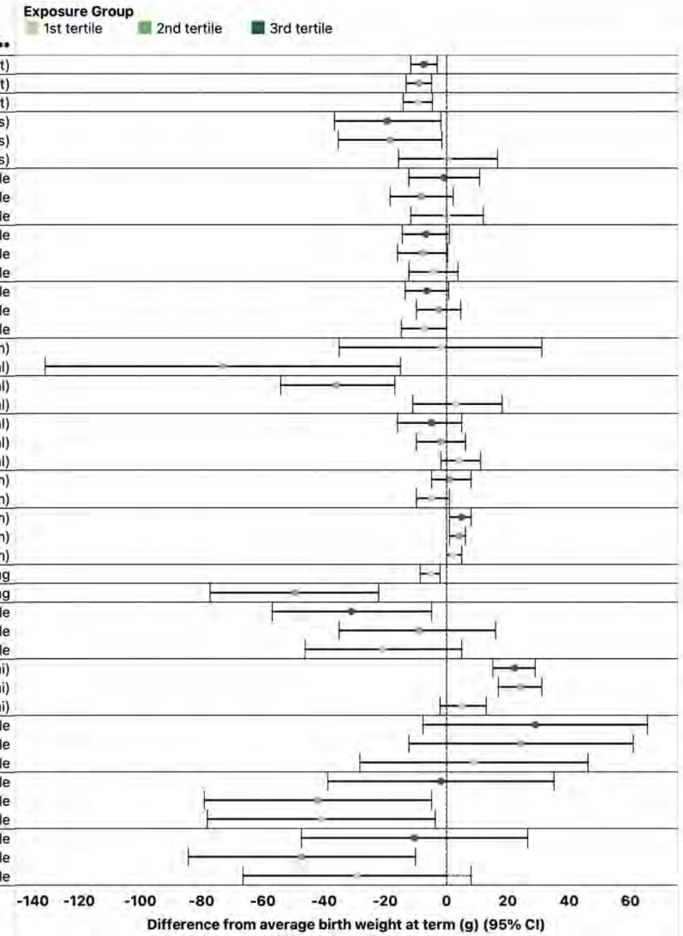

Figure 3.5. Summary of associations in the peer-reviewed literature between upstream oil and gas development and differences in term birth weight (>37 weeks gestation).
* Radius represents the distance used to define exposed individuals.
** The exposure category represents the name of the category as defined by the original study. To provide visual comparability, we standardized each exposure group into tertiles: the 1st tertile indicates low activity, the 2nd tertile indicates medium activity, and the 3rd tertile indicates high activity. Quantiles/quartiles were fitted in the same fashion.
Note: The figure only includes studies with estimated odds ratios for birth weight in grams at term, defined as any birth that occurs >37 weeks gestation. Studies that did not explicitly mention evaluation of differences in birthweight *at term* were omitted from this figure (Apergis et al., 2019; Currie et al., 2017; Erickson et al., 2022; Stacy et al., 2015).
Abbreviations: BOE = barrels of oil equivalent; IDW = inverse distance weighted; UOGD = unconventional oil and gas development.

Congenital anomalies

Nine studies assess the association between upstream OGD and congenital anomalies from 1996 to 2018 (Gaughan et al., 2023; Han et al., 2023; Hill, 2018; Janitz et al., 2019; Ma, 2016; McKenzie et al., 2014, 2019a; Tang et al., 2021; Willis et al., 2023, Cairncross et al. 2022). Because congenital anomalies include etiologically different types of birth defects, we summarize and present study results by total, non-specific birth defects, as well as the three most specific types of birth defects evaluated: congenital heart, neural tube, and oral cleft defects.

Total, non-specific congenital anomalies

Six studies considered total, non-specific congenital anomalies. Three of these were ecological studies and had mixed findings. The other three were retrospective cohort studies that observed increased risk of congenital anomalies within 5 and 10 km (3.1 and 6.2 mi) of upstream OGD.

Ecological studies. Two studies, Hill (2018) and Ma (2016) considered all congenital anomalies among infants born to mothers in Pennsylvania. Post-drilling, Hill (2018) found a non-statistically significant decrease in congenital anomalies among infants born to mothers living within 2.5 km (8,202 ft) of an active oil and gas well. Ma (2016) found that the odds of congenital anomalies were higher among infants born in ZIP codes with unconventional natural gas development as compared to infants born in ZIP codes without unconventional natural gas development. However, prevalence of birth defects decreased in ZIP codes with and without unconventional natural gas development after drilling occurred.

Han et al. (2023) conducted an ecological study of four Texas counties with active OGD, and with the highest gas production in the Barnett Shale area from 1999–2014 (Tarrant, Johnson, Wise, and Denton counties [listed from highest to lowest production 1999–2014]). Han et al. (2023) also observed that the risk of total birth defects increased with the annual county -level annual natural gas production as a proxy measure of exposure to OGD and estimated standardized morbidity ratios (SMR), accounting for maternal age and race/ethnicity as well as other demographic factors by county for various study periods (1999–2002, 2003–2006, 2007–2010, 2011–2014). For total birth defects, Tarrant County had an elevated SMR in each time period, Johnson County in three, and Wise County in one. Denton County did not differ from the expected number of cases.

While some of these studies indicates a decrease in rates of congenital anomalies over time, each study examines exposures and outcomes at the group-level (e.g., the ZIP code or county level), as opposed to examining proximity to well sites or well density near maternal residence. Therefore, these studies do not examine exposures to OGD as granularly as the retrospective cohort and case-control studies that evaluate exposure at the individual level. Additionally, the grouping of all types of congenital defects together pushes the result towards the null, which makes it more difficult to detect associations.

Retrospective cohort studies: Cairncross et al. (2022), Gaughan et al. (2023), and Willis et al. (2023) undertook retrospective cohort studies and considered all congenital anomalies among infants born to mothers in Alberta, Ohio, and Texas, respectively, using data from birth defect registries and birth registries. Cairncross et al. (2022) compared presence to absence of an oil and gas well that underwent hydraulic fracturing one year prior to the conception through birth within 10 km (6.2 mi) of the birth residence. Results showed statistically significant increased odds of major congenital anomalies for children with a birth residence within 10 km (6.2 mi) of an oil and gas well that was hydraulically fractured. Gaughan et al. (2023) compared presence to absence of an unconventional oil and gas well within a 10 km (6.2 mi) buffer of the birth residence, as well as presence to absence unconventional oil and gas well hydrologically upgradient of the birth residence within the 10 km (6.2 mi) buffer of the birth residence. Results showed increased odds of any structural birth defect for children with presence of an unconventional oil and gas well in the 10 km (6.2 mi) buffer, and less precise increased odds for children with presence of an upgradient unconventional oil and gas well in the 10 km (6.2 mi) buffer. Willis et al. (2023) examined upstream OGD-related exposures using tertiles of inverse distance-squared weighting within 5 km (3.1 mi) for drilling site count, gas production, oil production, and produced water, compared to infants born to mothers living within 5 km (3.1 mi) of future drilling sites that were not yet operating during the pregnancy period (temporal comparison group). Results showed increased odds of any congenital anomaly in the highest tertile exposure group for site well count, oil production, gas production, and produced water, although associations did not follow a consistent exposure-response pattern across tertiles. Using a spatial comparison group of mothers living 5–10 km (3.1–6.1 mi) away from an upstream OGD site revealed attenuated, but still increased, odds of any congenital anomaly. While these three studies improve on the ecological design by evaluating exposure and congenital anomalies at the individual level, the grouping of all types of congenital defects together pushes the result towards the null, which makes it more difficult to detect associations.

A subset of analyses in the Gaughan, Willis, and Han studies, in addition to four other studies examined specific subsets of congenital malformations. The most commonly evaluated malformations included congenital heart defects, neural tube defects, and oral clefts.

Congenital heart defects

All seven studies that evaluated associations between upstream OGD and congenital heart defects report increased risk of congenital heart defects increasing levels of and/or proximity to OGD within 1–16.1 km (0.6–10 mi) of the birth residence. Four retrospective cohort and two case-control studies observed increased odds of congenital heart defects with increased upstream OGD.

The Han et al. (2023) ecological study described previously observed increased risks of atrial septal defects, ventricular septal defects, and patent ductus arteriosus in three, one, and two out of the four selected Texas counties. They also observed that risks of atrial septal defects and patent ductus arteriosus increased with annual natural gas production volumes. No significant associations of increased natural gas production were found with ventricular septal defects.

In the Gaughan et al. (2023) Ohio study described previously, non-statistically significant increased rates of congenital heart defects as a whole increased with presence of an unconventional oil and gas well within 10 km of the birth residence. The Willis et al. (2023) Texas study described previously found consistently increased odds of cardiac and circulatory anomalies, across tertiles of all upstream OGD exposure metrics using a temporal comparison, with results attenuated using a spatial comparison group. In another Texas study, Tang et al. (2021) employed a case-control design to examine congenital heart defects among infants born to mothers living within 1 km (3,281 ft), 3 km (1.8 mi), and 7.5 km (4.7 mi) of an active Texas oil and gas well during the year of birth. The authors found significantly increased odds of aortic valve stenosis, hypoplastic left heart syndrome, and pulmonary valve atresia or stenosis among those living within 1 km (3,281 ft), 3 km (1.8 mi), and 7.5 km (4.7 mi) of an active oil and gas well and exposed to the highest density of natural gas activity.

Results in Colorado and Oklahoma are consistent with the Texas and Ohio studies. In Colorado, McKenzie et al. (2014) employed a retrospective cohort design to compare tertiles of inverse distance weighted sums of oil and gas wells within 16.1 km (10 mi) of birth residence to absence of any OGD within 16.1 km (10 mi). They reported a statistically significant, monotonically increasing risk of congenital heart defects with increasing inverse distance weighted sum of oil and gas wells within 16.1 km (10 mi) of the birth residence In a follow up Colorado study, McKenzie et al. (2019a) employed a nested case control design to examine the relationship between more specific congenital heart defects and the inverse distance weighted oil and gas well count, adjusted for intensity of oil and gas activity. They also consider other major air population sources in the analysis. Similar to their first study, they observed a statistically significant monotonic increase in odds of total congenital heart defects, with increasing intensity adjusted inverse distanced weighted counts of oil and wells, within 16.1 km (10 mi) of the birth residence. They also observed a positive, though not statistically significant, association between upstream OGD and specific congenital heart defects, including aortic artery and valve defects, pulmonary artery and valve defects, conotruncal defects, and tricuspid valve defects. In Oklahoma, Janitz et al. (2019) conducted a retrospective cohort study to compare inverse distance weighted counts of actively producing natural gas wells within two miles (3.2 km) of the birth residence. While they did not find an association between upstream OGD and critical congenital heart defects as a whole; when broken out by specific defect, the authors found non-statistically significant but increased rates of common truncus, transposition of the great arteries, pulmonary valve atresia and stenosis, tricuspid valve atresia and stenosis, interrupted aortic arch, and total anomalous pulmonary venous connection among children living in areas of upstream OGD.

Studies that evaluated congenital heart defects are summarized in **Figure 3.6**

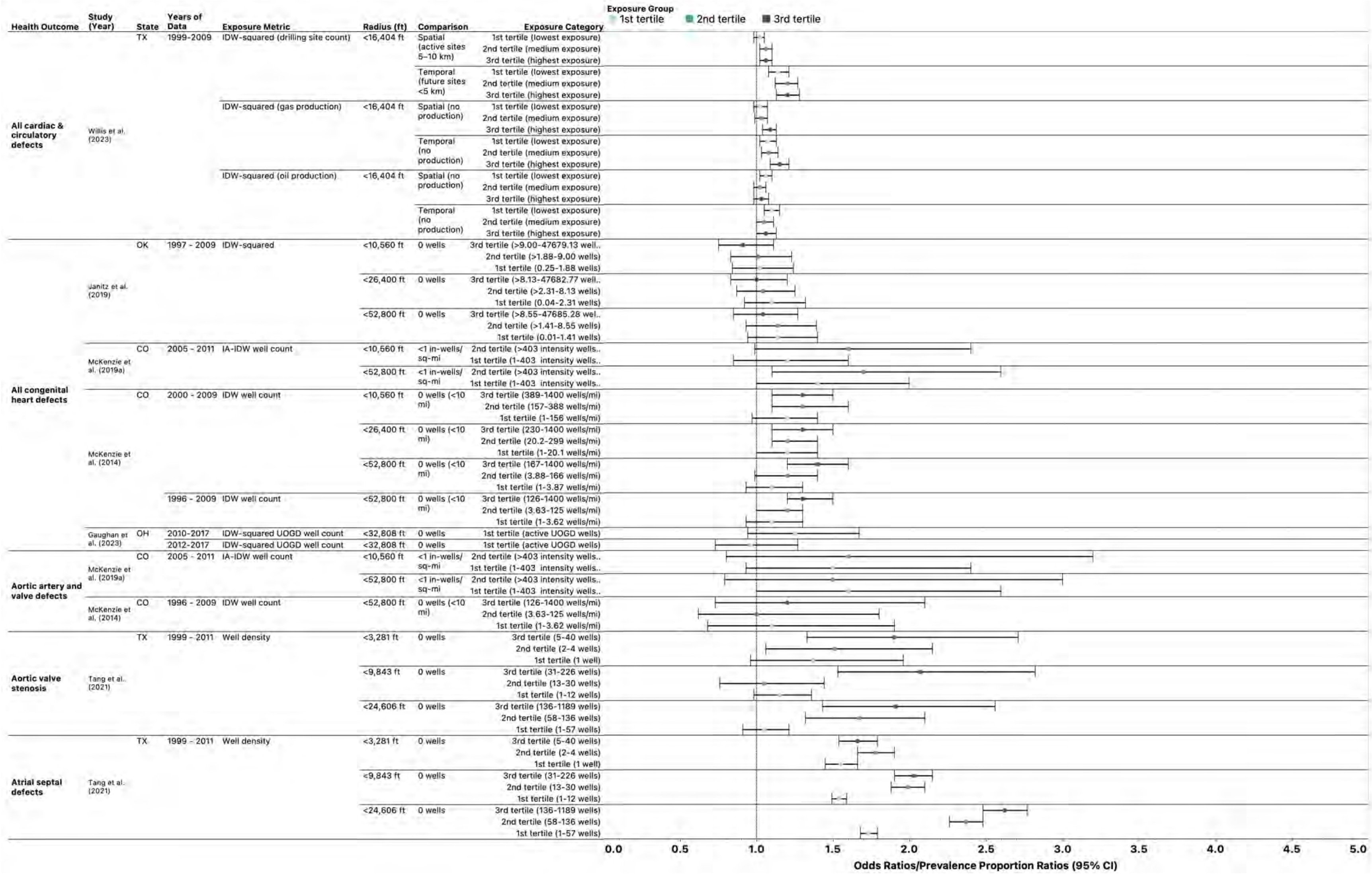

Figure 3.6. Summary of associations in the peer-reviewed literature between upstream oil and gas development and congenital heart defects. See notes on last series of forest plots that comprise Figure 3.6.

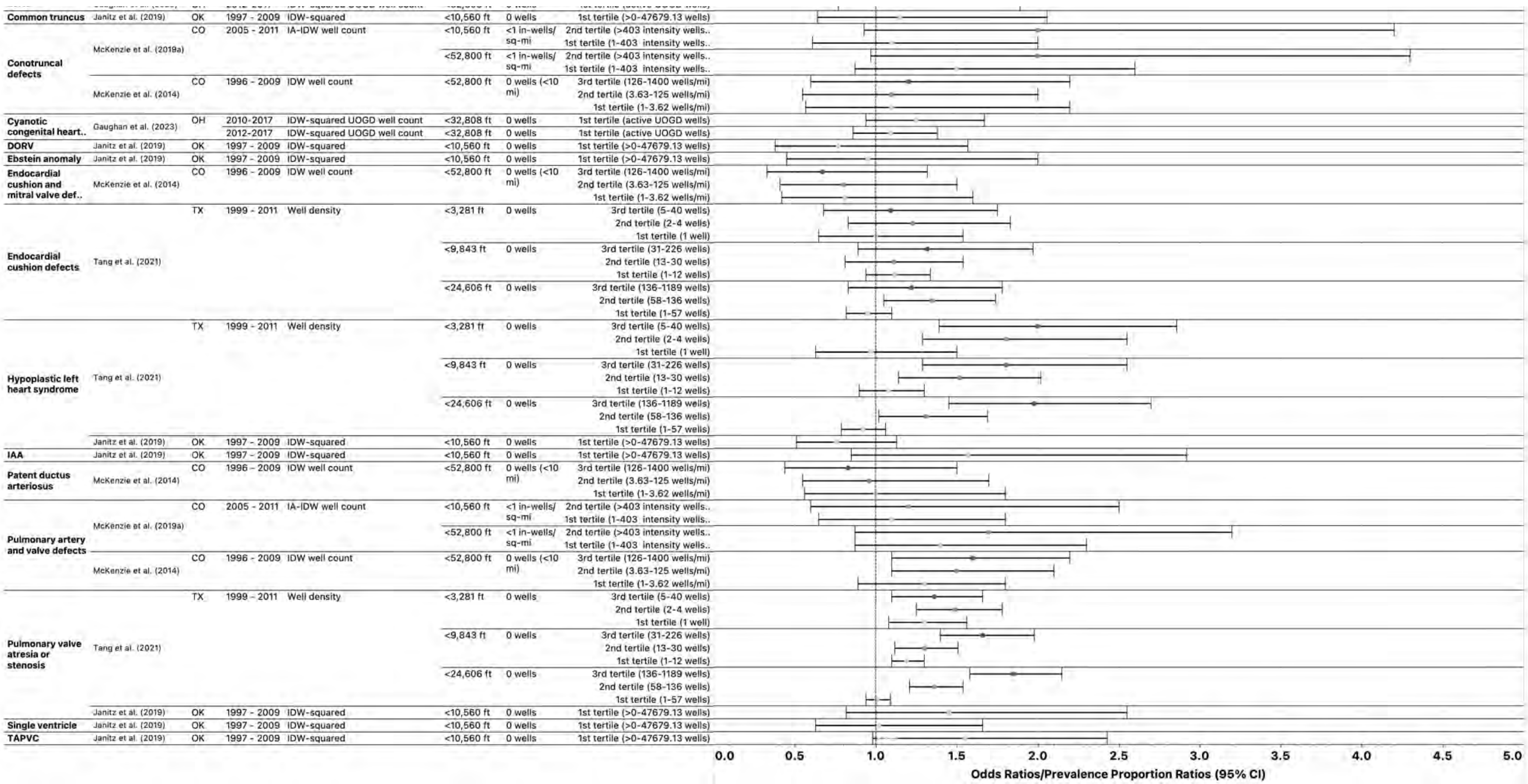

Figure 3.6. ***continued*** Summary of associations in the peer-reviewed literature between upstream oil and gas development and congenital heart defects. See notes on last series of forest plots that comprise Figure 3.6.

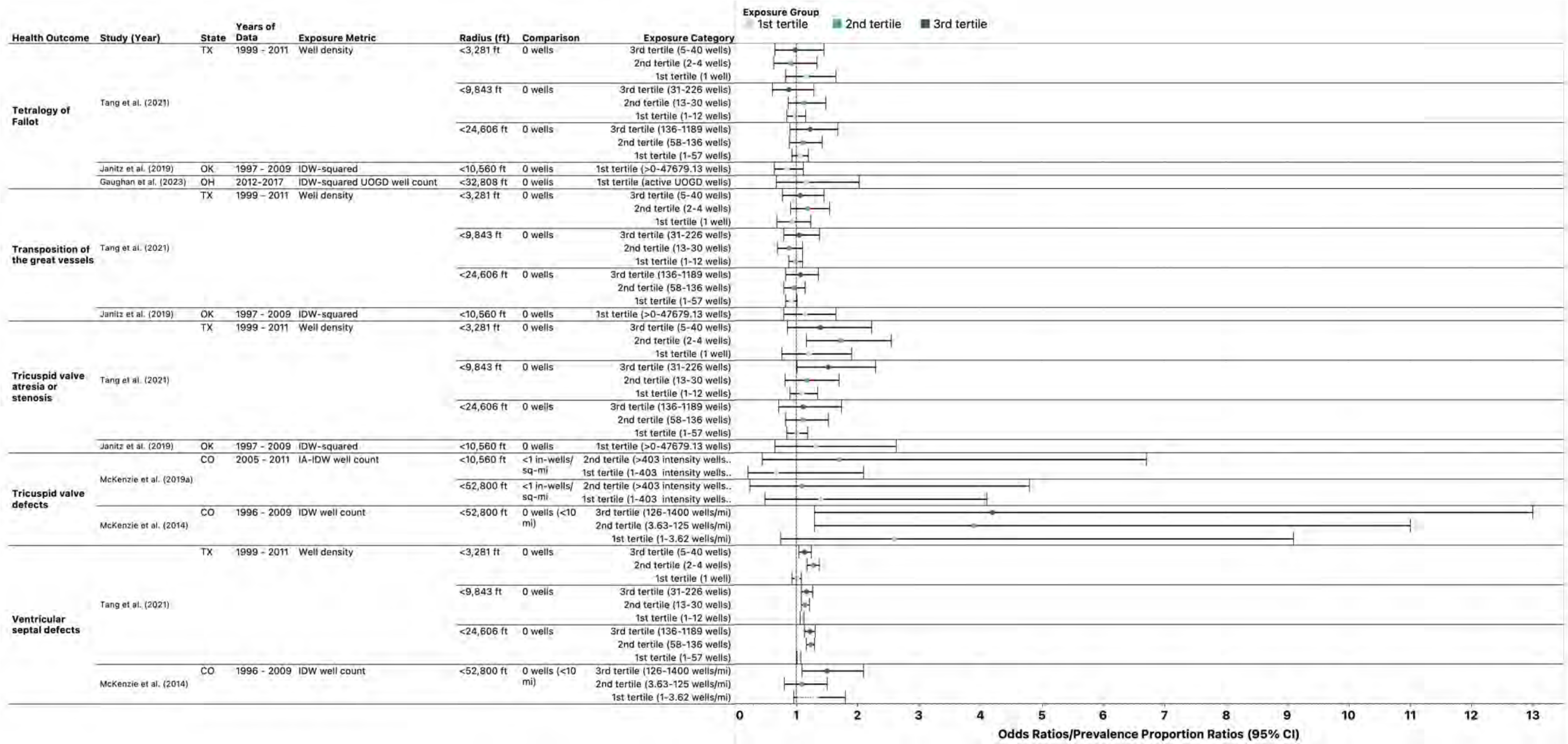

Figure 3.6. *continued* Summary of associations in the peer-reviewed literature between upstream oil and gas development and congenital heart defects.

* Radius represents the distance used to define exposed individuals.

** The exposure category represents the name of the category as defined by the original study. To provide visual comparability, we standardized each exposure group to tertiles, with the 1st tertile representing low activity, the 2nd tertile representing medium activity, and the 3rd tertile representing high activity. Quantiles/quartiles were fitted in the same fashion.

Note: Results from Han et al. (2023) did not include estimated odds ratios (or risk ratios) and was therefore excluded from the figure.

Abbreviations: BOE = barrels of oil equivalent; DORV = Double outlet right ventricle; IA-IDW = intensity-adjusted inverse distance weighted; IDW = inverse distance weighted; IAA = Interrupted Aortic arch TAPVC = Total anomalous pulmonary venous connection; UNGD = unconventional natural gas development.

Neural tube defects

Five out of six studies that evaluated neural tube defects and upstream OGD found that the risk of neural tube defects increased with increasing level activity and/or proximity to upstream OGD within 1–16.1 km (0.6–10 mi) of the birth residence.

The Han et al (2023) ecological study described previously observed increased risks of severe microcephaly and hydrocephaly without spina bifida in two out of four selected Texas counties. They did not observe that risks of microcephaly or hydrocephaly without spina bifida increased with annual natural gas production volumes.

Four retrospective cohort studies and one case-control study examined neural tube defects (Janitz et al., 2019; McKenzie et al., 2014; Tang et al., 2021; Willis et al., 2023). In Ohio, the previously described Gaughan et al. (2023) study found elevated odds of neural tube defects among women living within 10 km of upstream OGD sties. The previously described Tang et al. (2021) Texas study found significantly increased odds of spina bifida and anencephaly, two subtypes of neural tube defects. The previously described Janitz et al. (2019) study found that among children living in Oklahoma within two miles (3.2 km) of natural gas activity, prevalence of neural tube defects was increased compared to children exposed to zero wells, though these findings were not statistically significant. The previously described McKenzie et al. (2014) study found significantly increased odds of neural tube defects in children exposed to the highest level of oil and gas activity compared to children exposed to no active gas wells within a 10-mile (16.1 km) radius. While the sample size was small, findings were statistically significant, indicating a potential association. However, the previously described Willis et al. (2023) study did not find significant associations of neural tube defects among Texas infants living within 5 km (3.1 mi) of OGD sites using multiple exposure metrics as well as a temporal or spatial comparison group.

Studies that evaluated neural tube defects are summarized in **Figure 3.7.**

Oral cleft defects

Five previously described studies examined associations between oral cleft defects and upstream OGD (Janitz et al., 2019; McKenzie et al., 2014; Tang et al., 2021, Gaughan et al., 2023, Willis et al., 2023). Mckenzie et al. (2014), Janitz et al. (2019), Tang et al. (2021), and Willis et al. (2023) found no association between upstream OGD and oral cleft defects. Studies that evaluated cleft defects are summarized in **Figure 3.8.**

Health Outcome	Study (Year)	State	Exposure Time Period	Primary Hydrocarbon	Exposure	Radius	Comparison	Exposure Category
All neural tube defects	Janitz et al. (2019)	OK	1997 - 2009	Gas	IDW (squared-distance)	<10,560 ft	0 wells	3rd tertile (> 9.00-47679.13 well..
								2nd tertile (>1.88-9.00 wells)
								1st tertile (0.25-1.88 wells)
						<26,400 ft	0 wells	3rd tertile (>8.13-47682.77 wells)
								2nd tertile (>2.31-8.13 wells)
								1st tertile (0.04-2.31 wells)
						<52,800 ft	0 wells	3rd tertile (>8.55-47685.28 well..
								2nd tertile (>1.41-8.55 wells)
								1st tertile (0.01-1.41 wells)
	McKenzie et al. (2014)	CO	2000 - 2009	Gas	IDW well count	<10,560 ft	0 wells (<10 mi)	3rd tertile (389-1400 wells/mi)
								2nd tertile (157-388 wells/mi)
								1st tertile (1-156 wells/mi)
						<26,400 ft	0 wells (<10 mi)	3rd tertile (230-1400 wells/mi)
								2nd tertile (20.2-299 wells/mi)
								1st tertile (1-20.1 wells/mi)
						<52,800 ft	0 wells (<10 mi)	3rd tertile (167-1400 wells/mi)
								2nd tertile (3.88-166 wells/mi)
								1st tertile (1-3.87 wells/mi)
			1996 - 2009	Gas	IDW well count	<52,800 ft	0 wells (<10 mi)	3rd tertile (126-1400 wells/mi)
								2nd tertile (3.63-125 wells/mi)
								1st tertile (1-3.62 wells/mi)
	Gaughan et al. (2023)	OH	2010-2017	Both	IDW-squared UOGD well ..	<32,808 ft	0 wells	1st tertile (active UOGD wells)
			2012-2017	Both	IDW-squared UOGD well ..	<32,808 ft	0 wells	1st tertile (active UOGD wells)
	Willis et al. (2023)	TX	1999-2009	Both	IDW-squared (drilling site count)	<16,404 ft	Spatial (active sites 5–10 km)	1st tertile (lowest exposure)
								2nd tertile (medium exposure)
								3rd tertile (highest exposure)
							Temporal (future sites <5 km)	1st tertile (lowest exposure)
								2nd tertile (medium exposure)
								3rd tertile (highest exposure)
					IDW-squared (gas production)	<16,404 ft	Spatial (no production)	1st tertile (lowest exposure)
								2nd tertile (medium exposure)
								3rd tertile (highest exposure)
							Temporal (no production)	1st tertile (lowest exposure)
								2nd tertile (medium exposure)
								3rd tertile (highest exposure)
					IDW-squared (oil production)	<16,404 ft	Spatial (no production)	1st tertile (lowest exposure)
								2nd tertile (medium exposure)
								3rd tertile (highest exposure)
							Temporal (no production)	1st tertile (lowest exposure)
								2nd tertile (medium exposure)
								3rd tertile (highest exposure)

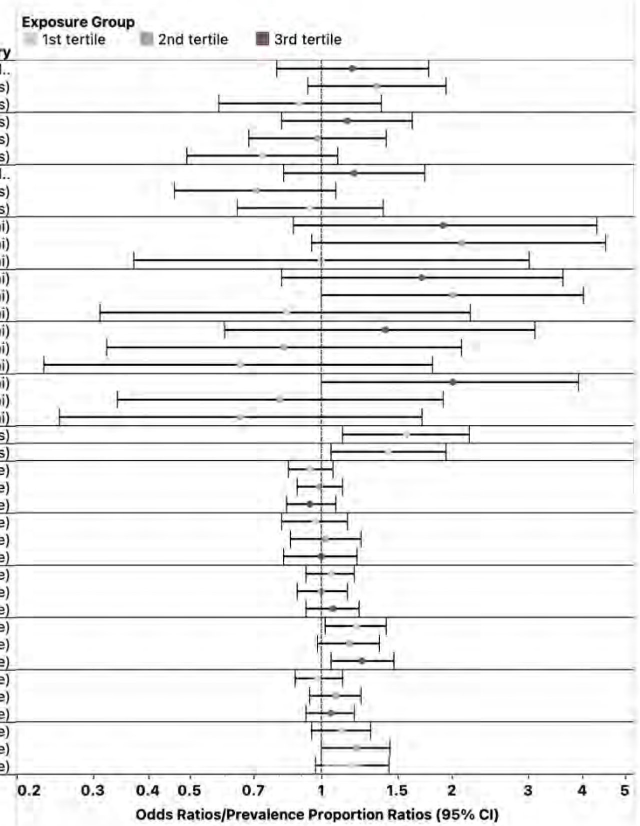

Figure 3.7. Summary of associations in the peer-reviewed literature between upstream oil and gas development and neural tube defects

* Radius represents the distance used to define exposed individuals.
** The exposure category represents the name of the category as defined by the original study. To provide visual comparability, we standardized each exposure group to tertiles, with the 1st tertile representing low activity, the 2nd tertile representing medium activity, and the 3rd tertile representing high activity. Quantiles/quartiles were fitted in the same fashion.
Abbreviations: IDW = inverse distance weighted; UNGD = unconventional natural gas development.

Health Outcome	Study (Year)	State	Exposure Time Period	Primary Hydrocarbon	Exposure	Radius	Comparison	Exposure Category
Anencephaly	Tang et al. (2021)	TX	1999 - 2011	Gas	Well density	<3,281 ft	0 wells	3rd tertile (5-40 wells)
								2nd tertile (2-4 wells)
								1st tertile (1 well)
						<9,843 ft	0 wells	3rd tertile (31-226 wells)
								2nd tertile (13-30 wells)
								1st tertile (1-12 wells)
						<24,606 ft	0 wells	3rd tertile (136-1189 wells)
								2nd tertile (58-136 wells)
								1st tertile (1-57 wells)
	Janitz et al. (2019)	OK	1997 - 2009	Gas	IDW (squared-distance)	<10,560 ft	0 wells	1st tertile (> 0-47679.13 wells)
	Gaughan et al. (2023)	OH	2010-2017	Both	IDW-squared UOGD well ..	<32,808 ft	0 wells	1st tertile (active UOGD wells)
			2012-2017	Both	IDW-squared UOGD well ..	<32,808 ft	0 wells	1st tertile (active UOGD wells)
Spina bifida	Tang et al. (2021)	TX	1999 - 2011	Gas	Well density	<3,281 ft	0 wells	3rd tertile (5-40 wells)
								2nd tertile (2-4 wells)
								1st tertile (1 well)
						<9,843 ft	0 wells	2nd tertile (13-30 wells)
								1st tertile (1-12 wells)
						<09,843 ft	0 wells	3rd tertile (31-226 wells)
						<24,606 ft	0 wells	3rd tertile (136-1189 wells)
								2nd tertile (58-136 wells)
								1st tertile (1-57 wells)
	Janitz et al. (2019)	OK	1997 - 2009	Gas	IDW (squared-distance)	<10,560 ft	0 wells	1st tertile (> 0-47679.13 wells)
	Gaughan et al. (2023)	OH	2010-2017	Both	IDW-squared UOGD well ..	<32,808 ft	0 wells	1st tertile (active UOGD wells)
			2012-2017	Both	IDW-squared UOGD well ..	<32,808 ft	0 wells	1st tertile (active UOGD wells)

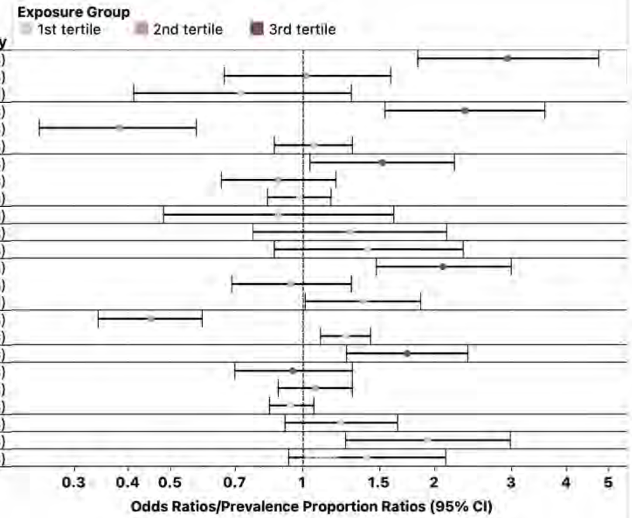

Figure 3.7. ***continued*** Summary of associations in the peer-reviewed literature between upstream oil and gas development and neural tube defects

* Radius represents the distance used to define exposed individuals.
** The exposure category represents the name of the category as defined by the original study. To provide visual comparability, we standardized each exposure group to tertiles, with the 1st tertile representing low activity, the 2nd tertile representing medium activity, and the 3rd tertile representing high activity. Quantiles/quartiles were fitted in the same fashion.
Abbreviations: IDW = inverse distance weighted; UNGD = unconventional natural gas development.

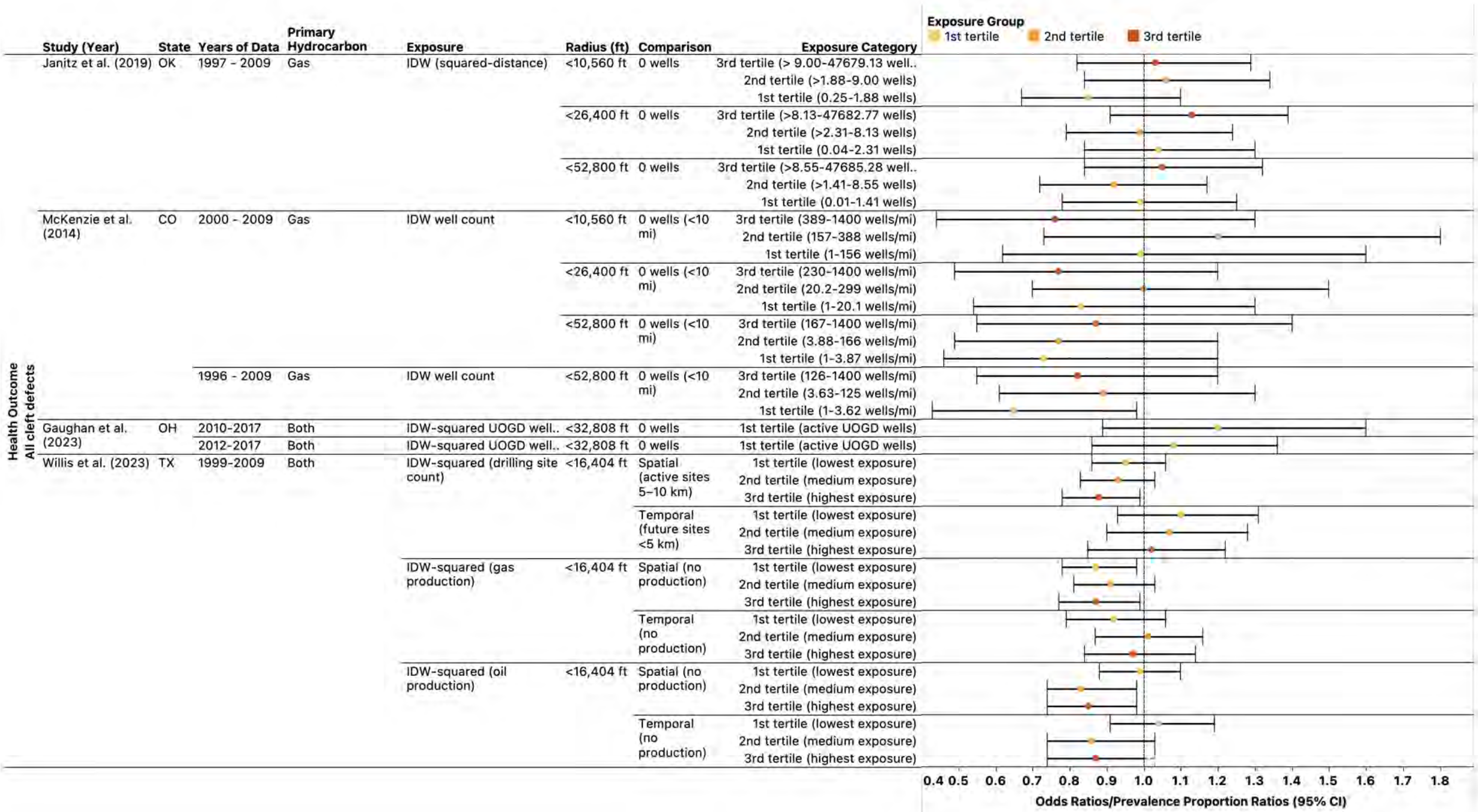

Figure 3.8. Summary of associations in the peer-reviewed literature between upstream oil and gas development and cleft defects

* Radius represents the distance used to define exposed individuals.
** The exposure category represents the name of the category as defined by the original study. To provide visual comparability, we standardized each exposure group to tertiles, with the 1st tertile representing low activity, the 2nd tertile representing medium activity, and the 3rd tertile representing high activity. Quantiles/quartiles were fitted in the same fashion.

Abbreviations: IDW = inverse distance weighted; UNGD = unconventional natural gas development.

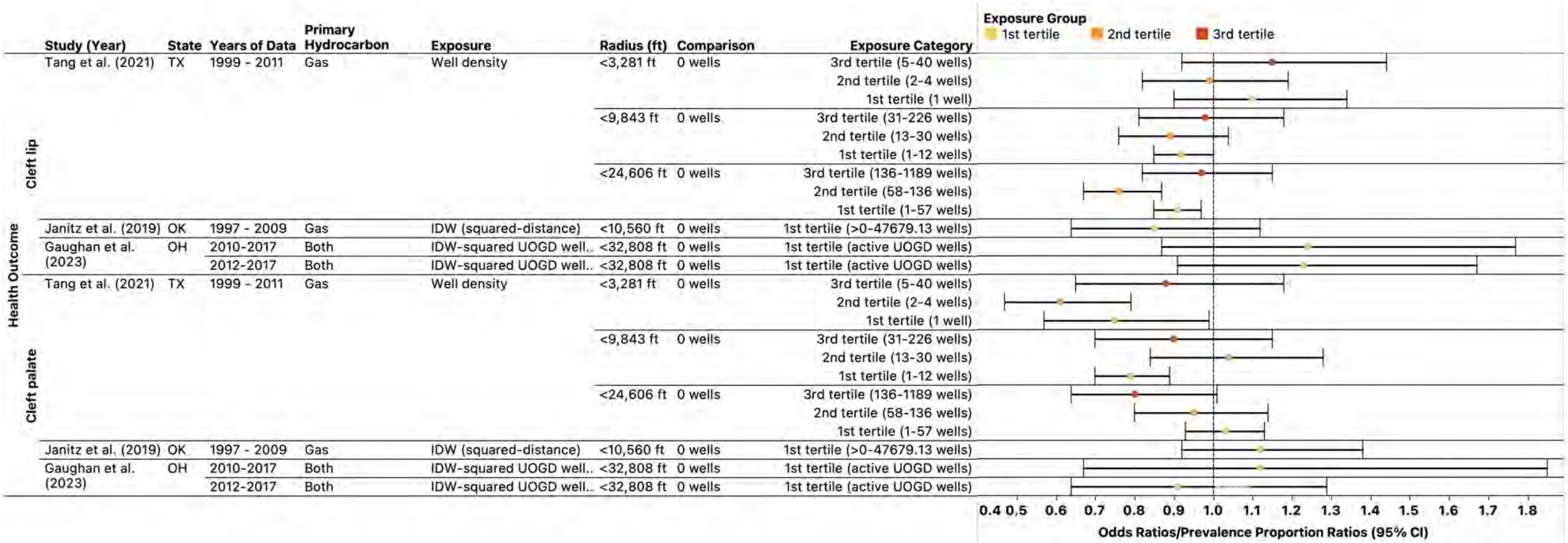

Figure 3.8. ***continued*** Summary of associations in the peer-reviewed literature between upstream oil and gas development and cleft defects

* Radius represents the distance used to define exposed individuals.
** The exposure category represents the name of the category as defined by the original study. To provide visual comparability, we standardized each exposure group to tertiles, with the 1st tertile representing low activity, the 2nd tertile representing medium activity, and the 3rd tertile representing high activity. Quantiles/quartiles were fitted in the same fashion.
Abbreviations: IDW = inverse distance weighted; UNGD = unconventional natural gas development.

Infant health index

Three studies examined the relationships between upstream OGD and the infant health index, a composite value that combines multiple factors (e.g., birth weight, prematurity, any congenital anomalies, presence of abnormal conditions) (Apergis et al., 2019; Currie et al., 2017; Hill, 2018). Infant health index values range from 0 to 1; the higher the infant health index value, the more positive the assessment of infant health at birth is (Apergis et al., 2019). Two studies were conducted in Pennsylvania (Currie et al., 2017; Hill, 2018), and one in Oklahoma (Apergis et al., 2019) for infants born between 2003 and 2017.

Apergis et al. (2019) evaluated effects of upstream OGD on infant health using data from 2006–2017 in Oklahoma. The authors found statistically significant decreases in the infant health index up to 20 km (12 mi) from hydraulically fractured oil and gas wells, with the largest decreases seen at the closest distance examined of 1km (3,281 ft). The authors also found smaller decreases in the infant health index up to 20 km (12 mi) from oil and gas wells that were not hydraulically fractured.

Results in Pennsylvania are consistent with findings in Oklahoma. Currie et al. (2017) found statistically significant decreases in the infant health index up to 3 km (1.9 mi) from hydraulically fractured oil and gas wells, with the largest decreases within 1 km (3,281 ft). Similarly, Hill (2018) found a statistically significant increase in the probability of an adverse health outcome at birth within 2.5 km (1.5 mi) of hydraulically fractured shale gas well activity post-drilling.

Low Apgar score

Two studies conducted in Pennsylvania examined low Apgar scores in relation to upstream OGD between 2003 and 2013 (Casey et al., 2016; Hill, 2018). Five-minute American Pediatric Gross Assessment Record (Apgar) scores are determined through clinician-rated review of five health dimensions at birth (heart rate, breathing effort, muscle tone, reflexes, color); each score is summed together to produce a final Apgar score ranging from 0 to 10, with lower values representing poorer infant health (Hill, 2018). Infants with low Apgar scores often require respiration support. Casey et al. (2016) defines a “low” Apgar score as any score <7, whereas Hill (2018) defines it as any score <8.

Relying on health records from 2009 to 2013, Casey et al. (2016) found no association with low Apgar score (<7) and upstream OGD. However. Hill (2018) found that the introduction of shale gas development significantly increased low Apgar score (<8) prevalence for those living within 2.5 km (1.5 mi) of hydraulically fractured shale gas wells. These differences may be due to the authors’ definition of low Apgar score; Casey et al. (2016) findings considering a low Apgar score as <7 may be more clinically relevant, as clinicians usually deem scores <7 as less healthy (ACOG, 2015).

Fetal death

Two studies assessed fetal death and upstream OGD between 2003 and 2012 (Busby & Mangano, 2017; Whitworth et al., 2017). Busby and Mangano (2017) assessed county-level infant deaths and unconventional OGD in Pennsylvania and found a significant increase in infant mortality in the 10 counties where hydraulic fracturing was present. Whitworth et al. (2017) conducted a retrospective cohort study in the Barnett Shale region of North Texas by assessing individual exposure to active oil and gas wells and fetal death. Adjusted models found increased odds of infant mortality among those living within a half-mile (2,640 ft, 0.8 km) of oil and gas activity in the highest exposure category. These effects were also observed for women living within two miles (3.2 km) of oil and gas activity in the second tertile of exposure.

High-risk pregnancy

Casey et al. (2016) evaluated adverse birth outcomes in Pennsylvania between 2009 and 2013 and also evaluated physician-reported high-risk pregnancy, a maternal health outcome, as a secondary endpoint. The authors hypothesized that natural gas development exposures could contribute to the occurrence of high-risk pregnancies through effects to the pulmonary and cardiovascular systems (Casey et al., 2016). The authors found that exposure to unconventional natural gas development was significantly associated with 30% increased odds of physician-reported high-risk pregnancy when comparing the highest level of activity to the lowest.

Gestational hypertension and eclampsia

Willis et al. (2022) examined associations between residential proximity to oil and gas extraction and hypertensive conditions during pregnancy in Texas. Using a difference-in-differences framework and adjusting for potential confounders (see **Table 3.3**), the study found that pregnant women living within 1 km (3,281 ft) of an active oil and gas well had 5% increased odds of gestational hypertension and 26% increased odds of eclampsia when compared to pregnant women living far away from extraction activities (>10 km; >6.2 mi). Significantly increased odds were not found for pregnant women living within 1–2 km (3,281–6,561 ft) or 2–3 km (6,561–9,842 ft) of an active oil and gas well (Willis et al., 2022).

Table 3.3. Summary of epidemiological studies that evaluate upstream oil and gas development and adverse perinatal health outcomes in the United States and Canada. Studies are categorized by state and then chronologically by publication year.

Author (Year)	Region	Primary hydro-carbon produced	Funder	Study design	Surrogate of exposure *(distance evaluated if specified)*	Sample size, study time frame, and outcome data source	Confounders and covariates considered	Main findings[1]
California								
Gonzalez et al. (2020)	San Joaquin Valley, CA	Oil & natural gas	NIH, March of Dimes Prematurity Research Center at Stanford University	Case-control	IDW[2] index of new and active wells within 10 km (32,808 ft) radius of maternal residence	225,374 births 27,913 cases 197,461 controls 1998–2011 California OSHPD	Mother's age, education, ethnicity/race, parity, and insurance payer, prenatal care access, neighborhood-level poverty	**Exposure during 1st or 2nd trimester:** Preterm birth (20–27 weeks) △ Preterm birth (28–31 weeks) ▲ Preterm birth (32–36 weeks) ⇔ **Exposure during 3rd trimester:** Preterm birth (32–36 weeks) ⇔
Tran et al. (2020)	San Joaquin Valley, South Central Coast & South Coast Air Basins, CA	Oil & natural gas	CARB, the 11th Hour Project, NIEHS, UC Berkeley, SAGE-IGERT Fellowship, NSF	Retrospective cohort	Exposure was defined as having one active or inactive well within 1 km (3,281 ft) of maternal residence at time of delivery; participants included residents with at least one well within 10 km (32,808 ft) Exposure to active wells was characterized by total production volume - barrels of oil and barrels of oil equivalent natural gas (BOE); exposure to inactive wells was characterized by well count	2,918,089 births 2006–2015 California Department of Public Health	Mother's age, education, race/ethnicity, prenatal care, infant sex, and birth month/year, neighborhood level concentration of wealth/poverty as measured by index of concentration at the extremes, neighborhood level traffic-related air pollution	**Active Wells (rural):** ***No BOE vs. >100 BOE/day*** Low birth weight ▲ Preterm birth ⇔ Small for gestational age ▲ Mean term birth weight ▼ **Inactive Wells (rural):** ***0 wells vs. 6+ wells*** Low birth weight ⇔ Preterm birth ⇔ Small for gestational age ⇔ Mean term birth weight ⇔ **Active Wells (urban):** ***No BOE vs. >100 BOE/day*** Low birth weight ⇔ Preterm birth ⇔ Small for gestational age ▲ Mean term birth weight ⇔ **Inactive Wells (urban):** ***0 wells vs. 6+ wells*** Low birth weight ⇔ Preterm birth ⇔ Small for gestational age ⇔ Mean term birth weight ▲

Author (Year)	Region	Primary hydro-carbon produced	Funder	Study design	Surrogate of exposure *(distance evaluated if specified)*	Sample size, study time frame, and outcome data source	Confounders and covariates considered	Main findings[1]
Tran et al. (2021)	Glenn, Colusa, Fresno, Kern, Santa Barbara, Los Angeles, Ventura, Orange counties, CA	Oil and gas	CARB, 11th Hour Project, NIEHS	Retrospective cohort	Exposed individuals had at least one well hydraulically fractured within 1 km (3,281 ft) of residence during pregnancy.	979,961 births to mothers in eight California counties with HF 2006–2015 California Department of Public Health	Infant covariates — sex, month and year of conception based on date of last menstrual period. Maternal covariates — age, race/ethnicity, educational attainment, Kotelchuck index of prenatal care, parity	**Adjusted OR, rural** Low birth weight ▲ Preterm birth △ Small for gestational age ▲ **Mean difference, rural** Term birth weight ▼ **Adjusted OR, urban** Low birth weight ▽ Preterm birth ▼ Small for gestational age △ **Mean difference, rural** Term birth weight ▽
Canada								
Caron-Beaudoin et al. (2020)	North-eastern British Columbia, Canada	Natural gas	Canadian Institutes of Health Research	Retrospective cohort	UNGD activity metric – IDW sum of wells with a spud date earlier than delivery date for 2.5, 5, 10 km (8,202, 16,404, 32,808 ft) buffers around each postal code centroid	5,018 births 2006–2015 Perinatal Data Registry and Northern Health (healthcare provider in Northeastern British Columbia)	Mother's age at delivery, prior poor pregnancy outcome, complications during current pregnancy, parity, stillbirth, singleton, multiple birth count for current pregnancy, infant's birth date, infant's biological sex assigned at birth, prior and current history of depression and mental health concerns, use of alcohol and drugs or tobacco during current pregnancy, exposure to second-hand smoke during pregnancy	**Postal code well density/proximity 4th quartile to reference (2.5 km, 8,202 ft)** Preterm birth △ (2nd quartile ▲) Birth weight ▽ Head circumference △ Small for gestational age ▽ **Postal code well density/proximity (5 km, 16,404 ft)** Preterm birth ▽ Birth weight ▽ (2nd and 3rd quartile▼) Head circumference △ Small for gestational age ▽ **Postal code well density/proximity (10 km, 32,808 ft)** Preterm birth △ Birth weight ▽ (3rd quartile ▼) Head circumference △ Small for gestational age ▽

Author (Year)	Region	Primary hydro-carbon produced	Funder	Study design	Surrogate of exposure *(distance evaluated if specified)*	Sample size, study time frame, and outcome data source	Confounders and covariates considered	Main findings[1]
Cairncross et al. (2022)	Alberta, Canada	Unconventional oil & gas	New Frontiers in Research Fund	Retrospective cohort	Residents living within 10 km (32,808 ft) of 100+ hydraulically fractured wells during first year of pregnancy or preconception	26,193 people 34,873 pregnancies 2013–2018 Alberta Health & Alberta Health Services	Age at delivery, multiple births (i.e., twins, triplets), infant sex, obstetric comorbidities, area-level socioeconomic status	**100+ wells vs. 1-24 wells within 10 km (32,808 ft):** Spontaneous preterm birth ▲ Indicated preterm birth △ Small for gestational age ▲ Severe neonatal mortality/morbidity △
Colorado								
McKenzie et al. (2014)	Rural areas in CO; towns <50,000 residents	Natural gas	Department of Environmental and Occupational Health, Colorado School of Public Health	Retrospective cohort	UNGD activity metric – IDW well count (wells/mi) within 10-mile (52,800 ft; 16.1 km) radius of maternal residence	124,842 births 1996–2009 CDPHE Health Statistics, Colorado Responses to Children with Special Needs registry	Mother's age, education, ethnicity/race, child parity, tobacco and alcohol use, infant sex, residential elevation	**Highest exposure category vs. 0 wells within 10 miles (16.1 km)** Congenital heart defects ▲ (Increased prevalence of pulmonary artery and valve defects/PAV defects by 60%, ventricular septal defects/VSDs by 50%, tricuspid valve defects/ TVDs by 400%) Neural tube defects ▲ Oral clefts ▽ Preterm birth ▼ Term low birth weight ▼ Mean term birth weight ▲
McKenzie et al. (2019a)	34 CO counties with 20 or more wells drilled	Oil & natural gas	American Heart Association	Case-control (nested)	IA-IDW (well intensity/mi^2) considering wells and O&G facilities other than wells (compressor stations, tank farms, gathering lines) within 10-mile (52,800 ft) radius of each maternal residence	3,324 mother-infant pairs 2005–2011 Colorado Responds to Children with Special Needs birth defects registry	Mother's age, child parity, Socioeconomic status index, sex, IDW count of O&G facilities other than wells, IA-IDW count for air pollution sources not associated with O&G activities (continuous)	**Exposure during 3 months prior to conception:** Any congenital heart defects ▲ Aortic artery and valve defects △ Pulmonary artery and valve defects △ Conotruncal defects △ Tricuspid valve defects ▽ **Exposure during 2 months prior to conception:** Any congenital heart defects ▲ Aortic artery and valve defects △ Pulmonary artery and valve defects ▲ Conotruncal defects △ Tricuspid valve defects ▽

Author (Year)	Region	Primary hydro-carbon produced	Funder	Study design	Surrogate of exposure *(distance evaluated if specified)*	Sample size, study time frame, and outcome data source	Confounders and covariates considered	Main findings[1]
McKenzie et al. (2019a) *(continued)*	34 CO counties with 20 or more wells drilled	Oil & natural gas	American Heart Association	Case-control (nested)	IA-IDW (well intensity/mi^2) considering wells and O&G facilities other than wells (compressor stations, tank farms, gathering lines) within 10-mile (52,800 ft) radius of each maternal residence	3,324 mother-infant pairs 2005–2011 Colorado Responds to Children with Special Needs birth defects registry	Mother's age, child parity, Socioeconomic status index, sex, IDW count of O&G facilities other than wells, IA-IDW count for air pollution sources not associated with O&G activities (continuous)	**Exposure during 1 month prior to conception:** Any congenital heart defects ▲ Aortic artery and valve defects △ Pulmonary artery and valve defects △ Conotruncal defects △ Tricuspid valve defects ▽ **Exposure during 1st gestational month:** Any congenital heart defects ▲ Aortic artery and valve defects △ Pulmonary artery and valve defects △ Conotruncal defects △ Tricuspid valve defects ▽ **Exposure during 2nd gestational month**: Any congenital heart defects ▲ Aortic artery and valve defects △ Pulmonary artery and valve defects △ Conotruncal defects △ Tricuspid valve defects △
Erickson et al. (2022)	Five CO counties where hydraulic fracturing occurs	Un-conventional oil & natural gas	Not disclosed	Ecological	County-wide well density and production activity	252,502 birth records 1999–2019 CDPHE Vital Birth Statistics registry	Population density, age, gender, race, education, income	**High vs. low well density** Birthweight ▼ Prematurity ⬄ **High vs. low production** Birthweight ▼ Prematurity ⬄ **High vs. low well density/production** Birthweight ▼ Prematurity ▲

Author (Year)	Region	Primary hydro-carbon produced	Funder	Study design	Surrogate of exposure *(distance evaluated if specified)*	Sample size, study time frame, and outcome data source	Confounders and covariates considered	Main findings[1]
Ohio								
Gaughan et al. (2023)	Ohio	Unconventional oil & gas	U.S. EPA, NIH, Yale Cancer Center, National Cancer Institute	Retrospective	IDW[2] index within 5 km, and 10 km (6.2 mi) for active UOG wells; IDups: the inverse distance to the nearest upgradient active UOG well	965,236 live births 2010–2017 Ohio Department of Health Birth Records Ohio Connections for Children with Special Needs (OCCSN) birth defects surveillance system	infant sex, birth year, season of birth, maternal age, maternal race, maternal ethnicity, maternal educational attainment, maternal marital status, maternal smoking status during pregnancy, maternal alcohol use during pregnancy, parity (nulliparous, one or more previous live births), primary payer for delivery (Medicaid, private insurance), use of federal Women Infants and Children (WIC) program, pre-pregnancy body mass index (BMI), whether a mother received prenatal care, and maternal hypertension or diabetes, urbanicity/rurality, Social Vulnerability Index, air pollution ($PM_{2.5}$), nearby cropland	**Any UOG wells within 10 km (6.2 mi):** Any structural defect △ Any CHD △ Any NTD ▲ Oral clefts △ Limb reduction ▲ Hypospadias ▼

Author (Year)	Region	Primary hydro-carbon produced	Funder	Study design	Surrogate of exposure *(distance evaluated if specified)*	Sample size, study time frame, and outcome data source	Confounders and covariates considered	Main findings[1]
Oklahoma								
Apergis et al. (2019)	OK Statewide	Oil & natural gas	Not disclosed	Empirical analysis with Dumitrescu-Hurlin causality test and (long-run) Pooled Mean Group method	Number of conventional or unconventional (fracking) wells within 0–1 km (0–3,281 ft), 1–5 km (3,281–16,404 ft), 5–10 km (16,404–32,808 ft), or 10–20 km (32,808 ft–65,617 ft) of maternal residence	556,794 birth observations 2006–2017 Birth certificates from Oklahoma Health Department	Mother's age, education, ethnicity/race, child parity	**0–1 km (0–3,281 ft) from fracturing vs. > 20 km (65,617 ft):** Total birth weight ▼ Low birth weight ▲ Health index ▼ *Lower health index represents decline in infant health* **1–5 km (3,281–16,404 ft) from fracturing:** Total birth weight ▼ Low birth weight ▲ Health index ▼ **5–10 km (16,404–32,808 ft) from fracturing:** Total birth weight ▽ Low birth weight ▲ Health index ▼ **10–20 km (32,808 ft–65,617 ft) from fracturing:** Total birth weight ▽ Low birth weight △ Health index ▼ **0–1 km (0–3,281 ft) from conventional drilling vs. > 20 km:** Total birth weight ▽ Low birth weight △ Health index ▼ **1–5 km (3,281–16,404 ft) from conventional drilling:** Total birth weight ▽ Low birth weight △ Health index ▽ **5–10 km (16,404–32,808 ft) from conventional drilling:** Total birth weight ▽ Low birth weight ⇔ Health index ▽ **10–20 km (32,808 ft–65,617 ft) from conventional drilling:** Total birth weight ⇔ Low birth weight ⇔ Health index ▽

Author (Year)	Region	Primary hydro-carbon produced	Funder	Study design	Surrogate of exposure *(distance evaluated if specified)*	Sample size, study time frame, and outcome data source	Confounders and covariates considered	Main findings[1]
Janitz et al. (2019)	OK Statewide	Natural gas	NIH, National Institute of General Medical Sciences	Retrospective cohort	IDW well count of actively produced wells within 2 miles (3.2 km; 10,499 ft) of maternal residence during month of delivery	476,600 births 1997–2009 Oklahoma State Department of Health, Oklahoma Birth Defects Registry	Birth year, infant sex, maternal race/ethnicity, gestational age at delivery, birth weight, maternal age, marital status, parity, prenatal care, tobacco use during pregnancy, education	Neural tube defects △ Oral clefts ⇔ Congenital heart defects ▽ Common truncus △ Transposition of the great arteries △ Pulmonary valve atresia and stenosis△ Tricuspid valve atresia and stenosis △ Interrupted aortic arch △ Total anomalous pulmonary venous connection △ Double outlet right ventricle ▽ Ebstein's anomaly ▽ Hypoplastic left heart syndrome ▽ Coarctation of aorta ▽ Tetralogy of Fallot ▽
Pennsylvania								
Stacy et al. (2015)	Marcellus Shale, PA	Natural gas	Heinz Endowments	Retrospective cohort	IDW well count within 10 miles (52,800 ft; 16.1 km) of maternal residence	15,451 births 2007–2010 Pennsylvania Department of Health	Mother's age, education, pre-pregnancy weight, prenatal care, smoking status, gestational diabetes, WIC, race, child parity, infant sex	Small for gestational age ▲ Mean birth weight ▼ Preterm birth ⇔
Casey et al. (2016)	Central & Northeast PA	Natural gas	NIEHS, Degenstein Foundation, Robert Wood Johnson Foundation, NSF	Retrospective cohort	IDW[2] considering distance of well to maternal residence, phases of well activity (pad development, drilling, hydraulic fracturing, production volume)	10,946 neonates 2009–2013 Geisinger Health System	Neonate sex, gestational age, birth season/year, mother's age, race/ethnicity, insurance coverage, smoking status, BMI, parity, antibiotic use, receipt of medical assistance	Preterm birth ▲ High-risk pregnancy ▲ Low 5-min Apgar score ⇔ Small for gestational age ⇔ Mean term birth weight ▼ Mean term birth weight adjusted for birth year ⇔

Author (Year)	Region	Primary hydro-carbon produced	Funder	Study design	Surrogate of exposure *(distance evaluated if specified)*	Sample size, study time frame, and outcome data source	Confounders and covariates considered	Main findings[1]
Ma (2016)	Marcellus Shale PA	Natural gas	Not disclosed	Ecological	Zip code-level presence or absence of UOG wells spudded by conception date	1,401,813 births 2003–2012 Pennsylvania vital birth registry records (birth certificate data)	Maternal smoking status, age at delivery, highest education level, self-designated race, maternal pre-pregnancy body mass index, primary payor for delivery, WIC during pregnancy, pre- and during pregnancy diabetes status, hypertension status, infection during pregnancy status	**Zip codes with UNGD vs. zip codes without UNGD (adjusted OR)** Any birth defects ▲ Structural birth defects ▲ Functional or developmental birth defects ▲ **Zip codes with UNGD pre-drilling vs. zip codes with UNGD post-drilling (difference in prevalence rate)** Any birth defects ▼
Busby and Mangano (2017)	Marcellus Shale, PA	Natural gas	Not disclosed	Ecological	Rate ratio comparison (2007-2010 and 2003-2006) for 10 counties with highest UOG drilling activity, combined, regionally, and statewide	98,941 births and 431 infant deaths 2003–2010 Pennsylvania Department of Health (PADOH)	Not considered	**Early infant deaths** 10 counties with heaviest fracking activity ▲ 5 northeastern fracked counties ▲ 5 southwestern counties ▲
Currie et al. (2017)	PA Statewide	Oil and natural gas	John D. & Catherine T. MacArthur Foundation, US EPA	Retrospective cohort & difference-in-differences	Proximity of maternal residence to wells where conception occurs after spud date — buffer of 0–1 km (0–3,281 ft) as "Near", and 3–15km (9,843–49,213 ft) as "Far"	1,125,748 births 2004–2013 Certificate of Live Births	Mother's age, education, ethnicity/race, marital status, child parity	**0–1 km (0–3,281 ft) vs 3–15 km (9,843–49,213 ft)** Low birth weight ▲ Mean term birth weight ▼ Infant health index ▼ *Lower health index represents decline in infant health*
Hill (2018)	PA Statewide	Natural gas	Cornell Population Center	Retrospective cohort & differences in differences	Proximity of maternal residence to wells (<2km, <2.5km, <3km, <3.5km, <4km, <4.5km, <5km) (<6,562–16,404 ft) and well density at 2.5 km (8,202 ft). Birth pre-drilling (unexposed) and post drilling (exposed).	1,098,884 births 2003–2010 Vital statistics natality & mortality data	Mother's age, education, ethnicity/race, marital status, WIC status, insurance type, previous risky pregnancy, smoking status, birth month/year, gender	**2.5 km (8,202 ft) of a well compared to 2.5 km (8,202 ft) of a permitted, but not yet drilled, well** Low birth weight ▲ Mean term birth weight ▼ Small for gestational age ▲ Apgar score <8 ▲

Author (Year)	Region	Primary hydro-carbon produced	Funder	Study design	Surrogate of exposure *(distance evaluated if specified)*	Sample size, study time frame, and outcome data source	Confounders and covariates considered	Main findings[1]
Hill (2018) *(continued)*	PA Statewide	Natural gas	Cornell Population Center	Retrospective cohort & differences in differences	Proximity of maternal residence to wells (<2km, <2.5km, <3km, <3.5km, <4km, <4.5km, <5km) (<6,562–16,404 ft) and well density at 2.5 km (8,202 ft). Birth pre-drilling (unexposed) and post drilling (exposed).	1,098,884 births 2003–2010 Vital statistics natality & mortality data	Mother's age, education, ethnicity/race, marital status, WIC status, insurance type, previous risky pregnancy, smoking status, birth month/year, gender	**Well density at 2.5 km (8,202 ft)** Low birth weight ▲ Mean term birth weight ▼ Premature birth ▲
Texas								
Whitworth et al. (2017)	Barnett Shale, TX	Natural gas	NIEHS, NIOSH	Retrospective cohort	UNGD-activity metrics - IDW sum of active wells ½ mile (2,640 ft; 0.8 km), 2 miles (10,560 ft; 3.2 km), 10 miles (52,800 ft; 16.1 km) from material residence	158,894 births 2010–2012 Texas Department of State Health Services	Mother's age, race/ethnicity, education, BMI, parity, smoking, prenatal care, previous risky pregnancy, infant sex	**1/2 mile (2,640 ft; 0.8 km):** Preterm birth ▲ SGA ⇔ Fetal deaths △ Mean birth weight ⇔ **2 miles (10,640 ft; 3.2 km):** Preterm birth ▲ SGA ▽ Fetal deaths △ Mean birth weight ▽ **10 miles (52,800 ft; 16.1 km):** Preterm birth ▲ SGA ▽ Fetal deaths ▲ Mean birth weight ▽
Walker Whitworth et al. (2018)	Barnett Shale, TX	Natural gas	NIH, NIEHS, NIOSH	Case-control	UNGD-activity metric – IDW[2] count of wells in drilling phase within ½ mile (2,640 ft; 0.8 km) of maternal residence; sum of IDW sum of natural gas produced from wells within ½ mile (2,640 ft; 0.8 km) of maternal residence	163,827 births 2010–2012 Texas Department of State Health Services	Mother's age, race/ethnicity, education, parity, smoking status, BMI, infant sex, previously poor pregnancy outcome, prenatal care	**Drilling/Production (all pregnancy):** All Preterm birth ▲ Extremely Preterm birth ▲ Very Preterm birth △ Moderately Preterm birth ▲ **Drilling** **1st or 2nd trimester:** All Preterm birth ▲ **3rd trimester:** All Preterm birth △

Author (Year)	Region	Primary hydro-carbon produced	Funder	Study design	Surrogate of exposure *(distance evaluated if specified)*	Sample size, study time frame, and outcome data source	Confounders and covariates considered	Main findings[1]
Walker Whitworth et al. (2018) *(continued)*	Barnett Shale, TX	Natural gas	NIH, NIEHS, NIOSH	Case-control	UNGD-activity metric – IDW[2] count of wells in drilling phase within ½ mile (2,640 ft; 0.8 km) of maternal residence; sum of IDW sum of natural gas produced from wells within ½ mile (2,640 ft; 0.8 km) of maternal residence	163,827 births 2010–2012 Texas Department of State Health Services	Mother's age, race/ethnicity, education, parity, smoking status, BMI, infant sex, previously poor pregnancy outcome, prenatal care	<u>**Production:**</u> **1st trimester:** All Preterm birth ▲ **2nd trimester:** All Preterm birth △ **3rd trimester** All Preterm birth ▽
Cushing et al. (2020)	Eagle Ford Shale, TX	Oil & gas	NIH, NIEHS	Retrospective cohort	Number of wells and number of satellite observations of flaring activity during pregnancy within 5 km (16,404 ft) of maternal residence	23,487 births 2012–2015 Texas Department of State Health Services Center for Health Statistics	Mother's age, education, ethnicity/race, BMI, birthplace, prenatal care usage, smoking status, insurance coverage, child parity, birth year/season, high-risk pregnancy	*Results from adjusted model (Model 2) shown below* **27-954 wells within 5 km (16,404 ft) vs. 0 wells:** Preterm birth ▲ Small for gestational age ⇔ Gestational age in days ▼ Mean term birth weight ▼ **≥10 flares within 5 km (16,404 ft) vs. 0 flares:** Preterm birth ▲ Small for gestational age ⇔ Gestational age in days ▼ Mean term birth weight ▽
Tang et al. (2021)	TX Statewide	Natural gas	UC Irvine Program in Public Health	Case-control	Yearly active well density within 1 km (3,281 ft), 3 km (9,843 ft), and 7.5 km (24,606 ft) of maternal residence for year of birth	52,995 cases 642,399 controls 1999–2011 Texas Department of State Health Services Texas Birth Defects Registry	Mother's smoking status, plurality of birth, age, race/ethnicity, education status, median household income, urbanicity in 2010, average daily vehicle miles traveled for all trucks by county	*p-values for trend tests of adjusted odds ratios, p <0.01 below* **Well density within 1 km (3,281 ft) buffer, 3 km (9,843 ft) buffer, and 7.5 km (24,606 ft) buffer:** Atrial Septal Defect ▲ Aortic Valve Stenosis ▲ Hypoplastic Left Heart Syndrome ▲ Pulmonary Valve Atresia/Stenosis ▲ Ventricular Septal Defect ▲ **Well density within 1 km buffer:** Anencephaly ▲ Tricuspid Valve Atresia/Stenosis ▲

Author (Year)	Region	Primary hydro-carbon produced	Funder	Study design	Surrogate of exposure *(distance evaluated if specified)*	Sample size, study time frame, and outcome data source	Confounders and covariates considered	Main findings[1]
Willis et al. (2021)	TX Statewide	Oil & gas	NIH, NIEHS, NCATS	Retrospective cohort & difference-in-differences	Residential proximity near [0–1 km (0–3,281 ft), 1–2 km (3,281–6,562 ft), 2–3 km (6,562–9,843 ft)] vs. far [3–10 km (9,843 ft–32,808 ft)] from active/future drill site; births before drilling (unexposed) vs. births during drilling (exposed)	2,598,025 mother-infant pairs 1999–2009 Texas Department of State Health Services Vital Statistics Program	Birth year/month, infant sex, mother's age, race/ethnicity, & educational attainment, nulliparous, prenatal care received, smoking during pregnancy, weight gain during pregnancy, diabetes diagnosis, gestational hypertension diagnosis, eclampsia diagnosis, infant gestational age, regional location, income, employment, distance to highways, census place	**Mothers living 0–1 km (0–3,281 ft) vs. 3–10 km (9,843 ft–32,808 ft) from current/future drilling site (Model 3)** Term birth weight ▼ Small for gestational age ⇔ **1–2 km (3,281–6,562 ft) & 2–3 km (6,562–9,843 ft) vs. 3–10 km (9,843 ft–32,808 ft) from current/future drilling site** Term birth weight ▼ Small for gestational age ⇔
Willis et al. (2022)	TX Statewide	Oil & gas	NIH, NIEHS, NCATS	Retrospective cohort & difference-in-differences	Residential proximity near [0–1 km (0–3,281 ft), 1–2 km (3,281–6,562 ft), 2–3 km (6,562–9,843 ft)] vs. far [3-10 km (9,843 ft–32,808 ft)] from active/future drill site; births before drilling (unexposed) vs. births during drilling (exposed)	2,845,144 mothers 1999–2009 Texas Department of State Health Services Vital Statistics Program	Birth year/month, infant sex, gestational age, mother's age, race/ethnicity, mother's education, nulliparous, prenatal care received, smoking and mother's weight during pregnancy, distance to major roadways	**Mothers living 0–1 km (0–3,281 ft) vs. 3–10 km (9,843 ft–32,808 ft) from current/future drilling site (Fully adjusted model)** Gestational hypertension ▲ Eclampsia ▲ **1–2 km (3,281–6,562 ft) vs. 3–10 km (9,843 ft–32,808 ft) from current/future drilling site** Gestational hypertension ⇔ Eclampsia △ **2–3 km (6,562–9,843 ft) vs. 3–10 km (9,843 ft–32,808 ft) from current/future drilling site** Gestational hypertension ⇔ Eclampsia ⇔

Author (Year)	Region	Primary hydro-carbon produced	Funder	Study design	Surrogate of exposure *(distance evaluated if specified)*	Sample size, study time frame, and outcome data source	Confounders and covariates considered	Main findings[1]
Han et al. (2023)[2]	Barnett Shale, TX (Denton, Johnson, Tarrant, Wise Counties)	Hydraulic fracturing	None	Ecological	Billions cubic feet gas produced from hydraulic fracturing per county	1999–2014 Texas Birth Defects Registry Four counties versus statewide rates	county, time period	**Standardized Morbidity Ratios (SMR) of total birth defects:** **Denton County:** 1999-2002 ⇔ 2003-2006 ⇔ 2007-2010 ⇔ 2011-2014 ⇔ **Johnson County:** 1999-2002 ⇔ 2003-2006 ▲ 2007-2010 ▲ 2011-2014 ▲ **Tarrant County:** 1999-2002 ▲ 2003-2006 ▲ 2007-2010 ▲ 2011-2014 ▲ **Wise County:** 1999-2002 ⇔ 2003-2006 ▲ 2007-2010 ⇔ 2011-2014 ⇔
Willis et al. (2023)	TX	Oil & gas	NIH	Retrospective cohort	IDW[2] index within 5 km (16,4040 ft) for drilling site count, gas production, oil production, and produced water	2,234,138 births 86,315 cases 2,147,823 controls 1999–2009 Texas Department of State Health Services Vital Statistics Database & Birth Defects Registry	infant sex, gestational age, birth weight, maternal age, maternal race and ethnicity, maternal education, maternal smoking, maternal alcohol usage, prenatal care initiated, census tract unemployment, census tract percent White population, census tract median household income, distance to nearest highways, birth year, county	**Temporal comparison, IDW[2] well count within 5 km (16,404 ft):** All defects ▲ > 1 site ▲ Cardiac and circulatory ▲ Central nervous system ⇔ Eye and ear ▲ Gastrointestinal ⇔ Genitourinary ▲ Musculoskeletal ⇔ Oral clefts ⇔ Respiratory ⇔ Chromosomal ↑▲

[1] Associations from studies that tested for statistical significance are represented using the following symbols: ▲=significant increase, ▼= significant decrease, ▽= non-significant decrease, △= non-significant increase, ⇔ = null findings/no association. Studies that did not test for statistical significance are noted in the table and results are briefly summarized. Unless explicitly stated, the summary of outcomes represents results from comparing the highest tertile/quantile/quartile/highest exposure category to the lowest exposure category. In other words, the increase or decrease in a health outcome is the highest exposure group compared to the lowest (or reference category).

[2] Han et al. (2023). For findings from this study for specific congenital anomalies by year and by county, please see Han et al. (2023), Table 4.

Abbreviations**:** Barrels of oil and barrels of oil equivalent natural gas (BOE); body mass index (BMI); California Air Resources Board (CARB); Colorado Department of Public Health and the Environment (CDPHE); inverse distance weighted (IDW); intensity adjusted inverse distance weighted well intensity (IA-IDW); National Center for Advancing Translational Science (NCATS); National Institute for Occupational Safety and Health (NIOSH); National Institute of Environmental Health Sciences (NIEHS); National Institutes of Health (NIH); National Science Foundation (NSF); California Office of Statewide Health and Planning (OSHPD); Pennsylvania Department of Health (PADOH); Systems Approach to Green Energy-Integrative Graduate Education and Research Traineeship (SAGE-IGERT); University of California (UC); unconventional natural gas development (UNGD), unconventional oil and gas (UOG); United States Environmental Protection Agency (US EPA).

3.3.2.3 Respiratory outcomes

Eleven studies examine the association between upstream OGD and respiratory outcomes (Bushong et al., 2022; Johnston et al., 2021; Koehler et al., 2018; Li et al., 2023; Peng et al., 2018; Rabinowitz et al., 2015; Rasmussen et al., 2016; Shamasunder et al., 2018; Willis et al., 2018; 2020; Trickey et al., 2023). Two studies were conducted in California (described directly below: Johnston et al., 2021; Shamasunder et al., 2018) and nine studies were conducted in other oil and gas regions, including Pennsylvania (Bushong et al., 2022; Koehler et al., 2018; Peng et al., 2018; Rabinowitz et al., 2015; Willis et al., 2018), Texas (Li et al., 2023; Willis et al., 2020), and across multiple states (Pennsylvania and New York: Rasmussen et al., 2016; Trickey et al., 2023). These studies evaluate potential exposures and respiratory outcomes from 2005 to 2019.

Below we first present studies conducted in California, and then discuss findings regarding the most examined respiratory outcome, asthma.

Respiratory outcome studies conducted in California

Two studies conducted in California evaluated the associated upstream OGD and respiratory outcomes (Shamasunder et al., 2018; Johnston et al., 2021). These studies focused on upstream OGD exposures and respiratory outcomes between 2016 and 2019.

Shamasunder et al. (2018)

Shamasunder et al. (2018) conducted household health surveys between March and May 2016 using questions from a validated health questionnaire within two 1,500 ft (457 m) buffer areas surrounding the Jefferson and AllenCo oil production sites in the City of Los Angeles. The authors found that self-reported physician-diagnosed asthma rates were elevated within both buffer zones compared to sub-county and county-level surveys (e.g., the California Health Interview Survey of Service Planning Area 6). Asthma prevalence was higher in one buffer zone (West Adams near the Jefferson drill site) than in Los Angeles County in aggregate. The authors reported that 45% of residents surveyed were unaware of nearby oil development. The study also included *in situ* monitoring for methane near a site with oil wells. Prior research has found that methane emissions from oil and gas wells are associated with emissions of air toxics, including non-methane volatile organic compound (VOC) emissions. However, there were no efforts to determine the source of emissions as part of this study. Subsequent studies have reported elevated concentrations of ambient air pollutants, including non-methane VOCs, near oil and gas wells in Los Angeles (Collier-Oxandale et al., 2020; Garcia-Gonzales et al., 2019; Gonzalez et al., 2022; Okorn et al., 2021). While this study compared localized asthma rates to sub-county and county-level surveys, the authors were not able to control for additional sources of air pollution or other variables associated with asthma prevalence. It also relies on self-reported data, which can be subject to bias.

Johnston et al. (2021)

Johnston et al. (2021) evaluated lung function and self-reported acute health symptoms among residents living near one active oil development site and one idle oil development site in the Las

Cienegas oil field in South Los Angeles between January 2017 and August 2019. The authors used a cross-sectional study design: an observational study comparing measured health outcomes at one time point (i.e., without assessing temporal variation). Johnston et al. (2021) surveyed 961 study participants ages 5 and over who were residents living within 1 km (3,281 ft) of an *active* oil development site (with 28 wells) in the Jefferson Park neighborhood and within 1 km (3,281 ft) of an *idle* oil development site (with 21 wells) in the North University Park neighborhood. Additionally, the authors assessed lung function of 747 residents using spirometry. Residents living near the active oil development site self-reported significantly higher odds of recent wheeze, sore throat, chest tightness, eye and nose irritation, dizziness, and ringing of the ears as compared to residents living near the idle oil development site. Residents who lived closer to both oil development sites had reductions in lung function; lung function decreased for every 100 m (328 ft) closer to the site. The investigators also assessed differences in lung function between participants living at distances of <150 m (492 ft), <200 m (656 ft), and <400 m (1,312 ft) from the active and idle oil development sites compared to those living farther away. They also evaluated differences in lung function among participants living downwind from wells out to 1 km (3,281 ft) from oil development sites (the farthest distance assessed), compared to residents living less than 1 km (3,281 ft) and upwind from the oil development sites. Across all analyses, participants living closer to both oil development sites (active and idle) had reductions in lung function. The reduction in lung function was greatest among participants living near and downwind of the active oil development site compared to the idle oil development site. The findings of reduced lung function among residents downwind of oil and gas wells, compared to those living farther away and upwind, were adjusted for participant age, height, weight, sex, race/ethnicity, proximity to freeway, recent cold/flu, asthma status, smoking status, indoor exposure to environmental tobacco smoke, and season.

Asthma

Asthma is the most commonly studied respiratory health outcome in the epidemiological literature focused on upstream OGD. Eight studies conducted outside of California examined asthma exacerbations and hospitalizations, with five focused in Pennsylvania, one focused in Pennsylvania and New York (multiple states), and two focused in Texas (Bushong et al., 2022; Koehler et al., 2018; Li et al., 2023; Peng et al., 2018; Rabinowitz et al., 2015; Rasmussen et al., 2016; Willis et al., 2020, 2018). These studies examined upstream OGD and asthma-related outcomes between 2000 and 2014.

Studies in Pennsylvania have found that upstream OGD is associated with increased pediatric hospitalizations for asthma, increased rates of mild asthma exacerbations[8], and increased rates of lower respiratory symptoms, including mild asthma exacerbations[9] (**Figure 3.9**) (Koehler et al., 2018; Peng et al., 2018; Rabinowitz et al., 2015; Rasmussen et al., 2016; Willis et al., 2018). Consistent with findings observed from studies focused on Pennsylvania, in Texas, Willis et al. (2020) also observed an increased odds of pediatric asthma hospitalizations associated with natural gas development, for both conventional drilling and unconventional drilling activities, and

[8] Defined by the presence of new oral corticosteroid prescriptions.
[9] Defined as new oral corticosteroid medication orders, asthma/COPD, chronic bronchitis, chest wheeze/whistling, shortness of breath, and/or chest tightness.

increased well production volumes. Furthermore Li et al. (2023) observed an increase in asthma rates in census block with higher counts of oil and natural gas wells in Texas.

As shown in **Figure 3.9** below, two studies conducted in Pennsylvania found an association with increased rates of mild asthma exacerbations and oil and gas exposure within 1 km (3,281 ft) of a well compared to those living greater than 2 km (1.2 mi) away (Koehler et al., 2018; Rabinowitz et al., 2015). This is consistent with another Pennsylvania study, which found a significant positive association between asthma hospitalization rates and annual well density (Bushong et al., 2022). Similarly, Rasmussen et al. (2016) found that those living next to the densest areas of oil and gas production in the Marcellus Shale region had significantly increased odds of mild asthma exacerbation compared to those living near lower-density activity. This result was found to be significant during all four phases of development (pad development, drilling, stimulation, and production). In addition to mild asthma exacerbations, Rasmussen et al. (2016) also found that those living in the highest quartile of residential unconventional natural gas development activity for all four phases (pad development, drilling, stimulation, production) had significantly higher odds of moderate and severe types of asthma exacerbations (emergency department visits, and hospitalizations, respectively) than those in the lowest quartile.

This is consistent with another Pennsylvania study (Willis et al., 2018), which found a significant positive association between pediatric asthma hospitalization rates and annual well density. Using a similar methodological approach in Texas, Willis et al. (2020) also found that both conventional and unconventional natural gas development at the ZIP code level was associated with pediatric asthma hospitalizations. Overall, all studies found upstream OGD was associated with increased asthma-related outcomes.

Study (Year)	State	Years of Data	Hydrocarbon Type	Exposure Metric	Radius*	Comparison	Exposure Category**
Koehler et al. (2018)	PA	2005 - 2013	Natural gas	DNDW	<3,281 ft	Distance > 2km	High (Distance <1 km)
							Medium (Distance 1-2 km)
				IDW (distance)	<52,800 ft	0 wells (<10 mi)	3rd tertile (drilling)
							2nd tertile
							1st tertile
				IDW (squared-distance)	<52,800 ft	1st quartile (all phases)	4th quartile (all phases)
							3rd quartile
							2nd quartile
Rabinowitz et al. (2015)	PA	2012	Natural gas	DNDW	<6,562 ft	Distance > 2km	High (Distance <1 km)
							Medium (Distance 1-2 km)
Rasmussen et al. (2016)	PA & NY	2005 - 2012	Natural gas	IDW (squared-distance)	None	Very Low (<10.7 wells/m2)	High (>48.7/m2)
							Medium (25.8-48.7/m2)
							Low (10.7-25.7/m2)
						Very Low (<5.1wells/m2)	High (>66.8/m2)
							Medium (32.4-66.8/m2)
							Low (5.1-32.3/m2)
						Very Low (<2.7 m well depth/m2)	High (>67.4 m/m2)
							Medium (25.6-67.4 m/m2)
							Low (2.7-25.5 m/m2)
						Very Low (<2.3 m3 production volume/m2)	High (>759.7 m3/m2)
							Medium (133.3-759.7 m3/m..
							Low (2.3-133.2 m3/m2)
Willis et al. (2018)	PA	2003 - 2014	Natural gas	Production activity	None	No production	High
							Medium
							Low
Willis et al. (2020)	TX	2000 - 2010	Natural gas	All production activity	None	No production	High (All)
							Medium (All)
							Low (All)
				Conventional drilling activity	None	No conventional drilling	High (Conventional)
							Medium (Conventional)
							Low (Conventional)
				Unconventional drilling activity	None	No unconventional drilling	High (Unconventional)
							Medium (Unconventional)
							Low (Unconventional)
				Flaring volume	None	0 flaring volume	High (Flaring)
							Medium (Flaring)
							Low (Flaring)
				Production volume	None	0 production volume	High (Production)
							Medium (Production)
							Low (Production)

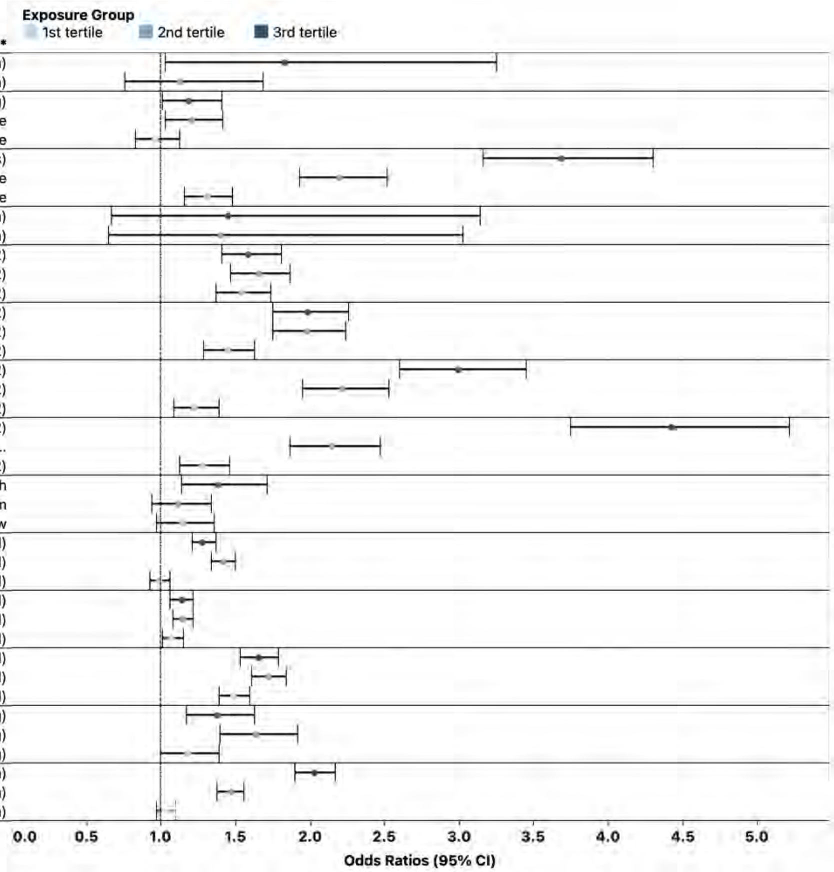

Figure 3.9. Summary of epidemiological studies on associations in between upstream oil and gas development and lower respiratory effects, including but not limited to mild asthma exacerbations and asthma-related hospitalizations.

* Radius represents the distance used to define exposed individuals. Studies that have no radius did not utilize a buffer distance when defining their study population.

** The exposure category represents the name of the category as defined by the original study. To provide visual comparability, we standardized each exposure group to tertiles, with the 1st tertile representing low activity, the 2nd tertile representing medium activity, and the 3rd tertile representing high activity. Quantiles/quartiles were fitted in the same fashion.

Note: Results from Shamasunder et al. (2018), Bushong et al. (2022), Li et al. (2023), and Trickey et al. (2023) did not include estimated odds ratios (or risk ratios) and were therefore excluded from the figure.

Abbreviations: DNDW = distance to nearest drilled well; IDW = inverse distance weighted; mild asthma exacerbations = new oral corticosteroid medication orders; lower respiratory symptoms = mild asthma exacerbations defined as new oral corticosteroid medication orders, asthma/COPD, chronic bronchitis, chest wheeze/whistling, shortness of breath, or chest tightness.

Table 3.4. Summary of epidemiological studies on association between upstream oil and gas development and adverse respiratory health outcomes in the United States. Studies are categorized by state and then chronologically by publication year.

Author (Year)	Region	Primary hydro-carbon produced	Funder	Study design	Surrogate of exposure *(distance evaluated if specified)*	Sample size, study time frame, and outcome data source	Confounders and covariates considered	Main findings[1]
California								
Shama-sunder et al. (2018)	South Los Angeles, CA West Adams & University Park	Oil	11th Hour Project, NSF	Self-reported survey (validated question-naire; physician - reported asthma)	1,500 ft (457 m) buffer around two oil development sites.	205 surveys at randomly sampled residences 813 residents March–May 2016 Self-reported outcome	Not considered	**1,500 ft (457 m) from site vs. Los Angeles County:** Asthma diagnosis ▲ (West Adams) Asthma diagnosis △ (University Park) Asthma emergency department visit ⬄ **1,500 ft (457 m) from site vs. California Health Interview Survey of Service Planning Area 6 (SPA6):** Asthma diagnosis ▲ (West Adams & University Park) Asthma emergency department visit ⬄
Johnston et al. (2021)	South Los Angeles, CA North University Park & Jefferson Park	Oil	NIEHS	Cross-sectional (self-reported survey with lung function measurements)	1 km (3,281 ft) buffer around two oil development sites, one with 28 active wells (Jefferson Park) and one with 21 idle wells (North University Park)	961 residents from 488 addresses 747 valid spirometry tests 2017–2019 Self-reported symptoms & spirometry measurements	Age, sex, height, age-height interaction, race/ethnicity, weight, recent flu/cold, proximity to freeway, asthma status smoking status, indoor exposure to environmental tobacco smoke, season, wind direction (downwind vs. upwind)	**Lung function findings** Significantly lower lung function was found among residents living near O&G development (<200 m, 656 ft) and downwind (200–1,000 m, 656–3,281 ft). **For self-reported acute health symptoms findings, see Table 3.8.**

Author (Year)	Region	Primary hydro-carbon produced	Funder	Study design	Surrogate of exposure *(distance evaluated if specified)*	Sample size, study time frame, and outcome data source	Confounders and covariates considered	Main findings[1]
Pennsylvania								
Rasmussen et al. (2016)	Marcellus Shale (PA, NY)	Natural gas	NIEHS, Degenstein Foundation, Robert Wood Johnson Foundation, NSF	Case-control (nested)	UNGD activity metric – IDW[2] method considering pad preparation, spud, stimulation, and production phases *Patients in the highest exposure group lived a median of 19 km (62,336 ft) from closest well vs. 63 km (206,693 ft) for patients in the lowest group.	35,508 patients 2005–2012 Geisinger Health System	Age, season, smoking status, obesity status, medical assistance, type 2 diabetes, sex, race/ethnicity	**Pad:** Asthma hospitalizations ▲ Asthma emergency department visits △ Oral corticosteroid medication orders ▲ **Spud:** Asthma hospitalizations ▲ Asthma emergency department visits ▲ Oral corticosteroid medication orders ▲ **Stimulation:** Asthma hospitalizations ▲ Asthma emergency department visits ▲ Oral corticosteroid medication orders ▲ **Production:** Asthma hospitalizations ▲ Asthma emergency department visits ▲ Oral corticosteroid medication orders ▲
Koehler et al. (2018)	Northeast, Northcentral, Northwest, Southwest PA	Natural gas	NIEHS, Degenstein Foundation, Robert Wood Johnson Foundation, NSF	Case-control	DNDW (distance to nearest drilled well) < 1 km (3,281 ft) to >2 km (6,562 ft) IDW considers drilling phase for wells <10 miles (52,800 ft) of residence; IDW[2] considers four phases: pad preparation, drilling, stimulation, production, & compressors	13,196 cases 18,693 controls 2005–2013 Geisinger Health System *Study relied on data from Rasmussen et al. (2016) but was considered a separately published analysis as it utilized different exposure assessment strategies.*	Age, sex, race/ethnicity, history of asthma, smoking status, season, medical assistance, obesity status, distance/distance-squared to nearest major and minor arterial roads, max temperature and max temperature-squared on the day prior to the event, community socioeconomic deprivation	**DNDW <1 km (3,281 ft) vs. >2 km (6,562 ft):** Oral corticosteroid medication orders ▲ **IDW (Drilling):** Oral corticosteroid medication orders ▲ **<u>IDW[2]:</u>** **All phases & compressor engines:** Oral corticosteroid medication orders ▲ **Production volume only:** Oral corticosteroid medication orders ▲

Author (Year)	Region	Primary hydro-carbon produced	Funder	Study design	Surrogate of exposure *(distance evaluated if specified)*	Sample size, study time frame, and outcome data source	Confounders and covariates considered	Main findings[1]
Peng et al. (2018)	Marcellus Shale, PA	Unconven-tional natural gas	Not disclosed	Difference-in-differences	County-level active well count	804 observations 2001–2013 Pennsylvania Health Care Cost Containment Council	County-level proportion of type of insurance, female patients, race/ethnicity, types of admission; county-level Charlson index, unemployment rate, poverty rate, median household income, population density, coal production, number of conventional wells, conventional production, age-distribution	**Well drilled in the last year (year fixed effects, county specific linear trends)** *Full sample (Age 5+) & partial (Age 65+)* Pneumonia ▲ Acute myocardial infarction ⇔ COPD ⇔ Asthma ⇔ Upper respiratory infections ⇔
Willis et al. (2018)	Rural counties located in Marcellus Shale, PA	Unconven-tional natural gas	NIH Office of the Director	Difference-in-differences	Newly spudded wells, ever-spudded wells, cumulative count of wells ever drilled by zip code for unconventional and/or conventional oil and gas development.	15,837 pediatric asthma-related hospitalizations 2003–2014 Pennsylvania Health Care Cost Containment Council Inpatient Discharge Data	Non-UNGD respiratory hazards	**Highest tertile of exposure to unconventional drilling vs. unexposed** Pediatric asthma hospitalizations ▲ **Newly spudded wells** Pediatric asthma hospitalizations ▲ **Ever-spudded wells in zip code** Pediatric asthma hospitalizations ▲
Bushong et al. (2022)	PA Statewide	Unconven-tional oil & natural gas	NIH	Difference-in-differences	Cumulative annual well density at the county-level	62 of 67 counties 2001–2014 PA-DOH & PA-DEP asthma hospitalization rates	$PM_{2.5}$ pollution, smoking prevalence, people <65 years old who are uninsured, household income, race/ethnicity, educational attainment	**Increased well density in urban & rural counties:** Asthma hospitalization rate ▲
Trickey et al. (2023)	Three Northern Pennsylva nia Counties and eight New York Counties	Unconven-tional oil & gas	University of Chicago and Argonne National Laboratories	Difference-in-differences	UOG activity in zip code (binary variable)	61,152 Medicare enrollees in 2015 2002–2015 Hospitalisation data (MedPAR) of 100% of Medicare fee-for-service beneficiaries	None. Modeling method controls for time-invariant confounders by design.	**Any diagnosis of COPD and bronchiectasis (hospitalizations):** 2010 ⇔ 2011 ⇔ 2012 ▲ 2013 ▲ 2014 ▲ 2015 ⇔

Author (Year)	Region	Primary hydro-carbon produced	Funder	Study design	Surrogate of exposure *(distance evaluated if specified)*	Sample size, study time frame, and outcome data source	Confounders and covariates considered	Main findings[1]
Texas								
Willis et al. (2020)	Zip codes overlaying shale regions, TX	Natural gas	NIH, NIEHS, NCATS	Ecological	Cumulative count of natural gas drilling sites per km^2 in zip code by quarter, with vertical vs. horizontal/directional sub-analysis; volume of natural gas flared (MCF) in zip code per quarter; volume of natural gas produced (MCF) in zip code by quarter	54,956 hospitalizations in 1,249 zip codes 2000–2010 Texas Department of State Health Services Inpatient Public Use Data File	Population density <18 years old, percent population identifying as Hispanic, NATA respiratory hazard index, percent unemployed, percent of population below poverty line, median household income, count of spudded drilling sites by zip code from 1990–1999	*Temporal & spatial fixed effects model (Model 3) results shown below* **Pediatric asthma hospitalizations** All drilling ▲ Conventional △ Unconventional ▲ Flaring volume ▼ Production volume ▲
Li et al. (2023)	(Dallas/Fort Worth Metropolitan Area (Collin, Dallas, Denton, and Tarrant Counties)	Natural gas	None declared	Spatial cluster analysis of census tracts, Cross Sectional	Urban gas drilling: Aggregated counts of wells in census block group (not clear if these were well being drilled)	Asthma hospital visits for adults (18–65 years). No population size provided. 2014 Dallas/Fort Worth Hospital Council Foundation hospital records	Age, socio-economic characteristics, transportation, housing conditions, and land use	**Incidence of adult asthma exacerbations (Model 4) by demographic variable:** # Adult males ⇔ # Black ▲ Median HH income ▼ # No HS diploma ▲ Adult density ▼ Median age ▼ Well counts ▲ Proximity to HWY ⇔ AVG speed ⇔ Road density ▲ AVG COM distance ▲ # Work at home ▼ #Pub transit users ▲ House before 1979 ▲ Gas heating house ▲ Elec heating house ▲ Park/Rec density ⇔ Tim/farm density ▼

[1] Associations from studies that tested for statistical significance are represented using the following symbols: ▲=significant increase, ▼= significant decrease, ▽= non-significant decrease, △= non-significant increase, ⇔ = null findings/no association. Studies that did not test for statistical significance are noted in the table and results are briefly summarized. Unless explicitly stated, the summary of outcomes represents results from comparing the highest tertile/quantile/quartile/highest exposure category to the lowest exposure category. In other words, the increase or decrease in a health outcome is the highest exposure group compared to the lowest (or reference category).

Abbreviations: COPD (chronic obstructive pulmonary disease); thousand cubic feet (MCF); National Air Toxics Assessment (NATA); National Center for Advancing Translational Science (NCATS); National Institute of Environmental Health Sciences (NIEHS); National Institutes of Health (NIH); National Science Foundation (NSF); Pennsylvania Department of Environmental Protection (PADEP); Pennsylvania Department of Health (PADOH); unconventional natural gas development (UNGD).

3.3.2.4 Mental and behavioral health outcomes

Six studies evaluated the association between upstream OGD and mental and behavioral health outcomes between 2002 and 2019 (Aker et al., 2022; Casey et al., 2018a; Casey et al., 2018b; Casey et al., 2019; Elser et al., 2023; Mayer & Olson Hazboun, 2019; **Table 3.5**). No studies on mental or behavioral health outcomes were conducted in California.

In Pennsylvania, Casey et al. (2018b) found that exposure to unconventional natural gas development was associated with mild depressive symptoms and overall depression symptoms among adults in the highest exposure category as compared to the lowest exposure category. Casey et al. (2018b) also examined disordered sleep among adults but found no association between exposure to unconventional OGD and disordered sleep. Also in Pennsylvania, Casey et al. (2019) found that antenatal anxiety and depression was associated with exposure to unconventional natural gas development among mothers in the highest exposure category, with a stronger association observed among mothers receiving medical assistance (an indicator of low family income).

One study conducted in British Columbia, Canada, examined the association between proximity and density of unconventional natural gas wells and mental illness and substance use among mothers who gave birth between 2006 and 2016 using an IDW metric (Aker et al., 2022). Results from this study show that the second and third quartiles of the 10 km (32,808 ft) IDW are associated with increased odds of depression when compared to the first quartile. This association was not found when comparing the fourth quartile to the first, however. Furthermore, the authors found no significant associations for the 2.5 km (8,202 ft) IDW exposure metric (Aker et al., 2022). Another study examining alcohol consumption and oil and gas production across the United States found county-level oil production was associated with a slight, but statistically non-significant increase in heavy drinking and binge drinking among males in the United States (Mayer & Olson Hazboun, 2019). This study reported no association with gas production and a slight, but non-significant decrease in alcohol consumption among females (Mayer & Olson Hazboun, 2019).

Seismic activity has increased in Oklahoma and other states due to wastewater injection from OGD activities (Alghannam, 2020; Keranen et al., 2008; Weingarten et al., 2015). In Oklahoma, Casey et al. (2018a) found a positive association between the occurrence of upstream OGD related earthquakes and Google searches focused on anxiety, suggesting that seismic activity induced by oil and gas-related wastewater injection may elicit a psychological response in Oklahoma residents. Additionally, Elser et al (2023) undertook a retrospective cohort study with repeated measures to evaluate the association between felt earthquakes (≥magnitude 4) and anxiety disorders in Oklahoma between 2010 and 2019. Results showed a positive association between the frequency of felt earthquakes and healthcare encounters for stress disorders. For every additional five felt earthquakes in the preceding six months, there was an increased odds of a healthcare encounter for stress disorder, after adjusting for age and sex. The study did not observe an association between the frequency of felt earthquakes and combined anxiety disorders, adjustment reaction, anxiety dissociative and somatoform disorders, or physical symptoms of anxiety.

Table 3.5. Summary of epidemiological studies of the association between upstream oil and gas development and mental and behavioral health outcomes in the United States and Canada. Studies are categorized by state and then chronologically by publication year.

Author (Year)	Region	Primary hydro-carbon produced	Funder	Study design	Surrogate of exposure *(distance evaluated if specified)*	Sample size, study time frame, and outcome data source	Confounders and covariates considered	Main findings[1]
Aker et al. (2022)	North-eastern British Columbia Canada	Natural Gas	Canadian Institutes of Health Research	Retrospective cohort	UNGD activity metric – IDW sum of wells for 2.5, 5, 10 km (8,202, 16,404, 32,808 ft) buffers around each postal code centroid	6,278 mothers 2006–2016 Northern Health (healthcare provider in Northeastern British Columbia)	Tobacco use, second-hand smoke exposure during pregnancy, mother's age at delivery & postal code, prior adverse pregnancy outcomes, complications during pregnancy, number of previous pregnancy, number of previous pregnancies, still birth, singleton, multiple birth count for pregnancy, infant's birth date & biological sex assigned at birth, gestational age at delivery, Apgar scores (1, 5 and 10 min), birthweight, head circumference	**IDW well density/proximity (2.5 km, 8,202 ft)** Depression (2nd quartile) ⬄ Anxiety ⬄ Substance Use ⬄ **IDW well density/proximity (5 km, 16,404 ft)** Depression (2nd and 3rd quartile) ▲ Anxiety ⬄ Substance Use ⬄ **IDW well density/proximity (10 km, 32,808 ft)** Depression (2nd and 3rd quartile) △ Anxiety ⬄ Substance Use ⬄
Casey et al. (2018a)	OK Statewide	Oil & natural gas	NIEHS	Time-series analysis using Google queries	Monthly counts of injection-induced earthquakes ≥ magnitude 4	Prevalence of searches for anxiety estimated for 75 weekly samples of the Google API 2010–2017 Oklahoma Google anxiety search data	US-wide anxiety search episodes, Oklahoma-specific health-related queries	**Google search episodes related to anxiety**: For each additional injection-induced earthquake ≥magnitude 4 that exceeded the monthly average, the proportion of Google search episodes increased by 1.3% (95% CI: 0.1-2.4%) In months with two or more ≥magnitude 4 injection-induced earthquakes, Google searched episodes focused on anxiety increased by 5.8% (95% CI, 2.3-9.3%).

Author (Year)	Region	Primary hydro-carbon produced	Funder	Study design	Surrogate of exposure *(distance evaluated if specified)*	Sample size, study time frame, and outcome data source	Confounders and covariates considered	Main findings[1]
Elser et al. (2023)	Oklahoma	Oil & natural gas	Stanford Research Computing Center	Retrospective cohort with repeated measures	County-level 6-month rolling average exposure to earthquakes ≥magnitude 4 at county level (USGC Advanced National Seismic System)	4,594 patients ≥ 18 years of age residing in OK during study period 2010-2019 Healthcare encounters for anxiety disorders, Optum Clinformatics Data Mart (commercia)l and Medicare Advantage Claims Databases	Age, sex, calendar year and month.	**For every additional five ≥magnitude 4 earthquakes in the preceding 6 months:** Healthcare visits for stress disorders ▲ Adjustment reaction ⬄ Anxiety-related disorders ⬄ Physical symptoms of anxiety ⬄
Casey et al. (2018b)	Marcellus Shale, PA	Natural gas	NIH, Degenstein Foundation	Case-control	UNGD activity metric – IDW[2] from participant residence, incorporating phase and duration of development (pad preparation, drilling, stimulation and production), total well depth and volume of natural gas produced	4,762 participants 2014–2015 Geisinger Health System electronic health records and questionnaire data	Race/ethnicity, sex, medical assistance, age, disordered sleep diagnosis or control date; smoking and alcohol use, BMI, antidepressant medication use in month prior to survey, community-based definition of place & socioeconomic deprivation, residential water source	**High UNGD exposure vs. very low** Mild depressive symptoms ▲ Moderate depression symptoms △ Moderately severe/severe depression symptoms △ Depression symptoms ▲ Disordered sleep ⬄
Casey et al. (2019)	Marcellus Shale, PA	Natural gas	NIEHS, National Institute on Drug Abuse, NIH Environmental Influences on Child Health Outcomes Program	Retrospective cohort	UNGD activity metric – IDW[2] between conception and the week prior to anxiety or depression (cases) based on well proximity to maternal residence, phase of development (pad development, drilling, hydraulic fracturing, production), total well depth, volume of natural gas produced	7,715 mothers and 8,371 births 2009–2013 Geisinger Health System	Maternal age at delivery, race/ethnicity, primary care provider status, smoking status during pregnancy, pre-pregnancy BMI, parity, receipt of antibiotic or Medical Assistance during pregnancy, income-based program surrogate for low family socioeconomic status, season/year of conception, gestational age, distance to nearest major road, community socioeconomic deprivation, mean residential greenness, residential well water use, decline in community-level housing value	**Highest UNGD exposure vs. lower UNGD exposure** Antenatal anxiety or depression ▲ Antenatal anxiety & depression (Both) ⬄ Adverse birth outcomes ⬄

Author (Year)	Region	Primary hydro-carbon produced	Funder	Study design	Surrogate of exposure *(distance evaluated if specified)*	Sample size, study time frame, and outcome data source	Confounders and covariates considered	Main findings[1]
Mayer & Olson Hazboun (2019)	United States	Oil & natural gas	Not disclosed	Ecological	County-level oil and gas production	18,306 records related to alcohol consumption prevalence 2002–2012 Dwyer-Lindgren et al. (2015)	County median income, average earnings per job, labor force participation, USDA Rural-Urban Codes, lagged O&G productions, year fixed effects, state fixed effects	**County-level oil production across US (per 100,000 barrels)** Males, heavy or binge drinking △ Females, heavy or binge drinking ▽ **County-level gas production across US (per 100 million cubic feet)** Males, heavy or binge drinking ⇔ Females, heavy or binge drinking ⇔

[1] Associations from studies that tested for statistical significance are represented using the following symbols: ▲=significant increase, ▼= significant decrease, ▽= non-significant decrease, △= non-significant increase, ⇔ = null findings/no association. Studies that did not test for statistical significance are noted in the table and results are briefly summarized. Unless explicitly stated, the summary of outcomes represents results from comparing the highest tertile/quantile/quartile/highest exposure category to the lowest exposure category. In other words, the increase or decrease in a health outcome is the highest exposure group compared to the lowest (or reference category).

Abbreviations: body mass index (BMI); inverse distanced weighted (IDW); National Institute of Environmental Health Sciences (NIEHS); National Institutes of Health (NIH); unconventional natural gas development (UNGD), United States Department of Agriculture (USDA).

3.3.2.5 Cancer

Five studies examined oil and gas development and cancer outcomes between 1990 and 2017 (**Table 3.6**). Three studies were conducted in Pennsylvania (Clark et al. 2022; Finkel, 2016; Fryzek et al., 2013), one in Colorado (McKenzie et al., 2017), one in Texas (Hoang et al. 2023) and none in California. Four out of five studies found statistically significant associations between upstream OGD and cancer.

Fryzek et al. (2013) evaluated incidence of childhood cancer before and after drilling occurred in Pennsylvania counties among individuals <20 years old using a county-level ecological design. In counties where wells were drilled, standardized incidence ratios (SIRs) for all childhood cancers and leukemia did not increase after drilling; however, a slightly elevated SIR was reported for central nervous system tumors after drilling, particularly in counties with a fewer number of wells (1–500 wells). No trends were observed by the number of wells drilled per county. This study noted the increase in wells drilled between 2003 and 2008 in Pennsylvania, but examined cancer incidence between 1990 and 2009. Therefore, the time frame assessed in this study does not allow for the evaluation of exposure to upstream OGD and cancer, given the longer latency expected between exposure and cancer development.

Finkel (2016) investigated unconventional natural gas development and cancer incidence in southwest Pennsylvania between 2000 and 2012 using an ecological county-level design. Urinary bladder cases were higher than expected in counties with shale gas activity. Thyroid cancer cases increased over time, regardless of unconventional gas development activity, and patterns for leukemia incidence were mixed. Overall, observed cancer incidence was higher than expected prior to unconventional gas development in counties, regardless of unconventional gas development activity. Both the Finkel and Fryzek studies are limited by county-level (rather than individual-level) evaluations of exposure to upstream OGD and county-level measures of cancer incidence and do not control for other confounding variables, including other environmental exposures, that may influence cancer development.

McKenzie et al. (2017) focused on the incidence of childhood cancer cases and their association with upstream OGD in Colorado using a registry-based case-control design. A linear increase in risk of acute lymphocytic leukemia (ALL) was observed with increasing proximity and density exposure categories (McKenzie et al., 2017). Using inverse distance weighted well counts within 16.1 km (10 miles) to estimate exposure, young individuals (ages 5–24) with ALL were 4.3 times as likely to live in the highest well proximity and density category as compared to those not diagnosed with ALL (McKenzie et al., 2017). Patients 5 to 24 years of age were included in this study to account for the approximate 10-year latency period between exposures before the age of 15 and the onset of cancer (McKenzie et al., 2017). Exposure to oil and gas-related compounds, including polycyclic aromatic hydrocarbons, other hydrocarbons such as benzene, and diesel exhaust, have all been linked to non-Hodgkin's lymphoma and ALL (Adgate et al., 2014; Kassotis et al., 2018; McKenzie et al., 2017). While no association was observed between proximity/density for young children (ages 0–4) with ALL, this may be due to the fact that not enough time has passed for the onset of cancer to occur, due to the 10-year latency period discussed previously (Adgate et al., 2014; Kassotis et al., 2018; McKenzie et al., 2017). No association was found for non-Hodgkin's lymphoma, regardless of age.

Clark et al. (2022) examined associations between residential proximity to OGD activity and risk of acute lymphoblastic leukemia (ALBL), the most common form of childhood leukemia, using a cancer registry-based case-control study (2009–2017). Cases were matched with controls based on birth year. Birth address was used to assign exposures using distance to nearest well and a water-specific metric of ID_{ups} which captures the inverse distance to the nearest upgradient OGD well. Two exposure windows were considered: (1) three months prior to conception to one year prior to diagnosis, called the "primary window," and (2) three months prior to conception to birth, called the "perinatal window." Children with at least one unconventional oil and gas well within 2 km (6,561 ft) of their birth residence during the primary window had higher odds of developing ALBL compared to those with no OGD wells. Children with at least one versus no UOG wells within 2 km (6,561 ft) during the perinatal window also had even higher odds of developing ALBL. These relationships were slightly attenuated after adjusting for maternal race and socio-economic status.

Hoang et al. (2023) performed a spatial clustering analysis of 4,305 brain tumors diagnosed in Texas between 2000–2007 in children aged ≤ 19 years. They identified 20 spatial clusters where the incidence of brain tumors was higher than expected, compared to the state-wide incidence rate. The second most significant cluster was in North Texas, included the Dallas-Fort Worth Metropolitan Area, and overlapped the Barnett Shale. The authors identified factors such as unaccounted population growth, natural gas production in the Barnett Shale, and the Dallas-Fort Worth airport as hypotheses that could contribute to this cluster. The third and fourth clusters, which were not statistically significant, were near ports where petroleum and petroleum products are imported and exported or near oil and gas refineries. The remaining 17 clusters, including the most significant cluster, did not appear to overlap with oil and gas basins.

Table 3.6. Summary of epidemiological studies on the association between upstream oil and gas development and cancer in the United States and Canada. Studies are categorized by state and then chronologically by publication year.

Author (Year)	Region	Primary hydro-carbon produced	Funder	Study design	Surrogate of exposure *(distance evaluated if specified)*	Sample size, study time frame, and outcome data source	Confounders and covariates considered	Main findings[1]
McKenzie et al. (2017)	Rural areas in CO; towns with population <50,000	Oil & natural gas	University of Colorado Cancer Center	Case-control (registry-based)	IDW well count for active wells within 16.1 km (52,821 ft) radius of residence	87 ALL cases 50 NHL cases 528 controls 2001–2013 Colorado Central Cancer Registry	Patient's age, race, gender, income, elevation, year of diagnosis	**Highest tertile compared to reference (0 wells within 16.1 km [52,821 ft])** **All ages:** Childhood ALL △ Childhood NHL ▽ **0 to 4 Years:** Childhood ALL ▽ Childhood NHL ⇔ **5 to 24 Years:** Childhood ALL ▲ Childhood NHL ⇔
Fryzek et al. (2013)	PA Statewide	Natural gas	America's Natural Gas Alliance	Ecological	County-level well counts before and after oil and gas wells (vertical, horizontal, Marcellus) spudded	1,874 cancer cases pre-drilling 1,996 cancer cases post-drilling 1990–2009 Pennsylvania Department of Health and United States Census Bureau	Standardized incidence ratios calculated and indirectly standardized for age and sex	**Childhood cancer standardized incidence ratios for counties after drilling vs. before horizontal drilling** **Total wells for all counties with wells after drilling** All childhood cancer △ Leukemia △ Central nervous system tumors ▲ **Total wells for all counties, 1990–2009** All childhood cancer ⇔ Leukemia ⇔ Central nervous system tumors ⇔

Author (Year)	Region	Primary hydro-carbon produced	Funder	Study design	Surrogate of exposure *(distance evaluated if specified)*	Sample size, study time frame, and outcome data source	Confounders and covariates considered	Main findings[1]
Finkel (2016)	Southwest PA	Natural gas	Not disclosed	Ecological	Categorized county-level well counts (high, moderate, minimal producing wells)	**All PA cancer cases** Urinary bladder - 57,177 Thyroid - 31,599 Leukemia - 27,670 2000–2012 Pennsylvania Department of Health Bureau of Health Statistics and Research's Pennsylvania Cancer Registry	Standardized incidence ratios calculated and indirectly standardized for age, sex, race	**% Difference 2008 - 2012 vs. 2000 - 2004, All PA, Males** Urinary bladder cancer – 10.00% Thyroid cancer – 91.20% Leukemia – 18.90% **SIR, Urinary bladder cancer, Males, All PA** 2000–2004 ▲ 2004–2008 ▲ 2008–2012 ▲ **SIR, Thyroid cancer, Males, All PA** 2000–2004 △ 2004–2008 ▲ 2008–2012 ▲ **SIR, Leukemia, Males, All PA** 2000–2004 ▽ 2004–2008 ▽ 2008–2012 ▼ **% Difference 2008–2012 vs. 2000–2004, All PA, Females** Urinary bladder cancer - 0.50% Thyroid cancer - 71.50% Leukemia - 18.30% **SIR, Urinary bladder cancer, Females, All PA** 2000–2004 ▲ 2004–2008 ▲ 2008–2012 ▲ **SIR, Thyroid cancer, Females, All PA** 2000–2004 ▲ 2004–2008 ▲ 2008–2012 ▲ **SIR, Leukemia, Females, All PA** 2000–2004 ▼ 2004–2008 ▼ 2008–2012 ▽

Author (Year)	Region	Primary hydro-carbon produced	Funder	Study design	Surrogate of exposure *(distance evaluated if specified)*	Sample size, study time frame, and outcome data source	Confounders and covariates considered	Main findings[1]
Clark et al. (2022)	Pennsylvania	Unconventional oil & gas	NIH, EPA	case-control	IDW[2] index within 2 km, 5 km, and 10 km (6,561, 16,404, and 32,808 ft) for active UOG wells (used as binary); IDups: the inverse distance to the nearest upgradient active UOG well	2002–2017 Cases: 405, Controls: 2,080 Pennsylvania Department of Health	sex, mode of delivery, birth weight, race, ethnicity, maternal education, air pollution exposure, and pesticide exposure	**Risk of childhood acute lymphoblastic leukemia (parsimonious model)** **Primary exposure window:** 2 km (6,561 ft) △ 5 km (16,404 ft) △ 10 km (32,808 ft) ⬄ **Perinatal exposure window:** 2 km (6,561 ft) △ 5 km (16,404 ft) △ 10 km (32,808 ft) △
Hoang et al. 2023	Texas	Oil and natural gas	No external funding	Spatial cluster analysis of census tracts	None	4,305 brain tumors diagnosed in children ≤19 years old 2000–2017 Texas Cancer Registry	Age	Relative risk of childhood brain tumors for 20 clusters across Texas, two of which were found to significantly increase risk (significant clusters: Texas Medical Center; large portion of North Texas)

[1] Associations from studies that tested for statistical significance are represented using the following symbols: ▲=significant increase, ▼= significant decrease, ▽= non-significant decrease, △= non-significant increase, ⬄ = null findings/no association. Studies that did not test for statistical significance are noted in the table and results are briefly summarized. Unless explicitly stated, the summary of outcomes represents results from comparing the highest tertile/quantile/quartile/highest exposure category to the lowest exposure category. In other words, the increase or decrease in a health outcome is the highest exposure group compared to the lowest (or reference category).

Abbreviations: acute lymphocytic leukemia (ALL), inverse distance weighted (IDW), non-Hodgkin lymphoma (NHL), standardized incidence ratio (SIR).

3.3.2.6 Cardiovascular outcomes

Five studies evaluated associations between cardiovascular outcomes, including markers of cardiovascular disease, heart failure hospitalizations, acute myocardial infarction hospitalizations and mortality, and stroke mortality (Denham et al., 2021; Hu et al., 2022; McKenzie et al., 2019b; McAlexander et al., 2020; Trickey et al., 2023; **Table 3.7**) and upstream OGD. These studies examined upstream OGD exposures and outcomes between 2005 and 2018. None were conducted in California.

In a study focused in northeastern Colorado's Denver-Julesburg Basin, McKenzie et al. (2019b) found that well intensity per square kilometer was associated with indicators of cardiovascular disease, including increased indications of systemic inflammation, arterial stiffness, and systolic blood pressure among those not taking prescription medications. While specific mechanisms (e.g., air pollution, noise, stress) are not evaluated in this study, inhalation of hydrocarbons has been associated with increases in cardiovascular emergency visits (Ye et al., 2017) and cardiovascular morbidity and mortality (Bard et al., 2014; Harrison, 2016; Villeneuve et al., 2013; Xu et al., 2009).

Two recently published studies evaluated cardiovascular outcomes in Pennsylvania. McAlexander et al. (2020) examined heart failure among residents living near unconventional natural gas development, with exposure defined as residential proximity to wells, nearby well density, well depth, natural gas production, and phase of activity at the well pad 30 days prior to hospitalization. A statistically significant increase in heart failure hospitalization was observed among those in the highest exposure category compared to the lowest exposure category during pad preparation, stimulation and production. Associations were more pronounced among those with more severe heart failure at baseline, indicating that those with heart failure may be more vulnerable to adverse health impacts associated with unconventional natural gas development. Denham et al. (2021) also found significant associations between acute myocardial infarction hospitalization and mortality rates and county-level contemporaneous drilled wells, overall well count, and well density.

Trickey et al. (2023) used a difference-in-differences study design (that controls for time-invariant confounders by design since a place is compared to itself over time) to evaluate the impact of upstream OGD on cardiovascular and respiratory disease hospitalizations among Medicare enrollees from 2009–2015 in three Northern Pennsylvania counties. The study used daily hospitalization data from the 100% sample of Medicare fee-for-service beneficiaries in Northern Pennsylvania (n=36 zip codes) and Southern New York (n=128 zip codes). They defined exposure at the ZIP code annual level based on presence of OGD activity. No New York zip codes were exposed due to a drilling moratorium. In the primary analysis, they used 60 New York zip codes (not bordering Pennsylvania but nearby) as the unexposed group. Outcomes included: acute myocardial infarction, chronic obstructive pulmonary disease (COPD) and bronchiectasis, stroke, heart failure, and ischemic heart disease. Results showed that OGD was associated with more cardiovascular disease-related hospitalizations than expected in 2012–2015. For example, in 2015, exposed zip codes had 8.8 more heart failure hospitalizations per 1000 Medicare enrollees than expected associated with ODG activity.

Hu et al. (2022) used state-level data from the U.S. Centers for Disease Control and Prevention from 2010–2018 on stroke mortality (rate per 100,000) among adults aged 65+ years. They defined states as “fracking” and “non-fracking” states based on the presence of any hydraulically fractured wells. This resulted in 24 fracking states (n=19 active, n=5 not active) and 25 non-fracking states included in the analysis (Alaska was excluded). In geographical and temporal weighted regression adjusted for state-level behavioral, socioeconomic, and health risk factors, results revealed a correlation between fracking annualized loss expectancy and stroke mortality, with a potentially stronger correlation for men. This ecologic study is especially prone exposure misclassification that could lead to spurious associations.

Table 3.7. Summary of epidemiological studies that evaluate upstream oil and gas development and cardiovascular outcomes in the United States and Canada. Studies are categorized by state and then chronologically by publication year.

Author (Year)	Region	Primary hydro-carbon produced	Funder	Study design	Surrogate of exposure *(distance evaluated if specified)*	Sample size, study time frame, and outcome data source	Confounders and covariates considered	Main findings[1]
McKenzie et al. (2019b)	Northeast CO	Oil & natural gas	NIEHS, NSF	Cross-sectional	IA-IDW (well intensity/km²) within 16 km (52,493 ft) of residence	97 adults 2015–2016 Clinic visits which included questionnaire, measurements, and blood sampling	Age, sex, race/ethnicity, BMI, education, income, employment status	Augmentation index ▲ Systolic blood pressure △ Diastolic blood pressure △ IL-1β/IL-6/IL-8 ⇔ TNF-α △ **No prescription medications:** Systolic blood pressure ▲ Diastolic blood pressure △
McAlexander et al. (2020)	PA Statewide	Natural gas	NIEHS	Case-control	UNGD activity metric – IDW² incorporating well depth, total daily volume of natural gas production, & phase (pad preparation, drilling, stimulation, and production) 30 days prior to hospitalization or matched control date	9,054 patients with heart failure 5,839 hospitalizations 3,215 controls 2008–2015 Geisinger Health System	Sex, race/ethnicity, age, smoking status, Charlson index of morbidity, receipt of medical assistance, comorbid conditions, duration of care, medication use, BMI, region, community socioeconomic deprivation, proximity to nearest major & minor roadway, normalized difference vegetation index	**Hospitalizations of heart failure patients (fully adjusted Model 5):** Pad preparation ▲ Drilling ⇔ Stimulation ▲ Production▲

Author (Year)	Region	Primary hydro-carbon produced	Funder	Study design	Surrogate of exposure *(distance evaluated if specified)*	Sample size, study time frame, and outcome data source	Confounders and covariates considered	Main findings[1]
Denham et al. (2021)	Marcellus (PA & NY)	Natural gas	NIH	Ecologic al	County-level variables - drilled wells (quarter-year); well county and well density (wells/mi^2)	2,840 county-year-quarters 2005–2014 Pennsylvania Health Care Cost Containment Council and New York's Statewide Planning and Research Cooperative System and United States' National Center for Health Statistics	Adjusted for age, sex, racial/ethnic composition of age-sex group, county-level unemployment rate, poverty rate, median household income, total number of hospitals, uninsured rates	**Cumulative well counts & acute myocardial infarction (AMI) hospitalizations per 10,000 residents** **Males** 45–54 years old ▲ 55–64 years old △ 65–74 years old ▲ 75+ years old △ **Females** 45–54 years old ⬄ 55–64 years old △ 65–74 years old ▲ 75+ years old ▲ **Well counts & AMI mortality/10,000 residents** **Males** 45–54 years old ▲ 55–64 years old △ 65–74 years old ▽ 75+ years old ⬄ **Females** 45–54 years old ▽ 55–64 years old ▽ 65–74 years old ⬄ 75+ years old △ **Well density & AMI hospitalizations/10,000 residents** **Males** 45–54 years old ▲ 55–64 years old △ 65–74 years old △ 75+ years old △ **Females** 45–54 years old ⬄ 55–64 years old ⬄ 65–74 years old △ 75+ years old ▲ **Well density & AMI mortality/10,000 residents** **Males** 45–54 years old ▲ 55–64 years old ⬄ 65–74 years old ▽ 75+ years old △ **Females** 45–54 years old ⬄ 55–64 years old ▽ 65–74 years old △ 75+ years old △

Author (Year)	Region	Primary hydro-carbon produced	Funder	Study design	Surrogate of exposure *(distance evaluated if specified)*	Sample size, study time frame, and outcome data source	Confounders and covariates considered	Main findings[1]
Hu et al. (2022)	49 US states (excludes Alaska)	Fracking wells	None	Ecologic al	Any fracking within a state	2010–2018 Stroke mortality in 65+ CDC	Prevalence of diabetes, cardiovascular, overdose, tobacco use, high cholesterol, physical activity, mean income, marital rate, employment rate, alcohol consumption, education, concentrations of hazardous air pollutants	Positive spatiotemporal correlation between fracking annualized loss expectancy and stroke mortality, with a potentially stronger correlation for men.
Trickey et al. (2023)	Three Northern Pennsylva nia Counties and eight New York Counties	Unconvent ional oil & gas	Universi ty of Chicago and Argonn e National Laborat ories	Differenc e-in-differenc es	UOG activity in zip code (binary variable)	61,152 Medicare enrollees in 2015 2002–2015 Hospitalisation data (MedPAR) of 100% of Medicare fee-for-service beneficiaries	None. Modeling method controls for time-invariant confounders by design.	**Any diagnosis of COPD & bronchiectasis (hospitalizations):** 2010 ⇔ 2011 ⇔ 2012 ▲ 2013 ▲ 2014 ▲ 2015 ⇔ **Heart failure:** 2010 ⇔ 2011 ⇔ 2012 ▲ 2013 ▲ 2014 ▲ 2015 ▲ **AMI:** 2010 ⇔ 2011 ⇔ 2012 ▲ 2013 ▲ 2014 ▲ 2015 ▲ **Ischaemic heart disease (including AMI):** 2010 ⇔ 2011 ▲ 2012 ▲ 2013 ▲ 2014 ▲ 2015 ▲ **Stroke:** 2010 ⇔ 2011 ⇔ 2012 ⇔ 2013 ⇔ 2014 ⇔ 2015 ⇔

[1] Associations from studies that tested for statistical significance are represented using the following symbols: ▲=significant increase, ▼= significant decrease, ▽= non-significant decrease, △= non-significant increase, ⇔ = null findings/no association. Studies that did not test for statistical significance are noted in the table and results are briefly summarized. Unless explicitly stated, the summary of outcomes represents results from comparing the highest tertile/quantile/quartile/highest exposure category to the lowest exposure category. In other words, the increase or decrease in a health outcome is the highest exposure group compared to the lowest (or reference category).

Abbreviations: acute myocardial infarction (AMI); body mass index (BMI); intensity adjusted inverse distance weighted well intensity (IA-IDW); interleukin (IL); National Institute of Environmental Health Sciences (NIEHS); National Institutes of Health (NIH); National Science Foundation (NSF); tumor necrosis factor alpha (TNF- α); unconventional natural gas development (UNGD).

3.3.2.7 *Other adverse health outcomes*

Fifteen studies examined upstream OGD and other health outcomes, including all-cause mortality, non-outcome specific hospitalizations, antineutrophil cytoplasmic antibody (ANCA)-associated vasculitis, migraine headaches, and self-reported symptoms and outcomes.[10] These studies are summarized below by outcome and are shown in **Table 3.8**. A single study, on migraine headache, was conducted in California related to other adverse health outcomes.

Migraine headache

Elser et al. (2021) conducted a case-control study of migraineurs and those without migraine among Sutter Health patients across 27 counties in Northern California between 2014 and 2018. The authors also assessed the relationship of environmental factors with migraine severity in a case-only analysis. The authors evaluated exposure to four environmental stressors, including ambient annual average concentrations of $PM_{2.5}$ and NO_2 at the U.S. Census block group level and inverse-distance weighted metrics (considering proximity and nearby density) of methane super-emitters (including but not limited to oil and gas sources), as well as active oil and gas wells. Exposure to methane super-emitters and ambient NO_2 were associated with increased odds of being a migraine case. The authors did not observe an association between exposure to active oil and gas wells and migraine prevalence or severity.

All-cause mortality

Three studies evaluated the association between upstream OGD and all-cause mortality in the United States (Boslett & Hill, 2022; Li et al., 2022; Mayer et al., 2019). Using two methods — a Cox proportional hazards model and a difference-in-differences design — the Li et al. (2022) zip code level analysis found a statistically significant increased risk of mortality associated with Medicare beneficiaries living in proximity to and downwind of unconventional oil and gas wells. Similarly, another study using ecological study design found that for all counties in the United States, morality rates increase as the number of oil and gas wells increases (within-effect, active oil and gas wells) (Mayer et al., 2019). However, the authors also found that counties with active oil and gas production tend to have lower all-age, all-cause mortality rates (between-effect, average wells) compared to counties without oil and gas production. When evaluated at the regional level, these findings persist only for the southern United States, suggesting that regional differences in upstream OGD may influence all-cause, all-age mortality (Mayer et al., 2019).

Boslett and Hill (2022) applied an ecological retrospective study design using the National Vital Statistics System Multiple Cause of Death Data at the county level (1999–2016) to assess the relationship between boom-and-bust cycles associated with coal, oil, and natural gas extraction and mortality. Two-way fixed effects models controlling for state and year found no association between drilled horizontal wells and mortality.

[10] One study included in this count, Johnston et al. (2021), evaluates both measured respiratory outcomes and self-reported symptoms. This study is described in detail above under Section 3.3.2.3 “Respiratory outcomes” and also discussed within this section under “Self-reported symptoms.”

Non-outcome specific hospitalizations

Two ecological studies examined the association between upstream OGD and a variety of non-outcome-specific, broad-disease categories of hospitalization rates in Pennsylvania between 2003 and 2014 (Denham et al., 2019; Jemielita et al., 2015). Denham et al. (2019) examined the relationship of 16 broad-disease categories of hospitalization rates[11] and total hospitalizations, with three county-specific exposure metrics at the county-year level: cumulative well count, cumulative well density (per square kilometer), and contemporaneous spudded wells. For all exposure metrics, the authors found significant positive associations with hospitalizations for genitourinary diseases. At a county level, an increase of 0.008 hospitalizations for genitourinary diseases per 10,000 residents was associated with the addition of one cumulative oil and gas well, and a 1.2% relative increase in the genitourinary hospitalization rate was associated with the addition of 100 cumulative oil and gas wells as compared with the baseline average rate. Twenty hospitalizations for genitourinary diseases per 10,000 residents were associated with an increase of one well per square kilometer (0.39 square miles). After removing large metropolitan counties, genitourinary hospitalizations were significantly positive associated with well count and well density remained. The authors also observed an increase of 0.004 skin-related hospitalizations per 10,000 residents with each additional well and well count and well density, and an increase of 12.2 hospitalizations for skin-related diseases per 10,000 residents was associated with each additional well per square kilometer (0.39 square miles), compared to the baseline rates. Finally, they found that cumulative well count and well density had significant positive associations with genitourinary and skin-related hospitalizations after controlling for multiple comparisons. Genitourinary hospitalization findings were driven by non-elderly adult females (ages 20–64) and included kidney infections, calculus of the ureter, and urinary tract infections, whereas the skin-related hospitalization findings were driven by non-elderly adult males. They found negative associations with infectious diseases and musculoskeletal diseases and no associations with other hospitalization categories or overall hospitalizations. No associations were found with any type of hospitalizations and contemporaneous wells.

Jemielita et al. (2015) examined ZIP code-specific inpatient prevalence rates per year per 100 people for the top 25 specific medical categories[12] and total inpatient rates, and their relationship to both the number of oil and gas wells (within a specific ZIP code for a specific year) and density of oil and gas wells (wells per square kilometer at the ZIP code level). With the strictest criteria to account for multiple comparisons, only cardiology inpatient rates were significantly associated

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[11] Denham et al. (2019). The 16 broad-disease categories of hospitalization rates examined were infectious diseases, neoplasms, endocrine/nutritional & metabolic diseases/immunity disorders, diseases of the blood and blood-forming organs, mental disorders, diseases of the nervous system and sense organs, diseases of the circulatory system, diseases of the respiratory system, diseases of the digestive system, diseases of genitourinary system, complications of pregnancy and childbirth, diseases of the skin and subcutaneous tissues, diseases of the musculoskeletal system and connective tissue, congenital abnormalities, conditions originating in the perinatal period, injury and poisoning.

[12] Jemielita et al. (2015). The 25 specific medical categories of inpatient rates examined were cardiology, dermatology, endocrine, gastroenterology, general medicine, general surgery, gynecology, hematology, neonatology, nephrology, neurology, normal newborns, ob/delivery, oncology, ophthalmology, orthopedics, other/ob, otolaryngology, psych/drug abuse, pulmonary, rheumatology, thoracic surgery, trauma, urology, and vascular surgery.

with both number of wells and well density, and neurology inpatient rates were significantly associated with well density. However, the authors found the following inpatient prevalence rates were positively associated with ZIP code-level well counts and well density: dermatology, neonatology, neurology, oncology, and urology. Jemielita et al. (2015) also reported positive associations between well density and dermatology, endocrine, neurology, oncology, urology, and overall inpatient prevalence rates. The remaining inpatient prevalence rates had no associations with the two exposure measures. The authors also performed well density quantile analyses and found significant positive associations with inpatient prevalence rates for cardiology and neurology. Positive associations (though non-significant) were seen again with dermatology, neurology, oncology, and urology inpatient prevalence rates.

Antineutrophil cytoplasmic antibody (ANCA)-associated vasculitis

One ecological study evaluated the impacts of natural gas drilling in West Virginia on ANCA-associated vasculitis diagnoses and their subtypes (myeloperoxidase [MPO]-ANCA and persistent proteinase 3 [PR3]-ANCA) between 1990 and 2019 (Makati et al., 2022). The authors found the proportion of MPO-ANCA-diagnosed patients significantly increased after 2010, from 37.5% in 2010 to 61% after 2010. During this time, unconventional natural gas development rose more than tenfold after 2010. Similarly, the prevalence of ANCA-associated vasculitis diagnoses also increased significantly after 2010 — from 64.8 to 141.9 cases per one million individuals (Makati et al., 2022). This increase was largely driven by a rise in MPO-ANCA cases.

Self-reported symptoms

Ten studies focused on self-reported health symptoms related to exposure to upstream OGD, six of which were conducted in Pennsylvania (Blinn et al., 2020; Ferrar et al., 2013; Rabinowitz et al., 2015; Saberi et al., 2014; Steinzor et al., 2013; Tustin et al., 2016; Weinberger et al., 2017), one in Colorado (Weisner et al., 2023), one in Ohio (Elliot et al., 2018) and one in California (Johnston et al., 2021). Three of these studies relied on convenience sampling to recruit study participants, a well-known limitation of studies that rely on self-reported information to assess potential harmful exposures due to the small sample size (n=33–108) and potential for selection bias (Ferrar et al., 2013; Saberi et al., 2014; Steinzor et al., 2013). Of note, other studies evaluated health symptoms and outcomes using other methods, such as structured health assessments with physician review (Weinberger et al., 2017) or standardized and validated questionnaires (Tustin et al., 2016).

Self-report studies have consistently documented skin irritation and rash; respiratory symptoms including difficulty breathing; nose, throat, and sinus problems; gastrointestinal disturbances; headache; sleep disruption; and psychological symptoms including stress as symptoms related to oil and gas development (Ferrar et al., 2013; Rabinowitz et al., 2015; Saberi, 2013; Steinzor et al., 2013). Rabinowitz et al. (2015) found increased prevalence of dermal and respiratory symptoms was associated with increased proximity to gas wells.

Johnston et al. (2021) evaluated a variety of acute health symptoms in South Los Angeles and found that residents living near active oil wells self-reported higher odds of recent wheeze, sore throat, chest tightness, eye and nose irritation, dizziness, and ringing of the ears as compared to residents living near idle wells. Seven additional studies that rely on self-reported health symptom data between 2010 and 2017 have also reported the same acute health symptoms among residents living in areas of oil and gas development in Ohio and Pennsylvania (Blinn et al., 2020;

Elliott et al., 2018; Ferrar et al., 2013; Rabinowitz et al., 2015; Steinzor et al., 2013; Weinberger et al., 2017).

Blinn et al. (2020) found that exposure to unconventional OGD — estimated by proximity to and/or density of nearby wells — was associated with headache, difficulty sleeping, sore throat, stress, and itchy or burning eyes. Annual emissions concentrations (AEC) examined near unconventional OGD were also significantly associated with numerous health outcomes; the top five most reported symptoms being difficulty sleeping, anxiety/worry, cough, stress, and shortness of breath (difficulty breathing) (Blinn et al., 2020). Similarly, Rabinowitz et al. (2015) found that living within 1 km (3,281 ft) of active natural gas drilling is significantly associated with increased dermal symptoms. Gastrointestinal and neurological symptoms also increased among residents living within 1 km (3,281 ft) of active drilling, although these results were not significant (Blinn et al., 2020). Tustin et al. (2016) found the highest quartile of unconventional natural gas development activity, compared with the lowest, was associated with significantly increased odds of the following combinations of two or more outcomes: chronic rhinosinusitis and higher levels of fatigue (88% increased odds), migraine headache and higher levels of fatigue (95% increased odds), and all three outcomes (84% increased odds). Weinberger et al. (2017) found physician-reviewed symptoms reported within 1 km (3,281 ft) of active well drilling included sleep disruption, headache, throat irritation, stress or anxiety, cough, shortness of breath, sinus problems, fatigue, nausea, and wheezing; although, these findings were not statistically significant.

Elliott et al. (2018) sampled the drinking water of 66 Ohio homes located at varying distances from upstream OGD and found oil and gas-associated pollutants to be present in both the groundwater and surface water near oil and gas sites. The authors detected significantly elevated levels of toluene in groundwater and halogenated compounds in surface water. Furthermore, the authors found that as distance to the nearest well increased, the odds of detecting trihalomethanes, bromoform, and dibromochloromethane in surface water significantly decreased (odds ratios: 0.28–0.29 per km).[13] Similarly, the odds of detecting gasoline range organics, toluene, and organic compounds in groundwater also decrease as distance to the nearest oil and gas well increases. These findings were statistically significant, with the exception of organic compound detection. The authors accompanied the water sampling campaign with a self-report survey and found that "those with higher inverse-distance-squared-weighted unconventional oil and gas well counts within 5 km (16,404 ft) around the home were more likely to report experiencing general health symptoms (e.g., stress, fatigue)" (Elliott et al., 2018).

Weisner et al. (2023) undertook a cross-sectional survey study of 427 adults and 59 children to evaluate associations between self-reported health symptoms (Summed Likert scores for upper respiratory, lower respiratory, mental health, neurological, gastrointestinal, or acute symptoms) and residential distance from multi-well oil and gas sites in Broomfield, Colorado, in 2021. After adjustment for several covariates, respondents living within 1 mile (1.6 km) of a multi-well oil and gas site tended to report higher frequencies of upper respiratory, lower respiratory, gastrointestinal, and acute symptoms than respondents living more than 2 miles (3.2 km) from the sites, with the largest differences for upper respiratory and acute symptoms (nausea, vomiting, nosebleeds, lung irritation, shortness of breath, cough, and throat irritation).

[13] This incremental increase in odds ratios is applicable to bromoform, and dibromochloromethane in surface water.

Table 3.8. Summary of epidemiological studies that evaluate upstream oil and gas development and other adverse health outcomes in the United States and Canada. Studies are categorized by health outcome, by state and then chronologically by publication year.

Author (Year)	Health outcome category	Region	Primary hydro-carbon produced	Funder	Study design	Surrogate of exposure *(distance evaluated if specified)*	Sample size, study time frame, and outcome data source	Confounders and covariates considered	Main findings[1]
Mayer (2019)	All-cause mortality	Rural places, United States	Oil & natural gas	Not disclosed	Ecological	County-level number of active oil and gas wells and county-level averages for active oil and gas wells, aggregated nationally and regionally	47,937 deaths 2000–2016 Center for Disease Control	Labor force participation ratio, % poverty, median income, per capita income	*p-values of <0.05*, <0.01**, <0.001*** reported below; authors define statistical significance as p-value <0.01*** **All-cause mortality, All Ages** *Active oil and gas wells* All U.S. ▲ *** South △ * *Average oil and gas wells* All U.S. ▼ *** South ▼ ** Northeast △* **All-cause mortality, Females, 15–64** *Active oil and gas wells* South ▼ ** West △ * *Average oil and gas wells* Northeast △ * **All-cause mortality, Males, 15–64** *Active oil and gas wells* *South* ▽*
Li et al. (2022)	All-cause mortality	United States	Unconven-tional oil & gas	US EPA, NIH, Climate Change Solutions Fund - Harvard University	Retrospective cohort & differences in differences	Zip code-level proximity exposure to unconventional oil and gas wells; sub-analysis of downwind vs. upwind exposure	15,198,496 Medicare beneficiaries 2001–2015 US Energy Information Administration, Center for Medicare & Medicaid Service	Sex, Medicaid availability, age, race/ethnicity, $PM_{2.5}$ ($\mu g/m^3$), development ratio, population density, income, educational attainment, BMI, smoking status, proximity-exposure to conventional oil and gas development	**Low proximity exposure vs. unexposed** All-cause mortality ▲ Mortality (upwind) ▲ Mortality (downwind) ⇔ **Medium & high proximity exposure vs. unexposed** All-cause mortality ▲ Mortality (upwind) ▲ Mortality (downwind) ▲

Author (Year)	Health outcome category	Region	Primary hydro-carbon produced	Funder	Study design	Surrogate of exposure *(distance evaluated if specified)*	Sample size, study time frame, and outcome data source	Confounders and covariates considered	Main findings[1]
Boslett & Hill (2022)	All-cause mortality	United States	Unconven-tional oil & gas	NIH	Ecological	Number of newly drilled horizontal oil & gas wells per county per year	1999–2016 CDC National Vital Statistics System (NVSS) Multiple Cause of Death Data	Year, shares of the county population who are white, Hispanic, and working-aged (25–64 years old); total population; and the total number of hospitals and pharmacies in the county	**# of horizontal O&G wells (in 100s), 0 < X ≤25 miles (40 km):** Non-drug mortality ⇔ Working age non-drug mortality △ Drug overdose mortality ⇔ Opioid overdose mortality ⇔ Non-drug overdose suicides ⇔ Alcohol overdoses ⇔ **# of horizontal O&G wells (in 100s), 25 <X ≤50 miles (40 km <X ≤80 km) :** Non-drug mortality ▼ Working age non-drug mortality ▽ Drug overdose mortality ▼ Opioid overdose mortality ▼ Non-drug overdose suicides ⇔ Alcohol overdoses ⇔ **# of horizontal O&G wells (in 100s):** Non-drug mortality ⇔ Working age non-drug mortality ⇔ Drug overdose mortality ⇔ Opioid overdose mortality ⇔ Non-drug overdose suicides ▲ Alcohol overdoses ⇔
Jemielita et al. (2015)	Non-outcome specific hospitalizations	Bradford, Susquehanna and Wayne County, PA	Oil & natural gas	NIEHS	Ecological	Wells per zip code per year (well analysis) and wells density per square kilometer per year (quantile analysis)	92,805 hospitalizations in 67 zip codes 2007–2011 Pennsylvania Health Care Cost Containment Council	Not considered	**Wells per zip code per year, inpatient prevalence rates:** Cardiology ▲ Dermatology, neonatology, neurology, oncology, urology △ **Well density per year, inpatient prevalence rates:** Cardiology ▲ Neurology ▲ Dermatology, endocrine, neurology, oncology, urology △

Author (Year)	Health outcome category	Region	Primary hydro-carbon produced	Funder	Study design	Surrogate of exposure *(distance evaluated if specified)*	Sample size, study time frame, and outcome data source	Confounders and covariates considered	Main findings[1]
Denham et al. (2019)	Non-outcome specific hospitalizations	54 rural counties that are not large metro areas, PA	Natural gas	NIH	Ecological	County-level wells for each year, cumulative well count and cumulative well density per square kilometer	1,452 records 2003–2014 Pennsylvania Health Care Cost Containment Council	Annual county-level data, including distributions of age, sex, race-ethnicity, poverty and median income, unemployment rates, hospital counts, uninsured rates	**Increased well density:** All-cause hospitalizations ⇔ Infectious diseases ▽ Neoplasms △ Endocrine/immune ⇔ Blood ⇔ Nervous system ⇔ Circulatory ⇔ Respiratory ⇔ Digestive ⇔ Genitourinary ▲ Pregnancy ⇔ Skin ▲ Musculoskeletal ⇔ CM ⇔ Perinatal ⇔
Makati et al. (2022)	ANCA-associated vasculitis	Northcentral, WV	Unconven-tional natural gas	None	Retrospective cohort	County-level unconventional natural gas production per year - pre-2010 vs. post-2010	212 patients diagnosed with ANCA-associated vasculitis 1990–2019 West Virginia University Health System-affiliated hospitals health records	Age, sex	**Natural gas production before 2010 vs. after 2010** ANCA-associated vasculitis ▲ PR3-ANCA (subtype) ⇔ MPO-ANCA (subtype) ▲
Elser et al. (2021)	Migraines	Northern CA	Oil & gas	CARB, NIEHS	Case-control (Case-case analysis for migraine severity)	Annual average concentrations of $PM_{2.5}$ and NO_2 at the block group level. Methane super-emitters (IDW sum kg/hour of all methane sources within 10 km (32,808 ft) of residence, weighted IDW^2. IDW sum of active oil and gas wells within 10 km (32,808 ft) of each residence and presence of any active oil or gas well within 10 km (32,808 ft).	360,139 patients 89,575 cases 270,564 controls 2014–2018 Sutter Health Electronic Health Records	Age, sex, race/ethnicity, Medicaid use, number of primary care visits per year, block group-level population density, poverty	**IDW Active O&G well (per 1,000-unit increase)** Migraine case ⇔ MPA score ⇔ Urgent care visit ⇔ Neurology visit ⇔ Triptans ⇔ ED visit ⇔

Author (Year)	Health outcome category	Region	Primary hydro-carbon produced	Funder	Study design	Surrogate of exposure *(distance evaluated if specified)*	Sample size, study time frame, and outcome data source	Confounders and covariates considered	Main findings[1]
Weisner et al. (2023)	Self-reported symptoms	Colorado: City and County of Broomfield	UOGD	City and County of Broomfield	Cross-sectional	Residential proximity to UOGD (within 1 mile (1.6 km) versus >2 miles (3.2 km)	n=3393 2020–2021 survey	Age, sex, race, smoking, alcohol consumption, time spent in home, number of children <18 years in home, exercise, number of chronic health conditions, time of residence at current home, education level and occupation.	**Difference between >2 Mile (3.2 km) and 1–2 Mile (1.6–3.2 km) Means to multiwell O&G site:** Total symptoms ⇔ Upper respiratory ⇔ Lower respiratory ⇔ Mental Health ⇔ Neurological ⇔ Gastrointestinal ⇔ Acute ⇔ **Difference between >2 Mile (3.2 km) and <1 Mile (1.6 km) Means to multiwell O&G site:** Total symptoms ▲ Upper respiratory △ Lower respiratory ▲ Mental Health ⇔ Neurological ⇔ Gastrointestinal ▲ Acute ▲
Johnston et al. (2021)	Respir-atory & self-reported acute health symptoms	South Los Angeles, CA North University Park & Jefferson Park	Oil	NIEHS	Cross-sectional (self-reported survey with lung function measurements)	1 km (3,281 ft) buffer around two oil development sites, one with 28 active wells (Jefferson Park) and one with 21 idle wells (North University Park)	960 residents from 488 addresses 747 valid spirometry tests 2017–2019 Self-reported symptoms & spirometry measurements	Age, sex, height, age-height interaction, race/ethnicity, weight, recent flu/cold, proximity to freeway, asthma status smoking status, indoor exposure to environmental tobacco smoke, season, wind direction (downwind vs. upwind)	**Self-reported acute health symptoms** **Active vs. idle well site** Recent wheeze ▲ Recent cough every morning ▽ Sleep disturbed by wheeze △ Sore throat ▲ Chest tightness ▲ Sneezing/runny nose △ Eye irritation ▲ Nose irritation ▲ Dizziness ▲ Headache △ Fatigue △ Ringing of the ears ▲ Diarrhea ▽ Nausea/vomiting ▽ Nosebleeds △ Backache △ Rash ▽ *Lung function findings shown in* **Table 3.4**.

Author (Year)	Health outcome category	Region	Primary hydro-carbon produced	Funder	Study design	Surrogate of exposure *(distance evaluated if specified)*	Sample size, study time frame, and outcome data source	Confounders and covariates considered	Main findings[1]
Elliot et al. (2018)	Other / General health outcomes	Ohio, Appala-chian Basin, Belmont County	Unconventional oil & gas	Yale Institute of Biospheric Studies, Jan A. J. Stolwijk Fellowship	Self-reported survey & measurement of drinking water samples	IDW well count, IDW² count within 5 km of residence, and distance to nearest active O&G well (km)	66 residents of Belmont County June–August 2016 Self-reported survey and drinking water samples	Age, sex, body-mass index, smoking status, educational status, marital status, employment status	**Self-reported health symptoms:** ID²W well count: Odds of reporting general symptoms ▲ respiratory ⬄ neurologic ⬄ dermal ⬄ gastro-intestinal ⬄
Blinn et al. (2020)	Other / General health outcomes	Southwest PA	Oil & natural gas	Heinz Endowments	Self-reported survey (health assessment reviewed by healthcare providers)	Cumulative well density (CWD), IDW of wells, and annual emission concentrations (AEC) from wells within 5 km (16,404 ft) of respondents' homes	104 health assessments 2012–2017 Self-selected survey conducted by Southwest Pennsylvania Environmental Health Project	Age, sex, smoker status	**Most commonly reported symptoms (CWD metric):** Headache ▲ Difficulty sleeping ▲ Sore throat ▲ Stress ▲ Itchy or burning eyes ▲ **Most commonly reported symptoms (IDW metric):** Headache ▲ Difficulty sleeping ▲ Sore throat ▲ Stress ▲ Itchy or burning eyes ▲
Rabinowitz et al. (2015)	Other / General health outcomes	Washington County, PA	Natural gas	Heinz Endowments, 11th Hour Project, Claneil Foundation, Jan Stolwijk Fellowship fund and Yale University Clinical and Translational Science Award grant	Health symptom survey	DNDW (distance to nearest drilled well) - Proximity of residence with ground-fed water supply to nearest well, <1 km (3,281 ft) to >2km (6,562 ft)	492 persons (180 households) Summer 2012 Random-sample environmental health assessment of reported health symptoms and health status	Age, sex, household education, smoking, awareness of environmental risk, work type, animal in house	**DNDW (<1 km (3,281 ft) vs. >2 km (6,562 ft)):** Dermal ▲ Upper respiratory ▲ Lower respiratory △ Cardiac △ Gastrointestinal △ Neurological △ **DNDW (1–2 km, 3,281–6,562 ft):** Dermal △ Upper respiratory △ Lower respiratory △ Cardiac △ Gastrointestinal △ Neurological △

Author (Year)	Health outcome category	Region	Primary hydro-carbon produced	Funder	Study design	Surrogate of exposure *(distance evaluated if specified)*	Sample size, study time frame, and outcome data source	Confounders and covariates considered	Main findings[1]
Tustin et al. (2016)	Other / General health outcomes	Central and Northeast, PA	Natural gas	NIH, Robert Wood Johnson Foundation, Degenstein Foundation, NSF	Self-administered questionnaire	IDW[2] from patient residence, incorporating well phase, well depth, daily gas production; exposure averaged across three months prior to survey	7,785 surveyed patients April 2014 Survey of patients from Geisinger Health System	Socioeconomic status, race/ethnicity, age, medical assistance, smoking status	Current chronic rhinosinusitis △ Migraine headaches △ Higher levels of fatigue △ Chronic rhinosinusitis & migraine △ Chronic rhinosinusitis & higher fatigue ▲ Migraine & higher levels of fatigue ▲ Migraine, fatigue & chronic rhinosinusitis ▲
Wein-berger et al. (2017)	Other / General health outcomes	Marcellus Shale, PA	Natural gas	Heinz Endowments	Structured health assessments (physician-reviewed)	Residence within 1 km (3,281 ft) of an unconventional natural gas well	135 health records collected among people concerned about unconventional natural gas development 2012–2015 Structured health assessment	Not considered	Statistical significance not assessed. **Symptoms reported by >20% participants:** Sleep disruption Headache Throat irritation Stress/anxiety Cough Shortness of breath Sinus problems Fatigue Nausea Wheezing
Saberi et al. (2014)	Other / General health outcomes	Marcellus Shale, PA	Natural Gas	NIEHS, NIOSH, Health Resources and Services Administration Center of Excellence in Environmental Toxicology at University of Pennsylvania	Self-reported, health symptom survey	Shale region residents (not formally evaluated)	72 residents in the Shale region Summer 2012 Structured health symptom survey administered in primary care clinics	Not considered	Statistical significance not assessed. Nine patients thought natural gas activity was a cause for medical symptom One had both symptoms & environmental concern included in medical record 22% of patients in area with extensive UNGD activity expressed concern about health related to UNGD. 12.5% of patients believed symptoms due to UNGD, including anxiety or sleep disturbances.

Author (Year)	Health outcome category	Region	Primary hydro-carbon produced	Funder	Study design	Surrogate of exposure *(distance evaluated if specified)*	Sample size, study time frame, and outcome data source	Confounders and covariates considered	Main findings[1]
Steinzor et al. (2013)	Other / General health outcomes	Oil & gas regions, PA	Natural gas	Colcom Foundation	Self-reported health symptom survey & subset of environmental sampling	Residents in "gas patches;" questionnaire included proximity to three gas facilities (within 1,500 ft (457 m) & outside this radius): compressor and pipeline stations, gas-producing wells, and impoundment or waste pits	108 individuals (children and adults) from 55 households August 2011–July 2012 Self-administered, structured health symptom survey Environmental sampling from subset of 70 participants	Not considered	**Reported health symptoms from residents ≤1,500 ft (457 m) vs. >1,500 ft (457 m) of natural gas facility:** Throat Irritation ▲ Sinus problems ▲ Nasal irritation ▲ Eye burning ▲ Joint pain △ Severe headaches ▲ Sleep disturbances △ Skin rash▲ Shortness of breath △ Forgetfulness △
Ferrar et al. (2013)	Other / General health outcomes	Marcellus Shale, PA	Natural gas	University of Pittsburgh Graduate School of Public Health, Environmental & Occupational Health Department	Longitudinal health symptom & stressor interview	Not evaluated	Session 1: 33 individuals May–October 2010 Session 2: 20 individuals (same individuals as session 1) January–April 2012 Interviews administered by phone or in-person	Not considered; discussed participant characteristics	Statistical significance not assessed. A total of 59 health impacts were attributed to Marcellus Shale development, and 13 stressors, with most common symptom being stress. Perception of health impacts increased from session 1 to 2; Stressors remained the same across sessions.

[1] Associations from studies that tested for statistical significance are represented using the following symbols: ▲=significant increase, ▼= significant decrease, ▽= non-significant decrease, △= non-significant increase, ⇔ = null findings/no association. Studies that did not test for statistical significance are noted in the table and results are briefly summarized. Unless explicitly stated, the summary of outcomes represents results from comparing the highest tertile/quantile/quartile/highest exposure category to the lowest exposure category. In other words, the increase or decrease in a health outcome is the highest exposure group compared to the lowest (or reference category).

Abbreviations: annual emissions concentration (AEC); antineutrophil cytoplasmic antibody (ANCA); body mass index (BMI), California Air Resources Board (CARB); congenital malformations (CM); cumulative well density (CWD); distance to nearest drilled well (DNDW); emergency department (ED), inverse distance weighted (IDW); migraine probability algorithm (MPA); myeloperoxidase (MPO); micrograms per cubic meter (µg/m3); persistent proteinase 3 (PR3); National Institutes of Health (NIH); National Institute of Environmental Health Science (NIEHS); National Institutes of Occupational Safety and Health (NIOSH); nitrogen dioxide (NO_2), particulate matter less than or equal to 2.5 microns ($PM_{2.5}$); unconventional natural gas development (UNGD); United States Environmental Protection Agency (US EPA).

3.4. Discussion

This chapter presents the findings of epidemiological studies on the association between upstream OGD exposures and adverse health outcomes conducted in the United States and Canada, including California. Here, we discuss (1) the strengths and limitations of environmental epidemiological research evaluating health risks and impacts associated with oil and gas development; (2) the need for broad consideration of the peer-reviewed literature across time and space; (3) evidence of disproportionate exposure and health risks; and (4) measures to mitigate health risk and impacts associated with oil and gas development.

3.4.1 Strengths and limitations of environmental epidemiological research evaluating health risks and impacts associated with oil and gas development

The proliferation of upstream OGD in several regions of the United States has been followed by a rapid growth in the peer-reviewed epidemiologic literature assessing the human health risks associated with exposure to upstream OGD. Below we describe the strengths and limitations of environmental epidemiological research in evaluating health risk and impacts associated with upstream OGD, in the context of exposure assessment, overall study design, addressing confounding factors, and considering geographic differences and temporal changes in regulation, extraction methods, etc.

3.4.1.1. Exposure assessment

Epidemiological studies employ various approaches to evaluate the association between upstream OGD and various adverse health outcomes. Surrogates of exposure used in epidemiological studies often include proximity to oil and gas wells, density of oil and gas wells, phase of well development, and cumulative volume of oil and/or natural gas produced (see *Surrogates of exposure to upstream oil and gas development*; **Table 3.1**). These surrogates of exposures are aggregate measures of the chemical, physical, and social stressors associated with upstream OGD.

Recent reviews of the literature that examine upstream OGD acknowledge the need for more robust exposure assessment methods to more accurately evaluate specific risk factors, such as exposure to air and water pollution associated with upstream OGD (Bamber et al., 2019; Deziel et al., 2020, 2022a; Health Effects Institute-Energy Research Committee, 2019; Shonkoff et al., 2014).

However, given the complexity of and multiple potential hazards and exposure pathways associated with upstream OGD, relying on aggregate metrics of exposure (e.g., proximity to wells, well density, etc.) offers advantages over the examination of exposure to one pollutant or one hazard at a time (Deziel et al., 2022a). These approaches enable epidemiologists to identify human health burdens that may otherwise be missed (Buonocore et al., 2020). Therefore, the body of epidemiological literature is crucial to consider when aiming to mitigate exposures and health burdens, as a narrow focus on one pollutant or pathway may be ineffective at reducing health burdens associated with multiple potential pathways.

Findings from previous studies have reinforced the need to consider stressors associated with upstream OGD from a broader perspective. For example, one study conducted in Pennsylvania found an asthma effect size that was much greater — almost an order of magnitude higher — than would be expected from exposure to criteria air pollutants alone (e.g., particulate matter [PM_{10}], nitrogen dioxide, ozone), suggesting that additional pollutants or other risk factors may be playing a role in the health effects observed (asthma exacerbation) (Rasmussen et al. 2016). Additionally, this body of epidemiological studies tend to place heavier focus on well sites as opposed to other oil and gas infrastructure (because of the public availability of geo-spatially explicit well data) though effects have still been observed in studies while adjusting for other upstream OGD sources (e.g., McKenzie et al., 2019a).

3.4.1.2. Addressing confounding factors

While residual confounders — unmeasured factors that might bias the observed associations — in epidemiological studies is always a possibility, such uncertainty has generally been well addressed in this body of peer-reviewed epidemiological studies. Over time, analytical epidemiological studies, such as cohort and case-control studies focused on upstream OGD in particular, have considered an increasing number of potential confounding variables and covariates in their study designs (see **Tables 3.2**–**3.7**), and epidemiologists have conducted sensitivity analyses among subsets of their study populations to further substantiate their findings. While the first studies examining adverse health outcomes reported inverse associations for certain outcomes (McKenzie et al., 2014), studies published since then have expanded upon the types of confounders considered and how exposure to upstream OGD is estimated. For example, recent studies looking at preterm birth include innovative exposure metrics that allow for a more detailed evaluation of exposure associated with upstream OGD (e.g., inclusion of phase of well pad, production volume, flaring activity) and indicate that adverse perinatal outcomes are still observed (Casey et al., 2016; Walker Whitworth et al., 2018; Cushing et al., 2020; Tran et al., 2020).

Additionally, certain causal inference study designs, such as difference-in-differences design, control for temporal changes in variables that might confound an observed association (Currie et al., 2017; Hill, 2018; Willis et al., 2018). Exposure misclassification is consistently a concern in environmental epidemiological studies. However, imprecision in exposure assessment or non-differential exposure misclassification is more likely to attenuate observed relationships (i.e., bias toward the null), thus leading to an underestimate of the true adverse impacts of upstream on perinatal outcomes (**Figure 3.10**) (Blanchard et al., 2018). In environmental epidemiologic studies, researchers often use surrogates to estimate exposures or assign individuals to exposure categories; these surrogates have some measurement error associated with them. When these errors in assigning or classifying participant exposures are similar between exposed and unexposed or those with or without the health outcome, this is referred to as non-differential exposure misclassification. This type of “noise” in the data tends to dilute or attenuate the true exposure-response relationship, as illustrated by the hypothetical dashed line in **Figure 3.10**, which has a shallower slope compared to the hypothetical “true” solid line. In the context of the literature on OGD-related exposures summarized in this chapter, this suggests that positive associations are likely not attributable to exposure misclassification and that effect sizes may in fact have been underestimated (Deziel et al., 2020).

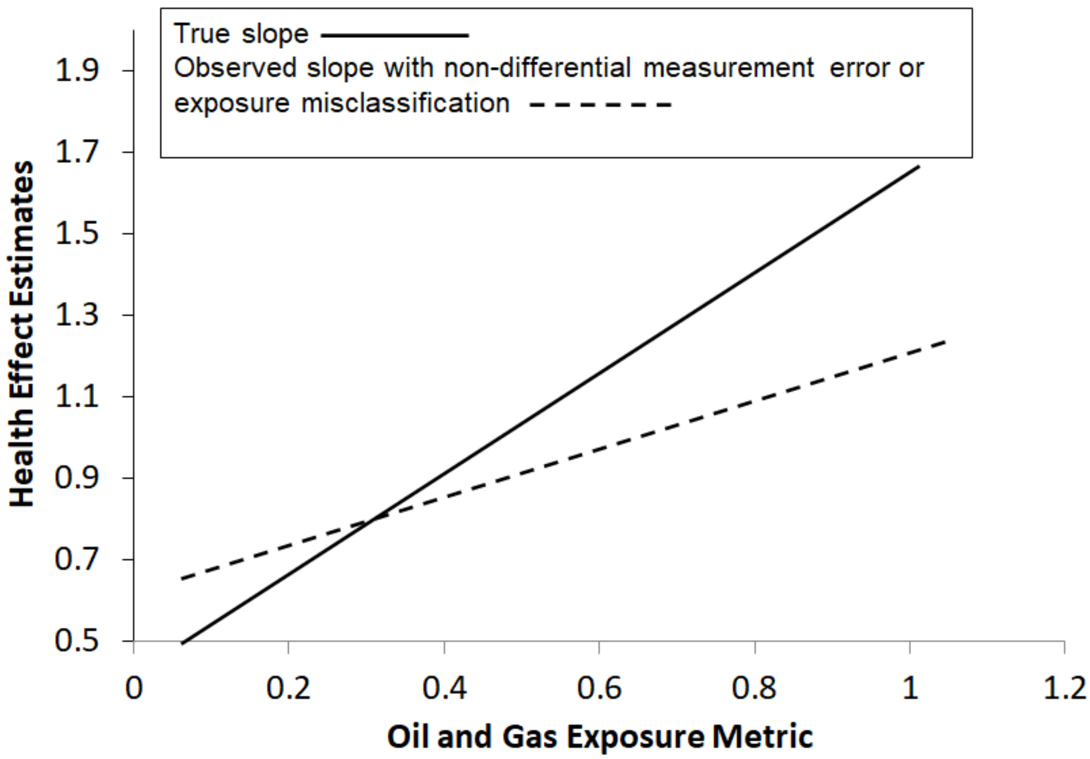

Figure 3.10. Potential effect of imprecise exposure estimates on a hypothetical exposure-response relationship. Source: Adapted from Seixas & Checkoway (1995).

3.4.1.3. Study design

Despite constraints inherent in environmental epidemiology — specifically, the reliance on observational study designs and surrogate measures of population-level exposure — retrospective study designs used in most of the published studies have accounted for both spatial and temporal aspects of past exposures, as well as complex exposure scenarios. Additionally, retrospective (longitudinal cohort and case-control) study designs are also able to establish temporality — that is that the exposure to OGD occurred prior to the health outcome. Registry-based studies, including those using birth certificate and cancer registry data, allow for inclusion of all adverse perinatal health outcomes, and therefore yield a low chance of selection bias.

Recent reviews of the literature that examine upstream OGD acknowledge the diversity of health outcomes, study design, geography of focus, and exposure assessment methodology among the peer reviewed literature introduce challenges to comparing adverse health outcomes across states, fields, and basins (Bamber et al., 2019; Deziel et al., 2020; Health Effects Institute-Energy Research Committee, 2019; Shonkoff et al., 2014). However, even when studies relying on hypothesis-generating designs (e.g., self-reported surveys, cross-sectional, ecological studies) are removed, the directionality observed in the remaining body of analytical epidemiological studies indicating upstream oil and gas development is associated with adverse health outcomes is preserved.

3.4.2 Broad consideration of the epidemiological literature across time and space

The epidemiological literature to date has examined potential associations between upstream OGD and increased health risks and impacts across hydrocarbon types, technological approaches to extraction, and regions throughout the United States and Canada. The body of epidemiological literature examining exposure to upstream OGD and adverse health outcomes encompasses three decades, with the most recent year examined being 2019 in California (**Figure 3.3**). Because of this, assessment of epidemiological literature should include consideration of factors that may no longer be applicable in the immediate present, such as changes in emission control technologies, regulatory contexts, and shifting petroleum geological target zones and associated technological approaches to hydrocarbon development.

Though the majority of studies that examine health risks associated with upstream OGD have been conducted outside of California, these studies are relevant to the California context for multiple reasons. First, many health-damaging pollutants (e.g., benzene, toluene, ethylbenzene, xylene, and hexane) emitted from upstream OGD activities occur naturally in petroleum reservoirs, regardless of the region. While the magnitude of emissions of health-damaging petroleum-associated compounds across environmental media may vary across site-specific conditions, the presence of these health hazards is intrinsic to OGD and are therefore consistently present across different geographical and geological contexts.

Second, while petroleum reservoirs may differ by oil and gas region, certain regional petroleum reservoir characteristics and technological approaches to upstream OGD in other regions are similar to those of California. For example, similar to California, Colorado produces oil and gas from geological zones with migrated oil and gas with the use of relatively shallow hydraulic fracturing and the application of enhanced oil recovery (EOR), similar to California (Long et al., 2015). Furthermore, the regulatory environment may influence the types and levels risk of health-damaging exposure associated with upstream OGD. While the regulation of OGD has evolved over time and may differ by jurisdiction, there are examples of overlap between the California regulatory landscape and that of other oil and gas states. Like California, Colorado has methane and VOC-emission control rules which — if properly enforced — may significantly reduce emissions of methane, toxic air contaminants, and other potentially health damaging air pollutants from certain types of infrastructure during upstream oil and gas development (CARB, 2021; CDPHE AQCC, 2019a, 2019b). Similar to California's Public Health Rulemaking Process, the Colorado Oil and Gas Conservation Commission (COGCC) recently underwent a mission change rulemaking after the adoption of Senate Bill 19-181 (SB 19-181) (Colo. S.B. 19-181, 2019). SB 19-181 changed the mission of the COGCC "from 'fostering' to 'regulating' OGD in a manner that protects public health, safety, welfare, the environment and wildlife resources" (CO DNR, 2020). Four peer-reviewed epidemiological analytical studies evaluating upstream OGD have been conducted in Colorado and found associations between upstream OGD and congenital heart defects and neural tube defects, childhood cancer, and markers of cardiovascular disease

(McKenzie et al., 2014, 2017, 2019a, 2019b). These studies may be particularly relevant to California, given similar types of regional petroleum geology (e.g., migrated oil), methods of oil and gas development (e.g., enhanced oil recovery and hydraulic fracturing of migrated oil deposits), and similar regulatory environments.

Third, while the vast majority of studies published in recent years outside of California focus on unconventional OGD (e.g., high-volume hydraulic fracturing and development of hydrocarbons from source rock), we reiterate the relevance of considering epidemiological studies on both conventional and unconventional OGD, as many chemical stressors (e.g., toxic air contaminants, criteria pollutants) and physical stressors (e.g., noise) are intrinsic to both conventional and unconventional OGD (for more information see Chapter 2, Section 2.5.1).

Given the similarities in hydrocarbons under production, petroleum reservoir characteristics, technological approach to extraction, and regulatory context between California and other regions where epidemiological studies have been conducted, most notably for Colorado, the body of epidemiologic literature is relevant to consider in assessing health risks and health impacts of upstream OGD in the California context. Further, consistency in findings across studies given this heterogeneity provides additional confidence that such studies are relevant to consider when assessing the health risks and burdens attributable to upstream OGD on California and how best to minimize them. An important guiding principle here is the precedent in the United States and elsewhere of governing bodies making decisions to protect health based on scientific evidence of environmental hazards elsewhere, such as the promulgation of National Ambient Air Quality Standards for particulate matter, despite differences in chemical composition and physical characteristics of particulates across different geographic regions and the range of intrinsic and extrinsic vulnerabilities among study populations (US EPA National Center for Environmental Assessment, 2019).

3.4.3 Disproportionate exposures and health risks

Epidemiological studies in California and other oil and gas regions have observed stronger associations between exposure to upstream OGD and adverse health effects among vulnerable subpopulations. In California, Gonzalez et al. (2020) reported associations between exposure to upstream OGD and preterm birth at 28–31 weeks, that, in a stratified analysis by maternal race/ethnicity and educational attainment, were restricted to Hispanic mothers. The stratified analysis also revealed that exposure to new and active wells was associated with preterm birth at 20–27 weeks, 28–31 weeks, and 32–36 weeks among mothers with less than a high school education. Additionally, Johnston et al. (2021) noted that the majority of the study participants within 1,000 m (3,281 ft) of active oil and gas sites in South Los Angeles identify as Hispanic/Latinx and reported reduced lung function on average to be significant among adults, Hispanic/Latinx residents and participants over the age of 60 if living downwind and within 200 m (656 ft) of a well site. Of note, effect sizes in reductions in lung function by Johnston et al. (2021) are similar in magnitude to reductions in lung function associated with secondhand smoke exposure among women (Eisner, 2002) and reductions in lung function among adults living near busy roadways (Kan et al., 2007). In oil and gas regions outside of California, health inequities have also been observed among population subsets. For example, Casey et al. (2019) reported a stronger association between exposure to unconventional natural gas development and antenatal anxiety and depression during pregnancy among mothers receiving Medical Assistance (an indicator of low family income) in Pennsylvania. Additionally, in Texas, Cushing et al. (2020) found that exposure to nightly oil and gas-associated flare events was associated with increased odds of preterm birth and shorter gestation, and that in a stratified analysis, these findings were restricted to Hispanic women.

3.4.4 Strategies to reduce human health hazards, risks, and impacts from upstream OGD activities

The body of science reviewed by the Panel for this report strongly supports the need for additional protections (such as setbacks) for populations existing in close proximity to upstream OGD. Although additional research on the impacts of upstream OGD would be helpful, this should not be used as a reason to delay regulatory action to reduce exposure to OGD-related hazards.

Existing epidemiologic studies were not designed to test and establish a specific “safe” buffer distance between upstream OGD sites and sensitive receptors, such as homes and schools. Nevertheless, studies consistently demonstrate evidence of harm at distances less than 1 km (3,281 ft), and some studies also show evidence of harm linked to upstream OGD activity at distances greater than 1 km (3,281 ft). In addition, exposure pathway studies have demonstrated through measurements and modeling techniques, the potential for human exposure to numerous environmental stressors (e.g., air pollutants, water contaminants, noise) at distances less than 1 km (3,281 ft) (e.g., Allshouse et al., 2019; DiGiulio & Shonkoff, 2021; Holder et al., 2019; McKenzie et al., 2018; Soriano et al., 2020), and that the likelihood and magnitude of exposure decreases with increasing distance.

Figure 3.11 presents a hierarchy of strategies to reduce human health hazards, risks and impacts from upstream OGD activities. **Table 3.9** presents the advantages and disadvantages of each strategy from an environmental public health perspective.

At the top of **Figure 3.11** is the most health protective strategy: to stop drilling and developing new wells, phase out existing upstream OGD activities and associated infrastructure, and properly plug remediate legacy wells and ancillary infrastructure. This approach is being considered or adopted by various states and municipalities.

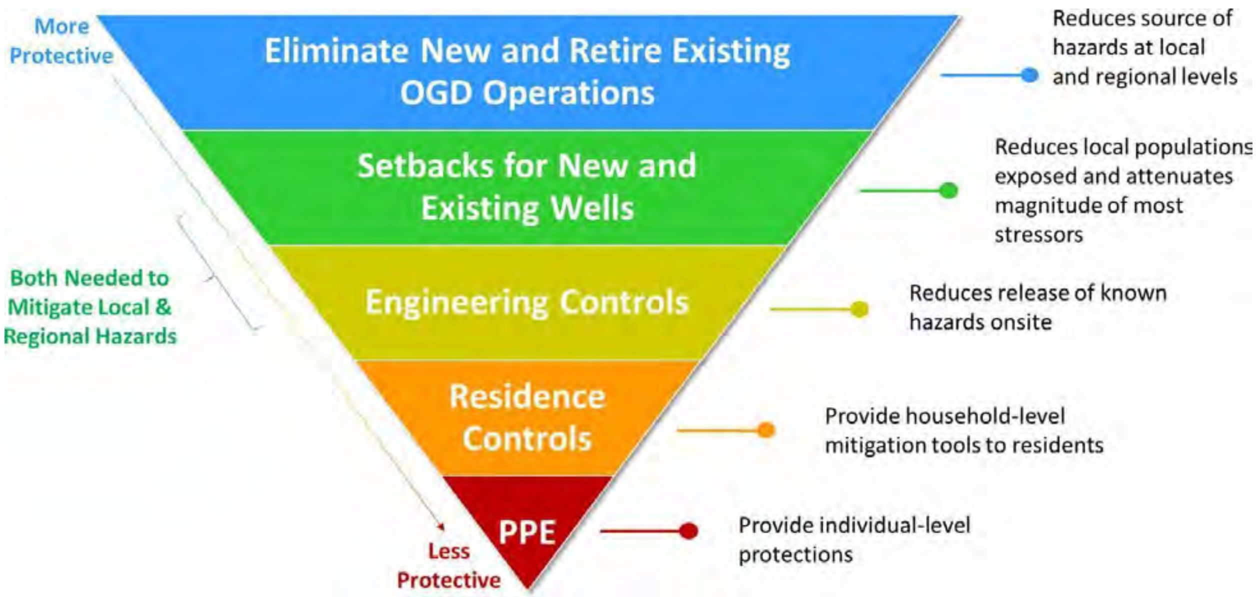

Figure 3.11. Hierarchy of controls to reduce public health harms from oil and gas development activities Source: Figure 1, Deziel et al. (2022b).

For example, unconventional OGD (i.e., hydraulic fracturing or 'fracking') has been eliminated in Vermont, Maryland, New York, and Washington, which vary in available reserves. The Delaware River Basin (DRB) Commission prohibited fracking in the DRB region, which covers parts of New York, Pennsylvania, New Jersey, and Delaware, in order to protect drinking water (DRBC, 2021). Because these bans are specific to fracking, they do not eliminate conventional wells or orphaned and abandoned wells. However, some municipalities are moving towards complete upstream OGD elimination, including Los Angeles, which has approved a ban of all new conventional and unconventional oil and gas wells and a phase-out of existing wells (LACBS, 2021).

If the development of oil and gas is to continue, the greatest health benefits would be gained from a strategy that includes the next two controls in the hierarchy depicted in **Figure 3.11**: the elimination of new and existing wells and ancillary infrastructure within scientifically informed setback distances, and the deployment of engineering emission controls and associated monitoring approaches that lead to rapid leak detection and repair for new and existing wells and ancillary infrastructure. Because air pollutant concentrations and noise levels decrease with increasing distance from a source, adequate setbacks can reduce harm to local populations by reducing exposures to air pollutants and noise directly emitted from the OGD activities. However, setbacks do not reduce harms from upstream OGD contributions to regional air pollutant levels, such as secondary particulate matter and ozone, nor greenhouse gases such as methane, which are nearly always co-mingled with health-damaging air pollutants (Michanowicz et al., 2021). As compared to other pollutant-specific or pathway-specific policy measures (e.g., implementation of chemical additive restrictions or additional emission control requirements), the implementation of a minimum surface setback distance is a policy measure that considered the real-world scenarios of multiple stressors associated with upstream OGD but makes allowance for some continued oil and gas production. Setback distances between a source and a receptor are utilized in other federal, state, and local settings to mitigate harms associated with a given source. Engineering controls that reduce emissions at the well site are also necessary to reduce these harms.

Engineering controls include cradle-to-grave noise and air pollution emission mitigation controls on OGD infrastructure — including new, modified and existing infrastructure — and proper abandonment of legacy infrastructure, prioritizing those nearest to residential sites and schools and those associated with the highest emissions, leaks and other environmental hazards.

However, engineering controls can fail and engineering solutions may not be available for or economically feasible to handle all of the complex stressors generated by upstream OGD, including multiple sources and types of air pollution, noise pollution, light pollution, water pollution, and other stressors. Therefore, neither setbacks or engineering controls alone are sufficient to reduce the health hazards and risks from OGD activities — both approaches are needed in tandem.

Finally, we note that while outside of CalGEM's jurisdiction, setbacks for new construction of housing or schools at a certain distance from existing or permitted OGD sites (commonly referred to as reverse setbacks) should be considered.

Table 3.9. Advantages and disadvantages of oil and gas development (OGD) control strategies from an environmental public health perspective. Source: Table 1, Deziel et al. (2022b).

Control	Description	Advantage	Disadvantage
Elimination	Eliminate new wells, properly plug existing wells, and remediate ancillary infrastructure.	Eliminates the source of nearly all environmental stressors (e.g., air and water pollutants, noise); protects local and regional populations; largest reduction in carbon emissions.	May require a long-term approach due to economic, legal, political dynamics and energy reliability considerations, the need to address both conventional and unconventional wells, and the unknown location of many abandoned wells.
Setbacks	Establish a protective buffer zone between OGD hazards and sensitive receptors.	Reduces risk of exposures to populations living near OGD sites; environmental stressors are generally attenuated with increasing distance.	Setbacks alone without coupled engineered mitigation controls allow continued release of hazards. There is no universal setback that would adequately address regional air quality issues and emissions of climate-warming gases from OGD.
Engineering controls	Reduce or eliminate release of specific environmental hazards on site.	Reduces or eliminates certain hazards and therefore can have local and regional environmental public health benefits.	Tends to be disproportionately focused on air pollutant emissions and noise, and thus fails to address other pathways of exposure, including via water resources. Often not feasible to apply engineering solutions to multiple, complex hazards each requiring different control technologies (e.g., noise, air and water impacts, odors, light pollution) and lacks the important factor of safety provided by a setback when engineering controls fail.

Control	Description	Advantage	Disadvantage
Residence controls	Households deploy devices and strategies to reduce exposure to indoor environmental hazards at the household/school-level (e.g., water filter, light-blocking shades, air filters).	Reduces intensity of certain hazards to nearby communities at the household level.	Places burden on individuals and households to use and maintain devices properly to maximize effectiveness. Not feasible to apply devices to address numerous, complex stressors. Does not adequately address impacts of ambient air pollutant and greenhouse gas emissions from OGD on regional air quality and the climate.
Personal protective equipment	Individuals wear protective equipment to reduce exposure to environmental hazards (e.g., respiratory masks, ear plugs, eye masks).	Reduces intensity of exposure of certain hazards to nearby individuals.	Places burden on individuals to use PPE consistently and properly. May not be feasible for understudied stressors or certain environmental toxicants. Does not address impacts of air pollutant and greenhouse gas emissions from OGD on regional air quality and the climate.

3.5. Summary

Our review included 72 peer-reviewed epidemiological studies in the United States and Canada, six of which are from California, that evaluated the relationships between upstream oil and gas development and adverse health outcomes. Studies in California observed associations between upstream OGD and diagnosed asthma, reduced lung function, and reduced fetal growth at distances of up to 1 km (0.62 mi or 3,281 ft). Studies in California evaluating the relationship between upstream OGD development and risk of preterm birth reported inconsistent results. One California study did not observe an association between upstream oil and gas development and migraine headaches. The Panel concluded that the totality of the epidemiological evidence from 25 studies (three from California) provides a high level of certainty for a causal relationship between residential exposure to upstream OGD and poor perinatal outcomes. The Panel also concluded that the epidemiologic evidence (11 studies, two from California) provides a high level of certainty for a causal relationship between residential exposure to upstream OGD and adverse respiratory outcomes. These conclusions were reached because of the consistency of results across multiple studies that were conducted using different methodologies, in different locations, with diverse populations, and during different time periods. Numerous other health endpoints have been examined and are summarized herein. Most studies report statistically significant associations between oil and gas development and adverse health effects across different geological regions, in both urban and rural settings, and when examining different extraction methods (e.g., high-volume hydraulic fracturing and enhanced oil recovery approaches such as cyclic steam injection and water flooding). Epidemiological studies have observed consistent associations between upstream OGD and adverse health effects while considering different exposure assessment methods, including proximity of human receptors to oil and gas sites, nearby well density, well depth, production volume, and phase of well pad development (e.g., pad preparation, drilling, stimulation, production). In summary, the body of literature indicates upstream OGD is associated with adverse health impacts in nearby populations.

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Appendix C.

C.1. List of Key Terms for Literature Search

List S1. Key Terms Used in Epidemiological Assessment Web of Science Boolean search conducted July 15, 2023.

TS=(“oil and gas” OR shale OR petroleum OR “natural gas” OR “shale gas” OR “tight gas” OR “tight resource” OR “shale oil” OR “tight oil” OR “unconventional gas” OR “unconventional oil” OR “unconventional resource” OR “conventional gas” OR “conventional oil” OR “conventional resource” OR “natural gas liquids” OR drilling OR “well stimulation” OR “hydraulic fracturing” OR fracking OR flar* OR “coalbed methane” OR “well head” OR wellbore OR “casing head” OR “well pad” OR “abandoned well” OR pipeline* OR “oil well” OR “gas well”) AND TS=(“Health” OR “epidemiological” OR “symptom*” OR “health risk*” OR “occupational health” OR “physiological” OR “psychological” OR “hospitalization” OR “asthma” OR “injury” OR “mortality” OR “cancer” OR “morbidity” OR “adverse pregnancy outcomes” OR “birth” OR “congenital” OR “birth defects” OR “birth weight” OR “low birth weight” OR “preterm birth” OR “premature birth” OR “preterm delivery” OR “small for gestational age” OR “LBW” OR “PTB” OR “PTD” OR “SGA” OR “fetal death” OR “mental health” OR “cardiovascular” OR “exposure”) NOT TS=(Europe OR Australia OR China OR India OR “Middle East” OR Africa) AND TS=(“U.S.” OR “United States” OR USA OR Canada OR “North* America” OR Alabama OR Alaska OR Arizona OR Arkansas OR California OR Colorado OR Connecticut OR Delaware OR Florida OR Georgia OR Idaho OR Hawaii OR Illinois OR Indiana OR Iowa OR Kansas OR Kentucky OR Louisiana OR Maine OR Maryland OR Massachusetts OR Michigan OR Minnesota OR Mississippi OR Missouri OR Montana OR Nebraska OR Nevada OR “New Hampshire” OR “New Jersey” OR “New Mexico” OR “New York” OR “North Carolina” OR “North Dakota” OR Ohio OR Oklahoma OR Oregon OR Pennsylvania OR “Rhode Island” OR “South Carolina” OR “South Dakota” OR Tennessee OR Texas OR Utah OR Vermont OR Virginia OR Washington OR “West Virginia” OR Wisconsin OR Wyoming OR “Washington DC” OR “Washington D.C.” OR “D.C.” OR “District of Columbia” OR “Canada” OR “British Columbia” OR Anadarko OR Ardmore OR Arkoma OR Appalachian OR Devonian OR Bakken OR Barnett OR Chattanooga OR Cherokee OR Delaware OR “Denver-Julesburg” OR “Eagle Ford” OR Fayetteville OR “Fort Worth” OR “Greater Green River Basin” OR “Front Range” OR Haynesville OR Inglewood OR Marcellus OR Monterey OR Niobrara OR Permian OR “Powder River” OR Piceance OR Rogersville OR Saskatchewan OR San Juan OR Uinta OR Utica OR Wattenberg OR Williston OR “Wind River Basin” OR Woodford OR Wolfcamp OR “Four Corners” OR “Canadian Oil Sands”)

C.2. Summary of studies evaluating sexually transmitted infections

Six studies focused on the effects of oil and gas development on rates of sexually transmitted infections (STIs) (Beleche & Cintina, 2018; Cunningham et al., 2020; Deziel et al., 2018; Huseth-Zosel et al., 2021; Johnson et al., 2020; Komarek & Cseh, 2017). This is an area of concern, as the influx of non-local, specialized workers can result in changes to the local labor market when an area is flagged for new oil and gas development (Johnson et al., 2020). Studies conducted in Pennsylvania, Texas, North Dakota, and Ohio found counties with fracking activities to have higher rates of gonorrhea and chlamydia infections compared to counties without oil and gas development (Beleche & Cintina, 2018; Deziel et al., 2018; Huseth-Zosel et al., 2021; Johnson et al., 2020). Similarly, in the Marcellus Shale region of Pennsylvania and in the general United States, oil and gas development was found to be associated with higher rates of gonorrhea compared to the comparison group (Cunningham et al., 2020; Komarek & Cseh, 2017).

The minority of studies found no association with rates of STIs. Two studies found no association between oil and gas development and rates of syphilis (Deziel et al., 2018; Johnson et al., 2020). Similarly, no association was found between oil and gas development and rates of STIs in Colorado and North Dakota counties (Johnson et al., 2020). Similarly, no association was found between oil and gas development and rates of STIs in Colorado and North Dakota counties (Johnson et al., 2020).

CHAPTER FOUR

Oil and Gas-Associated Air Pollution, Health Risks and Approaches to Emission Control

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4.0. Abstract

Upstream activities related to oil and gas development (OGD) (e.g., production and processing) in California — and across the United States — emit numerous air pollutants. While OGD in California is declining overall, dense upstream oil and gas activities still occur in many regions of the state. The San Joaquin Valley and South Coast Air Basins are the largest oil and gas producing regions in California, both of which have some of the worst air quality in the state. Findings suggest that emissions from upstream oil and gas may significantly impact regional air quality within specific regions of California, such as the San Joaquin Valley. In regions where upstream oil and gas is only a small contributor to the region's ambient air quality levels, such as the South Coast Air Basin, emissions from upstream OGD sites still pose a risk to residents and other sensitive receptors located nearby. More than 3 million people live within 1 km (3,281 ft) of an oil and gas well in California. Therefore, the health hazards from upstream OGD still present a significant issue given that proximity to upstream OGD is a health risk factor.

A review of one California-specific health risk assessment identified 38 air pollutants near upstream oil and gas sites, including 22 compounds listed as known or suspected human carcinogens. Toxic air contaminants (TACs) associated with upstream OGD include diesel exhaust; benzene, toluene, ethylbenzene, and xylenes (BTEX); formaldehyde; n-hexane; styrene; hydrogen sulfide (H_2S); and 1,3-butadiene, among others. Cancer risk during specific upstream oil and gas processes (i.e., hydraulic fracturing activities, cleanout events) exceeded the U.S. Environmental Protection Agency *de minimis* threshold (one case in one million), the South Coast Air Quality Management District (SCAQMD) significance thresholds of 1, 10, and 25 in one million, and the San Joaquin Valley Air Pollution Control District (SJVAPCD) significance thresholds of 1 and 20 in one million excess cancers.

In California, regulatory exemptions from vapor recovery, leak detection and repair (LDAR), and equipment change-out requirements have been established based on methane and non-methane volatile organic compound (NMVOC) emissions from specific upstream oil and gas sources. These exemptions include, but are not limited to (1) a statewide zero-bleed/zero-emission standards exemption for existing low-bleed (<6 standard cubic feet per hour) natural-gas driven pneumatic devices installed prior to January 1, 2016; 2) an exemption from the statewide 95% vapor recovery requirement for low-throughput separators and condensate tank systems; and (3) an exemption from the statewide leak detection and repair (LDAR) requirement for upstream oil and gas infrastructure components associated with heavy oil (API gravity <20).

The closure of the exemptions from statewide zero-bleed/zero-emission standards for existing low-bleed pneumatic devices and vapor recovery requirements for low-throughput separates and condensate tank systems would reduce non-methane volatile organic compound (NMVOC) emissions, which include TACs, by an estimated 15 tons per year (tpy) from 50 existing natural gas powered pneumatic devices and 208 tpy from ~2,200 small throughput separator and tank systems. Additionally, the California Air Resources Board (CARB) states that heavy oil components (API gravity <20) exempt from LDAR account for less than 1% of hydrocarbon

emissions from leaking components. While these exemptions represent a small fraction of NMVOC emissions from the statewide upstream oil and gas development sector, these emissions may be meaningful to risk of TAC exposure in areas with concentrated exempt infrastructure or when this infrastructure exists in close proximity to human populations.

LDAR focused on monitoring for methane is useful when monitoring equipment with emissions that have high methane/non-methane hydrocarbon ratios. In this context, methane can be a reasonable indicator of the presence of TACs and other NMVOCs that are intermixed with methane. However, when monitoring emissions from infrastructure or processes containing gases with low methane/non-methane ratios (e.g., condensate tanks, produced water management and disposal, etc.) or little to no methane content (e.g., combustion from diesel engines, combustion emission from natural gas-powered equipment, etc.), methane is not a reliable indicator of TAC and other NMVOC emissions and there is likely no surrogate for these situations. LDAR approaches that focus on measurement of large suites of air pollutant species may be more comprehensive and appropriate for various applications when gas composition is uncertain.

Our findings suggest there are numerous additional emission control measures (including regulatory setback distances) that could be implemented in California to further reduce emissions from upstream OGD and protect the health of residents in proximity to activity. Agencies with jurisdiction should deploy measures to reduce exposure to air pollution associated with upstream OGD sites, including but not limited to LDAR requirements and increased emission control.

4.1. Introduction

Over the past 15 years, the United States has seen unprecedented growth in domestic upstream oil and gas development (OGD) and production (Bamber et al., 2019; Deziel et al., 2020; Shonkoff et al., 2014). Due to technological advancements in high-volume hydraulic fracturing, directional and horizontal drilling, and dense spatial clustering of wells, previously inaccessible petroleum resources, such as tight sand and source rock formations (e.g., shale, sandstone, coal seams), have become more accessible and economically viable (Bamber et al., 2019; Deziel et al., 2020; Shonkoff et al., 2014). Since 2005, these techniques, collectively referred to as unconventional OGD, have resulted in a boom of tight oil and gas production in the United States, especially in states with active shale plays such as Colorado, Louisiana, New Mexico, North Dakota, Ohio, Oklahoma, Pennsylvania, Texas, West Virginia, and Wyoming (US EIA, 2019, 2020). Both conventional and unconventional OGD continue to be a prominent industry in specific regions of California, including the San Joaquin Valley and South Coast Air Basins (CalGEM, 2021a; CCST, 2015).

This section summarizes the air quality and health risk impacts from upstream OGD in California and elsewhere.

Components of upstream OGD

Upstream components of the oil and gas industry supply chain are separated into two main categories: oil and gas production (including exploration efforts) and processing (Adgate et al., 2014; Johnston et al., 2019; NRC, 2014; Shonkoff et al., 2014). Primary components of production include the well pad, which encompasses wells and related casing head, tubing head, and Christmas tree piping. Additional components include any pumps, compressors (associated with production side), heater treaters, separators, storage vessels, pneumatic devices, and dehydrators used at oil and gas facilities for production and processing (Adgate et al., 2014; Johnston et al., 2019; NRC, 2014; Shonkoff et al., 2014). Some of the available studies in the peer-reviewed literature evaluate emissions from production facilities as a whole, which would measure emissions from all these components collectively, while other studies have measured emissions from individual components (Adgate et al., 2014; Johnston et al., 2019; NRC, 2014; Shonkoff et al., 2014).

Production also involves the use of combustion equipment, such as drill rigs and service trucks, which are often diesel or gas powered. In production emissions, we also count well development, which includes well drilling activities such as the completion and recompleting of the portable non-self-propelled apparatus of the well. Stand-alone sites where oil, condensate and produced water and gas from several wells are separated, stored and treated are also considered. Finally, we include low pressure, small diameter, gathering pipelines and related components that collect and transport oil, gas and other materials and wastes from the wells to the refineries or gas processing plants (Adgate et al., 2014; Johnston et al., 2019; NRC, 2014; Shonkoff et al., 2014).

Processing consists of separating certain hydrocarbons and fluids from the oil and gas to produce pipeline quality oil and dry gas (CARB, 2013a). Some processing can be accomplished in the production segment, but the majority is performed in post-production. For upstream emissions, we consider the former. The components of processing include oil and condensate separation, water removal, separation of gas liquids, sulfur and carbon dioxide removal, fractionation of gas liquids, carbon dioxide capture, and gas processing. Emissions from idle, and/or orphaned wells are also considered, the results of which are summarized in Chapter 6 of this report.

4.2. Review of existing emissions data, air quality impacts, and related health risks

Upstream activities related to OGD emit numerous chemical pollutants into air, water, and soil. People that live, work, or attend school near oil and gas wells are exposed to these pollutants through several exposure pathways, including inhalation via the nose and mouth, ingestion through the mouth, and dermal absorption through the skin.

4.2.1. Characterization of air pollutants from upstream oil and gas in California

The primary focus for this section is to review studies that evaluate air pollution from upstream OGD in California.

Air pollutant emissions associated with upstream OGD

Upstream activities include the transport of equipment and materials to and from the well pad; well drilling, mixing, handling, and injection of oil and gas chemicals (including during well stimulation and routine maintenance operations), and management of recovered fluids and other waste products (Adgate et al., 2014; Johnston et al., 2019; NRC, 2014; Shonkoff et al., 2014). Well stimulation treatments include methods such as hydraulic fracturing, matrix acidizing, and acid fracturing, which are used to access hydrocarbons from previously-inaccessible tight geological formations, such as shale (CCST, 2015). Sources of air pollutants include products of incomplete combustion from flares and diesel-powered equipment, which emit carbon monoxide (CO), hydrocarbons, black carbon, diesel particulate matter (DPM) (a known carcinogen), and carbonyls, as well as chemicals emitted from surface and subsurface equipment such as wells, pumps, generators, compressors, pneumatic devices, tanks, surface impoundments, and solid and liquid waste handling equipment. External combustion equipment used during upstream OGD include boilers, heaters/treaters, and vapor recovery systems such as flares, incinerators, and thermal oxidizers; internal combustion equipment includes generators, pumps, accumulators, and turbines (CARB, 2013a). In 2007, California had an estimated 1,630 external combustion “units” (the majority of which were 5–10 years old) and 3,290 internal combustion “units” in operation (the majority of which were 10 years old or less) (CARB, 2013a).

Air pollutant emissions from upstream OGD include toxic air contaminants (TACs) (e.g., benzene, H_2S, hexane), criteria air pollutants (CAPs), sulfur oxides (SO_x), nitrogen oxides (NO_x), volatile organic compounds (VOCs) and reactive organic gases (ROG). The latter three are associated with the formation of tropospheric ozone (i.e., smog). ROG, SO_x, and NO_x emissions are also known precursors for secondary $PM_{2.5}$ formation (SJVAPCD, 2018). $PM_{2.5}$ can be emitted directly or formed indirectly through a set of chemical reactions between pollutants such as NO_x (Brandt et al., 2015).

The method of hydrocarbon extraction is not important from a toxic air contaminant (TAC) exposure perspective. Many TACs are co-produced with upstream OGD because of their natural occurrence in oil and gas reservoirs, regardless of whether hydraulic fracturing and other forms of well stimulation are used, such as acid fracturing or matrix acidizing (Garcia-Gonzales et al., 2019a). TACs such as benzene may be emitted to the atmosphere during the relatively brief amount of time that well stimulation treatments take place. Any produced water or products extracted from wells that contain TACs are of concern, particularly those that can become airborne.

The environmental public health literature strongly implicates geographic proximity to active upstream OGD as an important risk factor for a variety of adverse health outcomes. The overwhelming majority of studies that have assessed associations between upstream OGD and emissions of TACs have identified a number of regularly emitted pollutants, including: diesel exhaust; benzene, toluene, ethylbenzene, and xylenes (BTEX); n-hexane; styrene; and 1,3 butadiene, among others (Garcia-Gonzales et al., 2019a). Few studies found no association between proximity and TAC concentrations.

Intermittent peaks in air pollutant emissions from upstream oil and gas activities and equipment have also been observed (Allen, 2014; Brown et al., 2014). While these emissions may have a limited influence on regional air pollutant concentrations, they are likely to be associated with increased health-relevant exposures to local populations near emission sources. As such, studies that focus on regional concentrations of air pollutants associated with upstream OGD may arrive at estimates of low- to moderate-level chronic exposures experienced by regional populations, but in order to capture the full range of potential public health risks at the local level, it is important to consider the proximity of receptors to sources (Gonzalez et al., 2022; McKenzie et al., 2018; Pétron et al., 2014; Shonkoff et al., 2015a).

Methane and non-methane volatile organic compounds (NMVOCs) are emitted during upstream OGD (e.g., Koss et al., 2015; Rich et al., 2014; Marrero et al., 2016; see Section 4.4.1). Many of the NMVOCs and emitted are TACs or ground-level ozone precursors. Because both methane and some NMVOCs have a common source, certain infrastructure components, such as wellheads, gas pipelines, and gas processing plants, have emission profiles with high methane:non-methane hydrocarbon ratios. However, other components, such as condensate tanks, and produced water ponds, have emission profiles with far lower methane:non-methane hydrocarbon ratios, and methane is not a reliable indicator of NMVOCs that are not hydrocarbons. While diesel engines used for transport pumps and other purposes do not emit methane and have a zero methane:non-methane hydrocarbon ratio, they do emit criteria air pollutants (CAPs), TACs, and other air pollutants.

4.2.1.1 Composition of upstream oil and gas in California

Publicly available data concerning the composition of gas and the presence of NMVOCs and TACs in upstream oil and gas activities in California is limited. When gas composition data is available, analyses primarily focus on the characterization of light alkanes (C1–C6 hydrocarbons), nitrogen, oxygen, and other trace gases. Heavier hydrocarbons, including compounds of interest with regard to human health impacts (e.g., BTEX), are commonly reported as undifferentiated C6+ compounds (i.e., heavier alkanes) (USGS, 2014) or grouped together based on a range of carbon numbers (e.g., C5–C8). Analyses of gas in California for individual NMVOCs and TACs are not widely available.

The U.S. Geological Survey Energy Resources Program Geochemistry Laboratory Database (USGS EGDB) (USGS, 2014) is an important resource for analytical data for crude oil and gas samples from both California, and around the world. Analytical data is compiled from a variety of sources, including the USGS EGDB, other contracted laboratories, published literature, and unpublished public domain sources.

The USGS EGDB contains analytical data for gas sampled from 827 unique American Petroleum

Institute identifications (API)[1] in California; however, information regarding analytical methods, detection limits, non-detect and not measured parameter reporting, and sampling methods, dates, and locations is incomplete. Without additional context and documentation, it is unclear if constituents of interest (e.g., BTEX compounds) were measured and not detected, or if they were not measured at all. Thus, it is difficult to analyze and draw conclusions from these data with confidence.

A subset of gas samples in the USGS EGDB, originating from a 2007 USGS report on upstream OGD in the San Joaquin Basin (Lillis et al., 2007), was identified for further analysis based on the availability of background information regarding methodology, measured parameters, and sampling locations. In the report, 66 gas samples from oil and gas wells, tanks, and separators from six counties in the San Joaquin Basin were analyzed for gas composition, including select chemicals relevant to human health (i.e., benzene, n-hexane, H_2S) (Lillis et al. 2007). Statistical data from this report are summarized in **Table 4.1**. Of the 66 analyzed samples, benzene was detected six times, H_2S was detected three times, and n-hexane was reported 30 times. When reported, median concentrations of benzene, H_2S, and n-hexane were 0.04 mole percent (400 parts per million by volume, ppmv), 0.03 mole percent (300 ppmv), and 0.09 mole percent (900 ppmv), respectively. Detection limits for individual gas constituents were not explicitly stated in the study; non-detection does not mean a constituent was not present, and it possible the constituent is present below the detection limit.

It is important to note that these data represent a small fraction of oil and gas wells in California. Due to the limited data on upstream gas composition in California, it is difficult to ascertain how prevalent and at what concentrations pollutants are present in upstream sources. Additional testing and public disclosure of the composition of NMVOCs in upstream gas is needed to assess air pollution health risks and better inform policy makers.

[1] An API well number, or API number, is a unique numeric identifier assigned to each well permitted to drill in the United States. These API numbers are established by the American Petroleum Institute.

Table 4.1. Major components of gas from oil and gas wells in the San Joaquin Valley. Source: Lillis et al. (2007); USGS (2014).

Constituents	No. of detections[1]	Min (Mole%)	5th Percentile	Median (Mole%)	Mean (Mole%)	95th Percentile (Mole%)	Max (Mole%)
Nitrogen[2]	66	0.23	0.74	2.92	6.44	26.23	39.21
Oxygen and Argon[3]	66	0.07	0.16	0.77	1.14	3.13	8.13
Helium	1	0.11	0.11	0.11	0.11	0.11	0.11
Hydrogen	1	4.1	4.1	4.1	4.1	4.1	4.1
Carbon Dioxide	61	0.03	0.12	1.05	5.55	17.51	92.24[4]
Methane	66	1.722	56.3	81.2	77.02	95.44	97.53
Ethane	64	0.04	0.07	3.49	4.23	10.36	16.03
Propane	62	0.02	0.03	2.75	3.64	12.08	13.1
iso-Butane	57	0.02	0.02	0.52	0.8	2.36	3.74
n-Butane	46	0.04	0.1	1.4	2.1	6.11	8.4
iso-Pentane	45	0.02	0.02	0.16	0.31	0.9	1.97
neo-Pentane	7	0.02	0.02	0.02	0.03	0.07	0.09
n-Pentane	40	0.02	0.02	0.29	0.38	0.97	1.36
n-Hexane	30	0.02	0.02	0.09	0.14	0.34	0.42
n-Heptane	12	0.02	0.02	0.04	0.06	0.14	0.18
Benzene	6	0.02	0.02	0.04	0.04	0.06	0.06
Hydrogen Sulfide	3	0.02	0.02	0.03	0.03	0.04	0.04

[1] Detection limits for individual constituents were not provided in this study
[2] High nitrogen values are due to possible air contamination
[3] Measured oxygen and argon concentrations are assumed to be from air contamination
[4] High CO_2 and low methane in one sample possibly due to being taken from surface casing of producing well

4.2.1.2 Emissions from upstream OGD in California

In 2007, the California Air Resources Board (CARB) conducted a survey of the oil and gas industry in California, referred to herein as the “2007 Oil and Gas Survey” (CARB, 2013a). The 2007 Oil and Gas Survey gathered information on the various equipment and emissions associated with crude oil and gas production, processing, and storage in California.

The survey categorizes sources into three distinct categories: combustion, vented, and fugitive emissions. Combustion emissions are released from equipment that converts fuel to energy, whereas vented and fugitive emissions encompass the intentional (vented) and unintentional (fugitive) releases of vapors to the air (CARB, 2013a). As summarized in **Table 4.2**, 93% of carbon dioxide equivalents (CO_2e) emissions emitted during the production, processing, and storage of oil and gas in California come from combustion sources, with fugitive and vented emissions accounting for just 7% of total CO_2e emissions (CARB, 2013a). Similarly, facilities with the primary business types “onshore crude production” and “other” (i.e., compressed gas compression and marketing, cogeneration, combined heat and power, electricity generation, portable heating, water disposal, vapor recovery services) were responsible for 85% of the total CO_2e and ~48% of methane generated by California’s oil and gas industry, even though they only account for 44% of total facilities surveyed. While oil and gas sources for these combustion, fugitive, and vented emissions likely co-emit TACs along with CO_2 and methane, TAC emissions were not quantified in this survey.

A study by SAGE Environmental Consulting (2019) measured fugitive methane and NMVOC (referred to as VOCs in the report) emissions from 39 upstream gas production facilities in California on a component level (e.g., valves, connectors, flanges, open-ended lines). The study's primary goal was to characterize fugitive emissions; composition of gas was not a priority. SAGE Environmental Consulting detected a total of 31 NMVOCs from 81 emission samples taken from various components in liquid and gas service at upstream gas facilities. Because the high flow rates of the sampling devices were higher than the fugitive emission rates from the components, it is likely that the samples contained a mixture of fugitive emissions and ambient air. Therefore, it is not possible to determine how much the fugitive emissions and ambient air contributed to the NMVOC concentrations in the samples. Detected NMVOCs are listed in **Table 4.3** and are provided for comparative purposes only.

An additional study by Lebel et al. (2020) measured methane emissions from abandoned oil and gas wells in California. Benzene was measured at a single unplugged well and was found to be below the detection limit of 6 micrograms per hour (µg/h). Additional testing and public disclosure of the composition of NMVOCs in emissions from upstream gas is needed to assess air pollution health risks and inform policy makers.

Table 4.2. Total California combustion, vented, and fugitive emissions by primary business type. Source: Table 3-2 and Table 3-3 in CARB (2013a).

Primary Business Type		Metric Tons			Metric Tons of CO_2e			Totals	
Type	**No. of Facilities**	**CO_2**	**CH_4**	**N_2O**	**Combustion**	**Vented**	**Fugitive**	**CO_2e**	**% of Total**
Onshore Crude Production	668	9,645,891	30,568	178	9,784,578	125,428	433,082	10,343,089	58%
Other	53	4,579,097	567	108	4,616,047	53	8,512	4,624,612	26%
Natural Gas Processing	17	913,595	6,090	6	879,601	24,102	139,698	1,043,400	6%
Onshore Natural Gas Production	703	205,336	16,247	4	218,910	117,835	210,879	547,624	3%
Crude Processing and Storage	42	370,666	1,719	2	346,952	15,940	44,347	407,239	2%
Natural Gas Storage	10	200,638	6,263	9	226,569	90,537	17,758	334,864	2%
PERP Equipment Owner	58	148,082	339	1	148,825	1,960	4,793	155,577	1%
Offshore Crude Production	16	101,807	1,772	4	104,272	16,708	19,138	140,118	1%
Crude Pipeline	65	71,625	829	3	72,515	0	17,306	89,821	1%
Totals:	**1,632**	**16,236,738**	**64,394**	**314**	**16,398,268**	**392,563**	**895,513**	**17,686,345**	**100%**

Other includes: Compressed natural gas (CNG) compression and marketing, cogeneration, combined heat and power, electricity generation, portable heating, water disposal, vapor recovery services.

Table 4.3. Emission rates of VOCs identified in upstream gas systems in California (n=81 samples). Sources of VOCs cannot be determined due to ambient air mixing during sample collection. Emission rates are provided for comparison purposes only. Source: SAGE Environmental Consulting (2019).

VOC Name	CASRN	No. of Detections	Min (µg/hr)	5th Percentile (µg/hr)	Mean (µg/hr)	Median (µg/hr)	95th Percentile (µg/hr)	Max (µg/hr)	From gas service	From liquid service
1,2,4-Trimethylbenzene	95-63-6	3	0.81	0.99	5.33	2.59	11.60	12.60	Yes	
1,2-Dibromoethane	106-93-4	29	58.00	195.00	3,740.00	585.00	15,800.00	21,100.00		Yes
1,3,5-Trimethylbenzene	108-67-8-	2	5.16	5.32	6.80	6.80	8.27	8.44	Yes	
2-Hexanone	591-78-6	1	124.00	124.00	124.00	124.00	124.00	124.00	Yes	
4-Ethyltoluene	622-96-8	3	2.71	2.71	8.20	6.77	14.70	15.60	Yes	
Acetone	67-64-1	4	0.78	0.78	2.94	1.07	7.72	8.88	Yes	
Benzene	71-43-2	16	0.37	0.37	6.63	1.14	25.80	80.60	Yes	
Carbon disulfide	75-15-0	2	0.32	0.32	0.32	0.32	0.33	0.33	Yes	
Chlorobenzene	108-90-7	1	45.60	45.60	45.60	45.60	45.60	45.60	Yes	
Chloroform	67-66-3	1	34.00	34.00	34.00	34.00	34.00	34.00		Yes
Cyclohexane	110-82-7	21	0.44	0.51	25.00	2.47	174.00	227.00	Yes	
Ethanol	64-17-5	13	0.83	0.90	2.27	1.48	6.31	8.98	Yes	
Ethyl Acetate	141-78-6	2	0.49	0.50	0.59	0.59	0.67	0.68	Yes	
Ethylbenzene	100-41-4	5	0.68	0.95	5.32	2.22	15.00	17.80	Yes	
Heptane	142-82-5	18	0.63	0.77	12.50	1.51	77.80	89.30	Yes	
Hexane	110-54-3	23	0.37	0.72	29.70	2.49	77.20	404.00	Yes	
Isopropyl alcohol	67-63-0	8	0.23	0.28	3.11	0.67	13.20	19.20	Yes	
Methyl Isobutyl Ketone	108-10-1	4	0.38	0.43	7.15	3.17	19.40	21.90	Yes	Yes
Methylene chloride	75-09-2	8	1.72	1.76	2.91	2.35	5.99	7.73		Yes
Methyl-t-butyl ether	1634-04-4	8	0.41	0.41	0.61	0.46	1.29	1.69		Yes
Propylene	115-07-1	8	0.51	0.53	0.90	0.62	2.17	2.98		Yes
t-Amyl Methyl Ether	994-05-8	25	0.35	0.39	885.00	20.90	3,730.00	3,780.00		Yes
Tetrahydrofuran	109-99-9	37	0.14	0.16	935.00	1.36	5,730.00	5,820.00		Yes
Toluene	108-88-3	32	0.34	0.40	7.90	2.31	46.60	64.80	Yes	Yes
TPH Gasoline (C4-C12)	N/A	12	154.00	167.00	3,120.00	542.00	15,100.00	16,200.00	Yes	
trans-1,2-Dichloroethene	156-60-5	10	0.71	0.74	2.64	2.11	7.51	11.80		Yes
trans-1,3-Dichloropropene	10061-02-6	20	0.82	0.98	596.00	111.00	1,910.00	1,940.00		Yes
Trichloroethene (TCE)	79-01-6	34	0.92	1.18	4,680.00	24.70	26,400.00	26,800.00	Yes	Yes
Trichlorofluoromethane	75-69-4	6	1.33	1.37	2.77	1.60	5.47	5.64		Yes
Vinyl chloride	75-01-4	31	0.26	0.28	76.00	0.95	375.00	380.00		Yes
Xylenes (total)	1330-20-7	25	0.46	0.51	7.65	3.59	29.90	57.30	Yes	Yes

4.2.1.3 Air quality and permitting in California's oil and gas basins

The state of California relies on 35 local air districts to control air pollution emissions from stationary sources, including upstream OGD (CalGEM, 2015). Referred to as Air Quality Management Districts (AQMD) or Air Pollution Control Districts (APCD), these governing authorities process and approve permits for stationary sources and regulate the cumulative air quality impact to the region through air quality management plans or clean air plans (CalGEM, 2015).

Of the 35 air districts in the state, 22 intersect with active oil and gas fields, and 16 districts have one or more active or new oil and gas wells within their jurisdiction (**Figure 4.1**; **Figure 4.2**) (CalGEM, 2021b; CARB, 2019a). The highest number of wells are located in SJVAPCD and SCAQMD regions (**Figure 4.1**) (CalGEM, 2021b; CARB, 2019a). When considering only active and new well permits, we found that only 16 air districts had at least one active or new well intersect with its boundaries (as of March 1, 2021) (**Figure 4.2**). Again, SJVAPCD and SCAQMD had the largest number of active and new oil and gas wells.

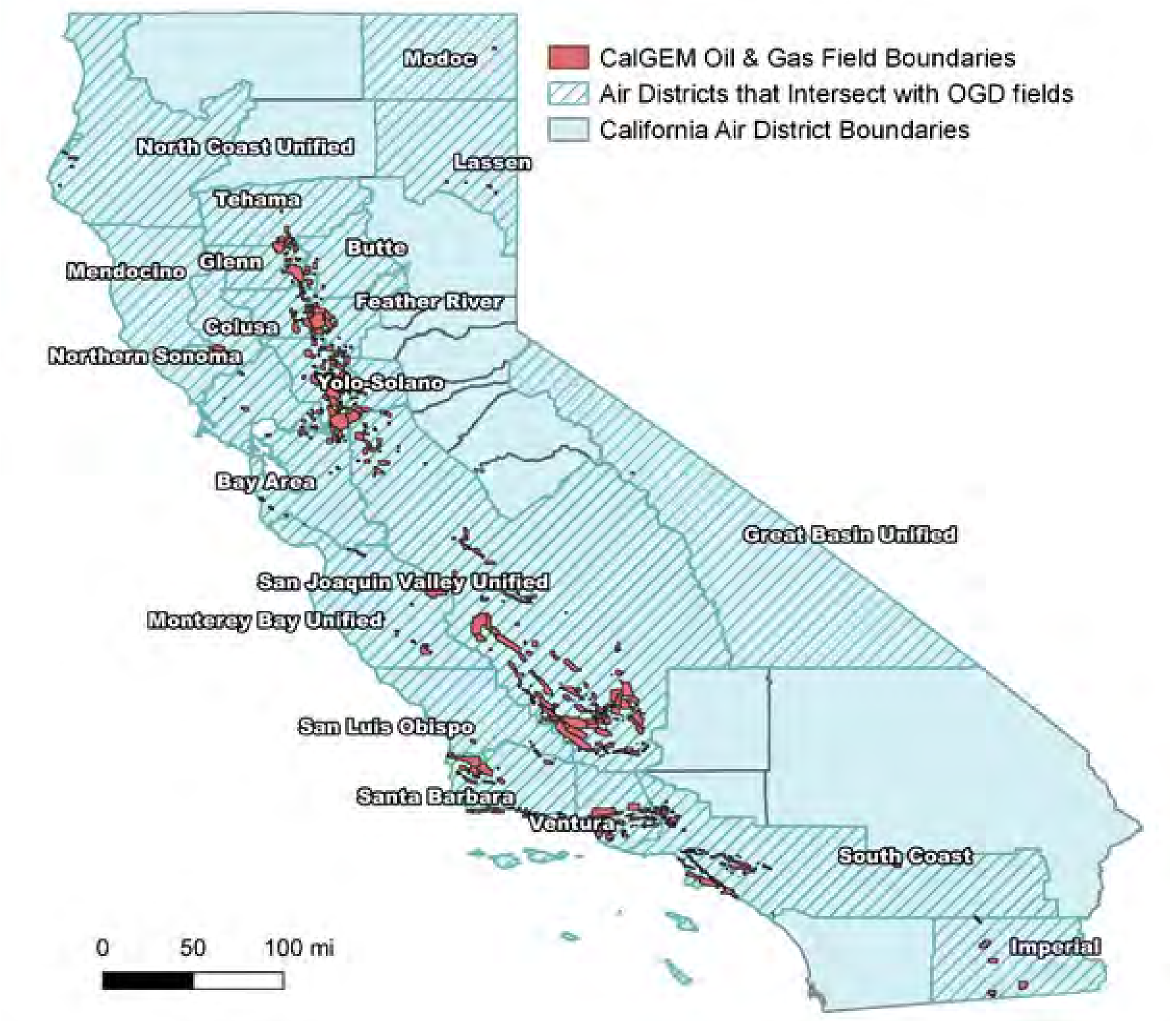

Figure 4.1. Air Districts that intersect with oil and gas fields in California (22 total). Sources: CalGEM (2021b); CARB (2019a).

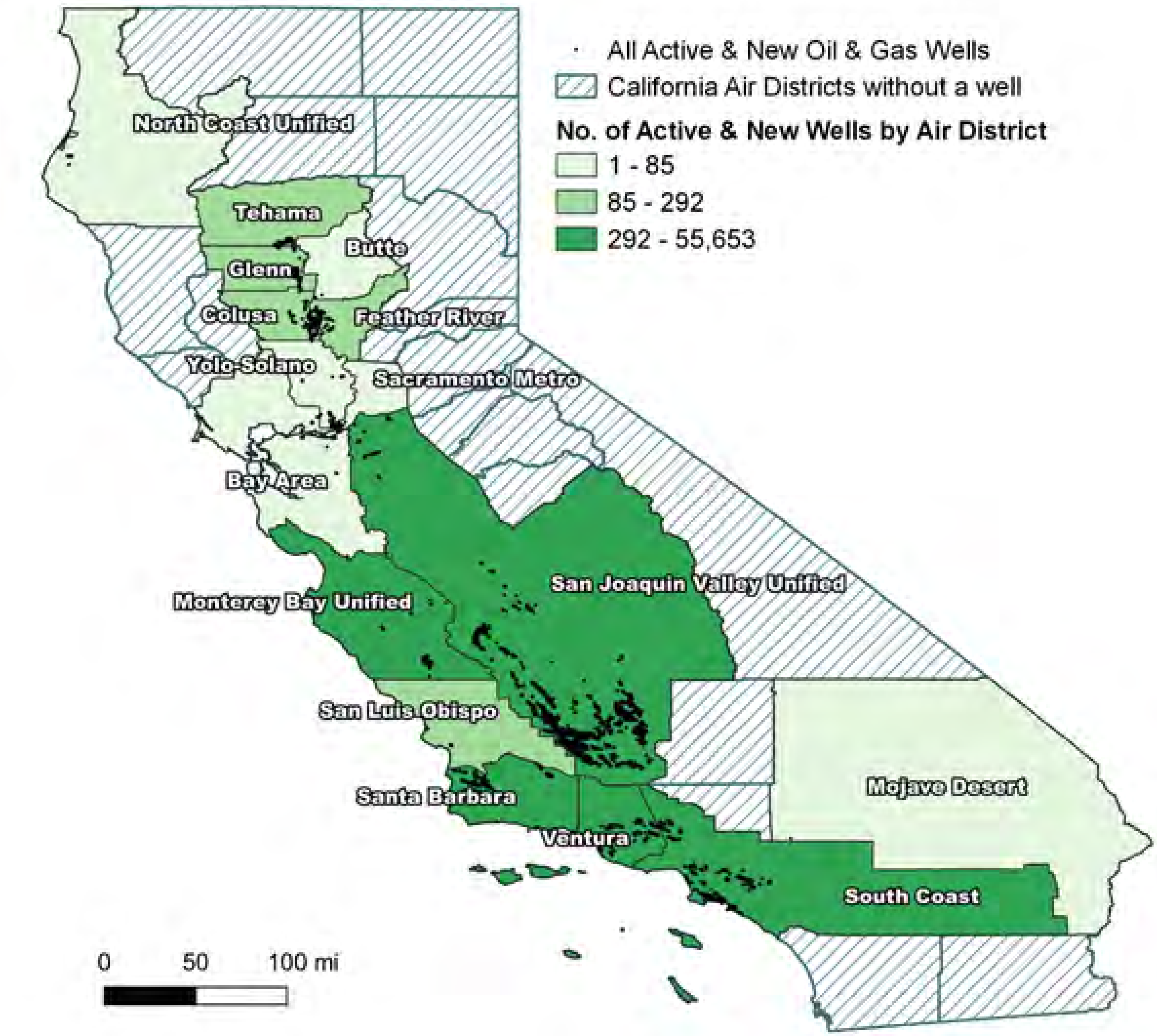

Figure 4.2. Air Districts that have a new or active oil and gas well within their jurisdiction. Sixteen districts have one or more new or active oil and gas wells as of March 1, 2021. Striped districts have zero new or active oil and gas wells. Sources: CalGEM (2021b); CARB (2019a).

Top upstream OGD regions in California

The San Joaquin Valley and South Coast Air Basins encompass the largest oil and gas producing regions in California. The majority of hydraulic fracturing operations in California occurs in the San Joaquin Valley Air Basin (EIA, 2021; Shonkoff & Gautier, 2015) . More generally, current oil production in both regions accounts for a significant portion of California's overall production volume, accounting for approximately 80% of all oil produced since 2015 (Brandt et al., 2015; CalGEM, 2021a). CalGEM annual production volumes indicate 88.1% of the total oil produced in the state from 2015 to the beginning of 2021 can be attributed to upstream oil and gas activity in just 20 fields (CalGEM, 2021a). Twelve of these 20 oil and gas fields (70% of oil produced since 2015) are located in the San Joaquin Valley and Kern County, four are located in the South Coast Air Basin (Wilmington, Huntington Beach, Long Beach & Inglewood) (10% of oil production), and the remaining three are located outside of these two regions (CalGEM, 2021a).

In 2015 and pursuant to Senate Bill 4, (2013, Pavley) the California Council on Science and Technology (CCST) published a multi-volume, multi-chapter assessment on well stimulation activities in California. The report found that, from 2012 to 2013, 96% of hydraulic fracturing activities in California were located in the San Joaquin Basin, with 85% of activity occurring in just four fields: South and North Belridge, Lost Hills, and Elk Hills (CCST, 2015). A smaller amount of hydraulic fracturing activities occur in the Los Angeles-South Coast Air Basin (CCST, 2015). Approximately 25% of all production in the Los Angeles Basin is associated with hydraulic fracturing techniques (CCST, 2015).

The South Coast and San Joaquin Valley Air Basins also have some of the worst air quality in California (Brandt et al., 2015; CARB, 2021a). As of March 1, 2021, both air basins are not in attainment for ozone and fine particulate matter ($PM_{2.5}$) when compared to the National Ambient Air Quality Standards (NAAQS) and California Ambient Air Quality Standards (CAAQS), and not in attainment for coarse particulate matter (PM_{10}) when compared to state CAAQS (SCAQMD, 2018a; SJVAPCD, 2012). Attainment with national standards for each region is determined by comparing the "design value" to the established NAAQS (US EPA, 2016a). For ozone pollution, the design value represents a three-year average of the fourth highest annual daily maximum 8-hour ozone concentration among the area's regional monitors (US EPA, 2016a, 2021)**.** For $PM_{2.5}$ pollution, the design value is the annual mean $PM_{2.5}$ concentration averaged over three consecutive years, and represents the highest value among monitors with valid values (US EPA, 2016a). Depending on the magnitude to which the design value exceeds the established standard, areas of nonattainment are further broken down into six categories ranging from "marginal" to "extreme" (CARB, 2021a)**.**

The designations by air basin for ozone and $PM_{2.5}$ attainment status are shown in **Figure 4.3** and **Figure 4.4**, respectively. Ozone pollution in the San Joaquin Valley and South Coast region are both in "extreme" nonattainment with national standards, meaning their design values are 0.163 ppm or greater — more than double the current 8-hour standard of 0.07 ppm (US EPA, 2016b). Similarly, $PM_{2.5}$ pollution is classified as "serious" in the Los Angeles-South Coast Air Basin and "moderate" in the San Joaquin Valley, indicating large to moderate excesses above the national standard for $PM_{2.5}$ in both basins.

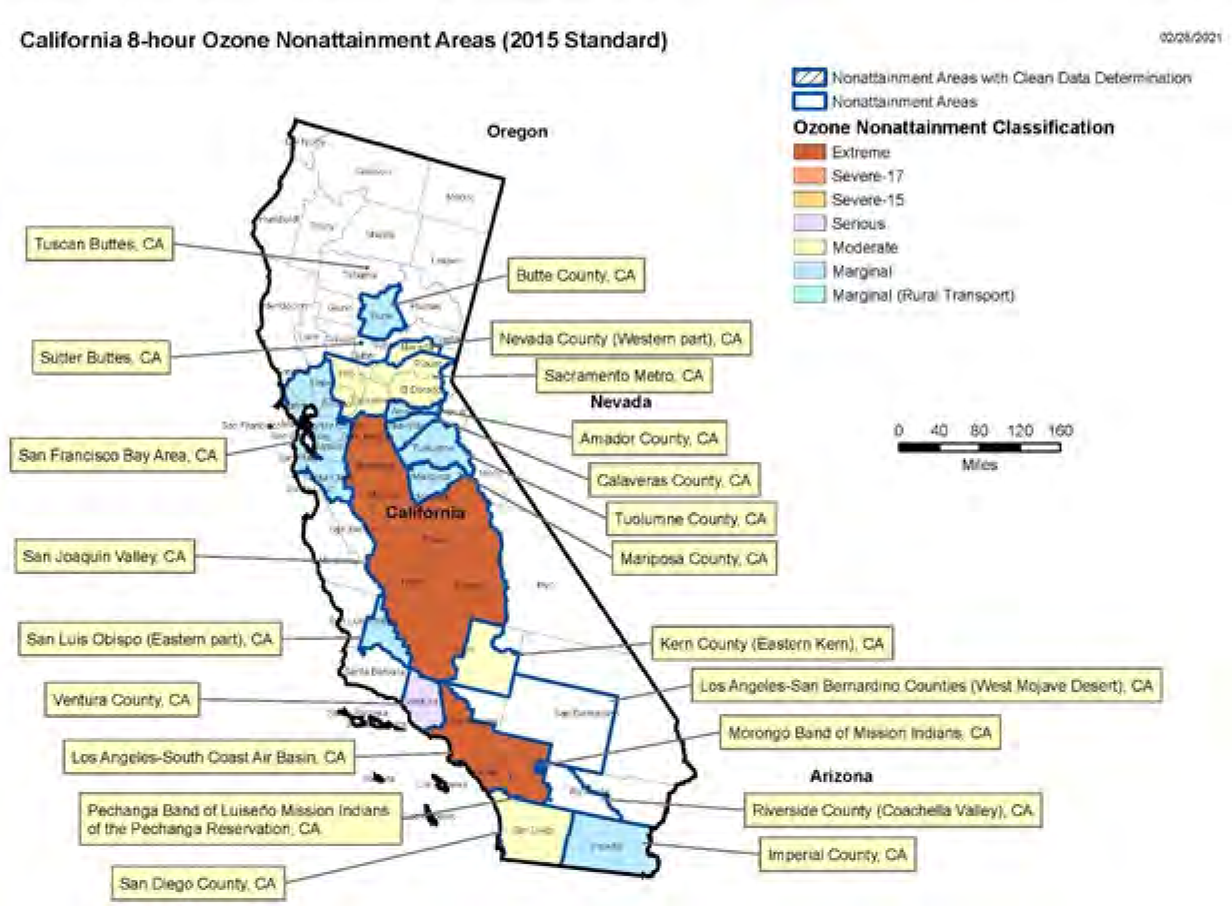

Figure 4.3. Air basin designation of 2015 8-hour ozone standard. Source: US EPA (2016c).

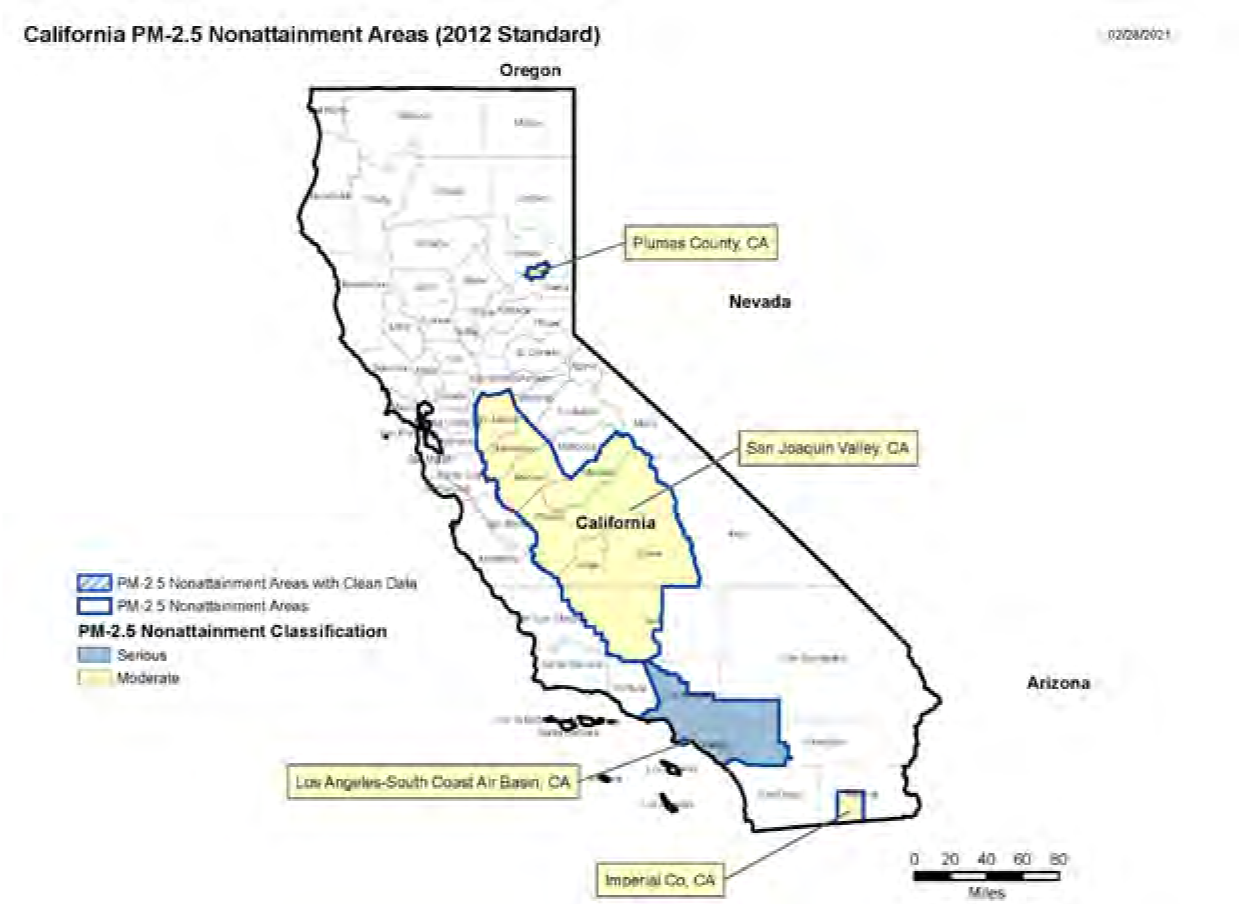

Figure 4.4. Air basin designation of 2012 $PM_{2.5}$ standard. Source: US EPA (2016c).

Chapter 3 of the CCST report identified the major contributors to air pollution in the Los Angeles-South Coast and San Joaquin Valley Air Basins (Brandt et al., 2015). This study found that many sources are responsible for the poor air quality seen in both the South Coast and San Joaquin Valley regions, including but not limited to emissions from upstream OGD, other industrial sources, agriculture, residences and businesses, and transportation (Brandt et al., 2015). Upstream OGD in the San Joaquin Valley contributes significantly more to the region's overall air pollutant burden as compared to the South Coast region (Brandt et al., 2015). In the Los Angeles-South Coast area, upstream OGD is only a small portion of the District's regional emissions, accounting for less than 1% of all pollutants (Brandt et al., 2015). In the San Joaquin Valley, however, upstream OGD accounts for a significant portion of H_2S emissions (70%) and SO_x emissions (31%), and is responsible for approximately 8% of the District's ROG emissions and 4% of emissions of NO_x (Brandt et al., 2015). This finding is significant, as photochemical oxidation reactions between ROGs and NO_x contribute to the formation of ground-level ozone (US EPA OAR, 2014). Additionally, upstream OGD in the San Joaquin Valley contributes to significant fractions of some TAC species, including BTEX ((Brandt et al., 2015, see Figure 3.3-10).

Upstream OGD plays a significant role in influencing the air quality of San Joaquin Valley. This finding is especially important when considering the large population located near upstream OGD in the San Joaquin Valley. Shonkoff et al. (2015b) found that approximately 500,000 people live within 1 mi (1,609 m) of a stimulated well, and this number significantly increases when considering any type of upstream OGD**.** Results from our proximity analysis (presented in Chapter 7) indicate that over 3 million people live within 1 kilometer (3,281 ft) of an oil and gas well in California. Similarly, while upstream OGD does not contribute to a large portion of emissions in the South Coast Air Basin, the region's population density is more than 10 times greater than in the San Joaquin Valley, with residents often located near upstream oil and gas activity (Brandt et al., 2015).

In Chapter 4 of the CCST report, Shonkoff & Gautier (2015) conducted a bottom-up inventory analysis of the various sources that contribute to the harmful air pollution levels seen in the South Coast Air Basin. Results from this assessment found stationary sources from upstream OGD to emit 2,361 kilograms per year (kg/yr) of benzene representing a significant portion (9.6%) of benzene emissions from stationary sources (Shonkoff & Gautier, 2015). Similarly, this analysis found upstream oil and gas facilities to emit 5,846 kg/yr of formaldehyde, accounting for 3.8% of formaldehyde emissions from stationary sources. However, when accounting for all sources of emissions (including mobile) within the South Coast Air Basin, the authors find that the upstream oil and gas sector is responsible for <1% of all source emissions of benzene and formaldehyde. These results suggest that while emissions from upstream OGD may not significantly impact regional air quality within the South Coast Air Basin, local emission peaks in close proximity to upstream OGD sites may pose a risk to those residents and other sensitive receptors located nearby.

Shonkoff & Gautier (2015) also performed a proximity analysis in the Los Angeles Basin. They considered production wells that were active in 2013 or 2014, and estimated populations within buffers of 100 to 2,000 m (328 to 6,562 ft) from these active wells. This assessment found that approximately 12% of the South Coast Air Basin population (~2.3 million people) live within 2,000 m (6,562 ft) of an active oil and gas well (Shonkoff & Gautier, 2015). Therefore, upstream OGD also presents a significant air pollution hazard for communities in the South Coast Air Basin given that proximity to these activities increases exposure to TACs (Brandt et al., 2015; Shonkoff & Gautier, 2015).

Fann et al. (2018) estimated the number of air pollution-related deaths and adverse health symptoms attributable to the oil and gas industry in the United States.[2] Annual attributable mean $PM_{2.5}$ concentrations from oil and gas activities ranged from 5.27 µg/m^3 to <0.001 µg/m^3, with Alabama, Colorado, Illinois, Louisiana, North Dakota, Ohio, Oklahoma, Pennsylvania, Texas, and Wyoming experiencing the largest $PM_{2.5}$ concentrations (Fann et al. (2018). Similarly, the authors found average 8-hour ozone concentrations to range from 8.12 parts per billion (ppb) to 0.003 ppb, with Alabama, Louisiana, Nebraska, Oklahoma, Texas, and West Virginia experiencing the

[2] This study included oil and gas sources associated with production and transportation of oil and natural gas and distribution of natural gas but excluded refineries and the distribution of refined products (Fann et al., 2018).

greatest summer-season ozone concentrations from the oil and gas sector. The $PM_{2.5}$- and ozone-related excess mortality burden was greatest in Texas, Pennsylvania, Ohio, Oklahoma, Illinois, California, Michigan, Colorado, Indiana, and Louisiana. In 2025 in California, an estimated 59 deaths will be attributable to $PM_{2.5}$ emissions from the oil and gas sector, as well as an additional 14 deaths attributable to ozone associated to upstream oil and gas production (**Table 4.4**) (Fann et al., 2018).

Table 4.4. Estimated total and selected state $PM_{2.5}$- and ozone-related premature deaths attributable to emissions from the oil and gas sector in 2025. Source: Fann et al. (2018).

	Estimated numbers of premature deaths (95% confidence interval)[b]			
State[a]	**Attributable to $PM_{2.5}$**	**Attributable to ozone**	**Total deaths attributable to $PM_{2.5}$ and ozone**	**Total deaths per 100,000 people**
Texas	130 (88–170)	130 (70–190)	260 (160–370)	1.4
Pennsylvania	85 (57–110)	55 (30–80)	140 (87–190)	1.6
Ohio	65 (44–86)	48 (26–70)	110 (69–160)	1.5
Oklahoma	48 (32–63)	55 (29–81)	100 (62–140)	4.1
Illinois	55 (37–73)	38 (20–55)	92 (57–130)	1.1
California	59 (40–77)	14 (7.4–20)	72 (47–97)	0.27
Michigan	39 (26–52)	32 (17–47)	71 (44–98)	1.1
Colorado	37 (25–49)	34 (18–49)	70 (43–98)	1.9
Indiana	38 (26–50)	29 (15–42)	66 (41–92)	1.6
Louisiana	34 (23–45)	28 (15–40)	61 (38–85)	2
National total	1,000 (670–1,300)	970 (520–1,400)	1,900 (1,100–2,700)	0.9

[a] These states comprise the largest health impacts for the sector. States listed by descending order of total $PM_{2.5}$ and ozone-attributable deaths.
[b] All values rounded to two significant figures.

4.2.2. Review of source, exposure, and health risk assessment studies

In this section, we review studies that assess upstream OGD as a source of air pollution, as well as studies that assess exposures to and health risks from air pollutants attributed to upstream OGD. Our review focuses on peer-reviewed journal publications, government reports, and white papers commissioned by government agencies. The studies include air monitoring or modeling approaches to measure or estimate methane and associated health-damaging air pollutant concentrations from upstream OGD. Additionally, some of these sources place findings in the context of human health, for example, by comparing observed pollutant concentrations to air quality standards (e.g., NAAQS) or by estimating cancer and/or non-cancer health risk. Studies that rely on emissions inventories or are focused solely on methane emissions without quantification or estimation of TAC, CAP, and/or NMVOC concentrations were not included in this review.

Relevant sources were compiled using the PSE Repository for Oil and Gas Energy Research (ROGER) and California government agency websites (PSE Healthy Energy, 2020). In addition to California, we also summarize the results of peer-reviewed studies conducted outside the state, including assessments done in Colorado, Pennsylvania, Texas, Utah, and other states with upstream OGD. While these studies are not directly applicable to the California context, they provide useful insight into the air pollution and resultant health impacts associated with exposure to oil and gas at various distances.

4.2.2.1 Source assessment studies conducted in California

The primary focus of this section is to review studies that assess upstream OGD as a source of air pollutants (e.g., methane, CAPs, VOCs, TACs) using ambient air sampling, tracer, and modelling approaches. Studies that rely on emissions inventories or are focused solely on methane emissions were not included in this review.

Four peer-reviewed studies included air monitoring focused on upstream OGD in California (Collier-Oxandale et al., 2020; Gonzalez et al., 2022; Johnston et al., 2021; Okorn et al., 2021). Three studies were conducted in South Los Angeles at sites near oil and gas facilities. This region is of particular interest given its unique urban setting, high oil and gas activity, and high population density. In the Los Angeles Basin, about 1.7 million residents live within 1 mi (1,609 m) of an active oil and gas well (Collier-Oxandale et al., 2020; Okorn et al., 2021). Some 70% of active oil and gas wells are within 500 m (1,640 ft) of a residence, school, or hospital in Los Angeles, including over 500,000 residents (Okorn et al., 2021). Results from each study are summarized below in chronological order.

Collier-Oxandale et al. (2020) evaluated upstream OGD as a source of air pollutants in the Los Angeles region of California. The authors deployed low-cost device systems equipped with metal oxide VOC sensors to measure concentrations of methane and total non-methane hydrocarbons near upstream oil and gas activity. Methane and non-methane hydrocarbons are released during production and processing activities at oil and gas facilities, and are of highest concern at these sites (Allen et al., 2013).

Fifteen devices were deployed for an 8-week period at sites surrounding highways and oil and gas extraction activities occurring at a multi-well site within the West Adams and University Park communities in South Los Angeles.

The surrounding community was specifically interested in pollutant concentrations at two sampling sites (E1 and E2) <50 m (<164 ft), one east and one west of the oil and gas extraction site of interest. Results at these two sites suggest that the oil and gas extraction site is one plausible source of NMVOC (which include non-methane hydrocarbon) emissions. The authors incorporated CO_2 and CO concentration data over the same period, the results of which suggest that the short-term increases in methane and non-methane hydrocarbon observed over background levels are likely the result of volatilized vented (intentional release) emissions from the extraction site of interest, and not from a combustion source such as vehicle emissions from the nearby highway and surrounding major roadways (Collier-Oxandale et al., 2020). NMHCs include a variety of odor causing aromatic compounds, including BTEX and polycyclic aromatic hydrocarbons (PAHs). Some of the increases in methane and non-methane hydrocarbon concentrations observed at the two sites <50 m east and west of the extraction site correspond with concerns from the community regarding odors and/or heavy activity occurring at the extraction facility. **Figure 4.5** highlights how emissions of CO_2 and non-methane hydrocarbons correspond to odor and noise complaints as well as reports of heavy activity at the oil and gas extraction site.

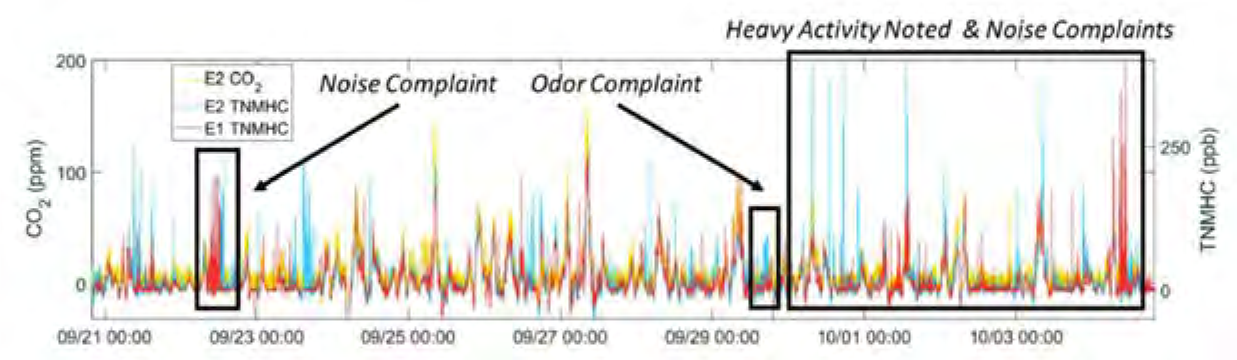

Figure 4.5. CO_2 and non-methane hydrocarbon emissions at Sites E1 and E2, annotated with noise and odor complaints as well as observations by residents of heavy activity at the drill site. Source: Figure 14, Collier-Oxandale et al. (2020).

While this study is limited in that it relies on low-cost monitoring tools, results suggest vehicle emissions are not the only source impacting the air quality of the West Adams and University Park communities. Results from Okorn et al. (2021) support these findings.

From 2016 to 2019, Okorn et al. (2021) deployed low-cost air sensors that measure methane, non-methane hydrocarbons, CO_2, and CO in three Los Angeles communities located near oil and gas facilities, with active operations occurring at sites 1 and 3 and no production occurring at site 2 (well activity ceased in 2013). All three facilities are located within 3 km (1.86 mi) of each other and draw from the Las Cienegas oil field (Okorn et al., 2021). At each site, anywhere from four to 11 devices were installed within 500 m (1,640 ft) of the facility. Two to 11 devices were deployed outside this 500 m radius: at a distance of 800 m to 8 km (2,624 ft to 26,247 ft) for Site 1; 4 km away (13,123 ft) for Site 2; and 800 m to 1 km (2,624 ft to 3,281 ft) for Site 3. The devices deployed outside the 500 m (1,640 ft) radius were used to estimate emissions from major roadways and to act as controls (Okorn et al., 2021, see Figure 2).

Results from this study demonstrate that methane levels varied based on proximity to an oil and gas facility (Okorn et al., 2021). Specifically, monitoring results show that methane levels are higher within 500 m (1,640 ft) of the three oil and gas facilities and near a gas pipeline, compared to concentrations farther away (**Figure 4.6**). The authors theorize this trend is likely a result of proximity to emission sources (Okorn et al., 2021). Significant methane concentrations were also found at Site 2, where wells have been idle since 2013, indicating that fugitive emissions of methane may still be released by oil and gas well sites long after active operations have stopped.

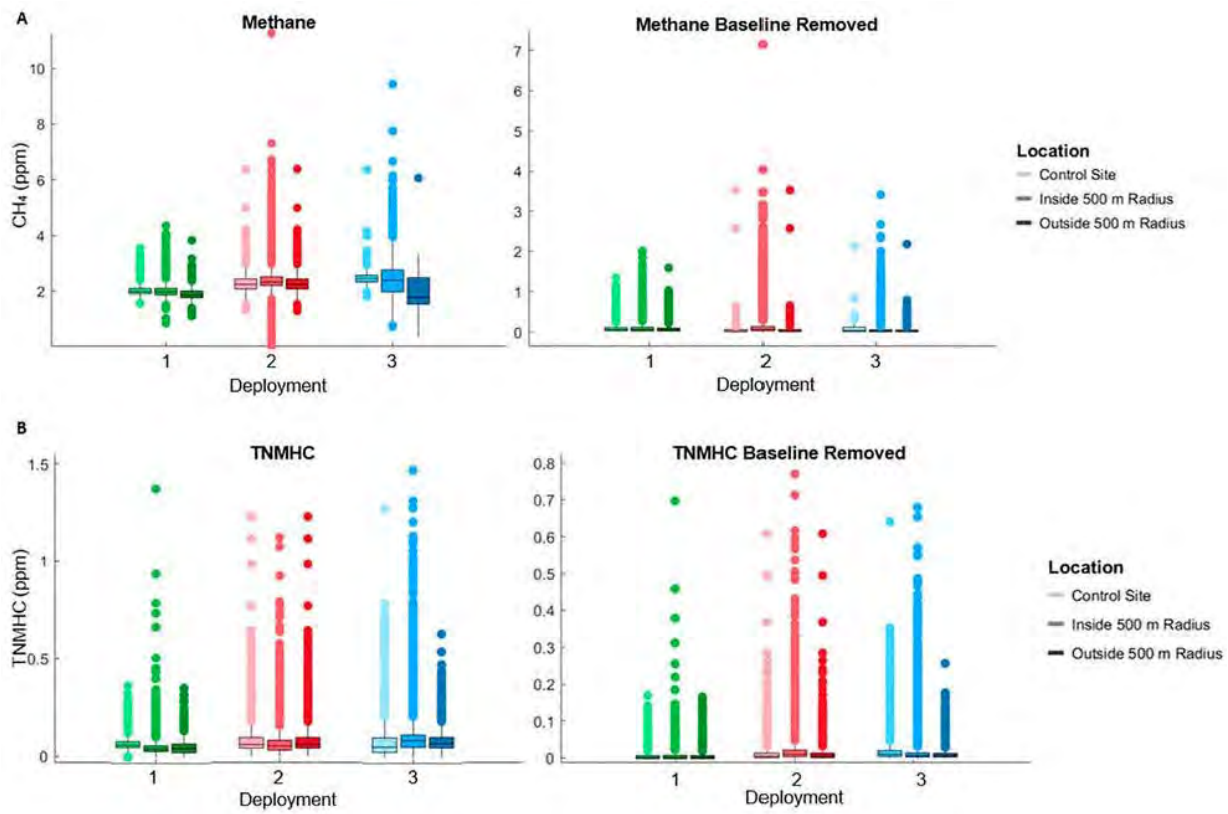

Figure 4.6. Methane and total non-methane hydrocarbon (TNMHC) concentrations at the control site, within 500 m (1,640 ft) of each facility, and outside the 500 m (1,640 ft) radius. Source: Figure 5, Okorn et al. (2021).

Unlike methane, which shows a clear and significant association with proximity to upstream oil and gas activity, total non-methane hydrocarbons results were less straightforward. Total non-methane hydrocarbon concentrations within the 500 m (1,640 ft) radius were similar to concentrations found outside this radius (control sites and near major freeways), with modest differences seen at Sites 1 and 2. Total non-methane hydrocarbons levels were found to be significantly associated with proximity to freeways for Sites 1 and 3, suggesting that traffic is a significant source of non-methane hydrocarbons in these communities. However, total non-methane hydrocarbons monitoring results show that short-term, episodic emissions spikes tended to be higher at locations near an oil and gas facility compared to variances seen outside of the 500 m (1,640 ft) radius, suggesting these events may be associated with specific oil and gas activities conducted on-site (Okorn et al., 2021).

Johnston et al. (2021) evaluated the methane, NMVOC, and TAC concentrations adjacent to an oil and gas production site in Los Angeles. Oil and gas production facilities, have periods of active production as well as idle periods, emissions of which greatly differ depending on the phase. Johnston et al. (2021) found average concentrations of methane, total NMVOC, BTEX, styrene, n-hexane, n-pentane, ethane, and propane to decrease once production activities idled.

Specifically, the authors observed a 28%, 32%, and 69% decrease in toluene, benzene, and n-hexane concentrations, respectively, after production at the site idled. Results from positive matrix factorization (PMF) modeling suggest that oil and gas drilling during the active phase contributed 23.7% of the total NMVOCs measured, while the idle period only contributes 0.6% (Johnston et al., 2021). While TAC concentrations at the fenceline were below state-designated acute Reference Exposure Levels (RELs), they were higher than background concentrations taken by CARB (2013b) and SCAQMD (Final Multiple Air Toxics Exposure Study (MATES) IV, 2015) for the area, suggesting a local emissions source. RELs are Health Guidance Values from California Office of Environmental Health Hazard Assessment that are used to determine the amount of a chemical in air that does not cause a noncancer health effect, such as asthma.

Gonzalez et al. (2022) investigated whether drilling new wells or increasing production volume at active wells in California resulted in emissions of $PM_{2.5}$, CO, nitrogen dioxide (NO_2), ozone, or NMVOCs (referred to as VOCs in the study). To isolate the effect of oil and gas activities on air pollutant concentrations, the authors used daily variation in wind direction as an instrumental variable and used fixed effects regression to control for unobserved time-trending factors and time-invariant geographic factors. This allowed the authors to control for geographic, meteorological, seasonal, and time trending factors and compare monitors to themselves, i.e., to compare concentrations of pollutants on days when the wind was blowing from nearby oil and gas operations to days when there were no oil and gas activities.

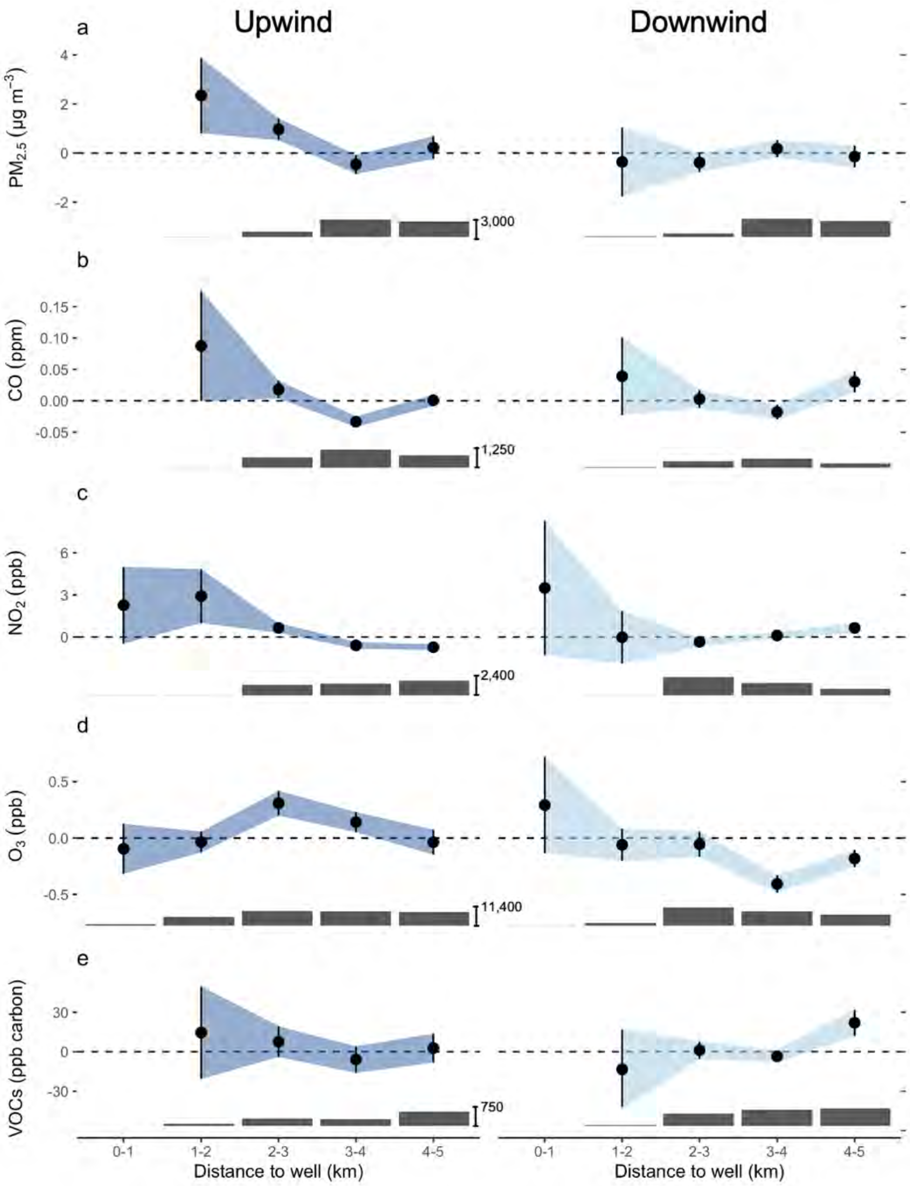

Figure 4.7. Point estimates (95% CIs) for the marginal effect of one additional preproduction well upwind (left column) and downwind (right column) of the monitor. The bar plots show the number of monitor-days with exposure to at least one preproduction well within each distance bin. Source: Figure 3, Gonzalez et al. (2022).

Results from the Gonzalez et al. (2022) study indicate that, on days when wells were being drilled upwind, there were significantly higher concentrations of $PM_{2.5}$, NO_2, NMVOCs, and ozone as far as 4 km (13,123 ft) from the wells (**Figure 4.7**). While there were higher concentrations up to 4 km (13,123 ft) from the wells, the amount to which concentrations were elevated do appear to decrease with increasing distance from the well. Daily concentrations of $PM_{2.5}$ increased by 2.35 µg/m^3 (95% confidence interval [CI]: 0.81, 3.89) for each additional well drilled upwind of a monitor ~2 km (~6,562 ft) away. Daily concentrations of ozone (O_3) increased by 0.31 (standard error [SE]: 0.06) parts per billion (ppb) for wells within 2–3 km (6,562–9,843 ft); and nitrogen dioxide (NO_2) increased by 2.27 (SE: 1.40) ppb for wells within 1 km (3,281 ft). For each additional active well upwind of the monitor, these authors also found 1.93 (SE: 0.43) µg/m^3 of $PM_{2.5}$, 0.62 (SE: 0.12) ppb of NO_2, and 0.04 (SE: 0.02) ppb carbon (C) of NMVOCs. (**Figure 4.8**). The daily concentrations of $PM_{2.5}$ increased 1.93 µg/m^3 (95% CI: 1.08, 2.78) for each additional 100 barrels of oil equivalent (BOE) produced within 1 km (3,281 ft) of monitors; 100 BOE is approximately the median volume of oil and gas production at active wells in California. In placebo tests, the authors assessed exposure to wells *downwind* of the air monitors and observed no effect on air pollutant concentrations. Notably, the methods employed by Gonzalez et al. (2022) to estimate air pollutant concentrations in relation to distance from oil and gas wells are similar to methods employed in many epidemiological studies that measure exposure using residential proximity wells.

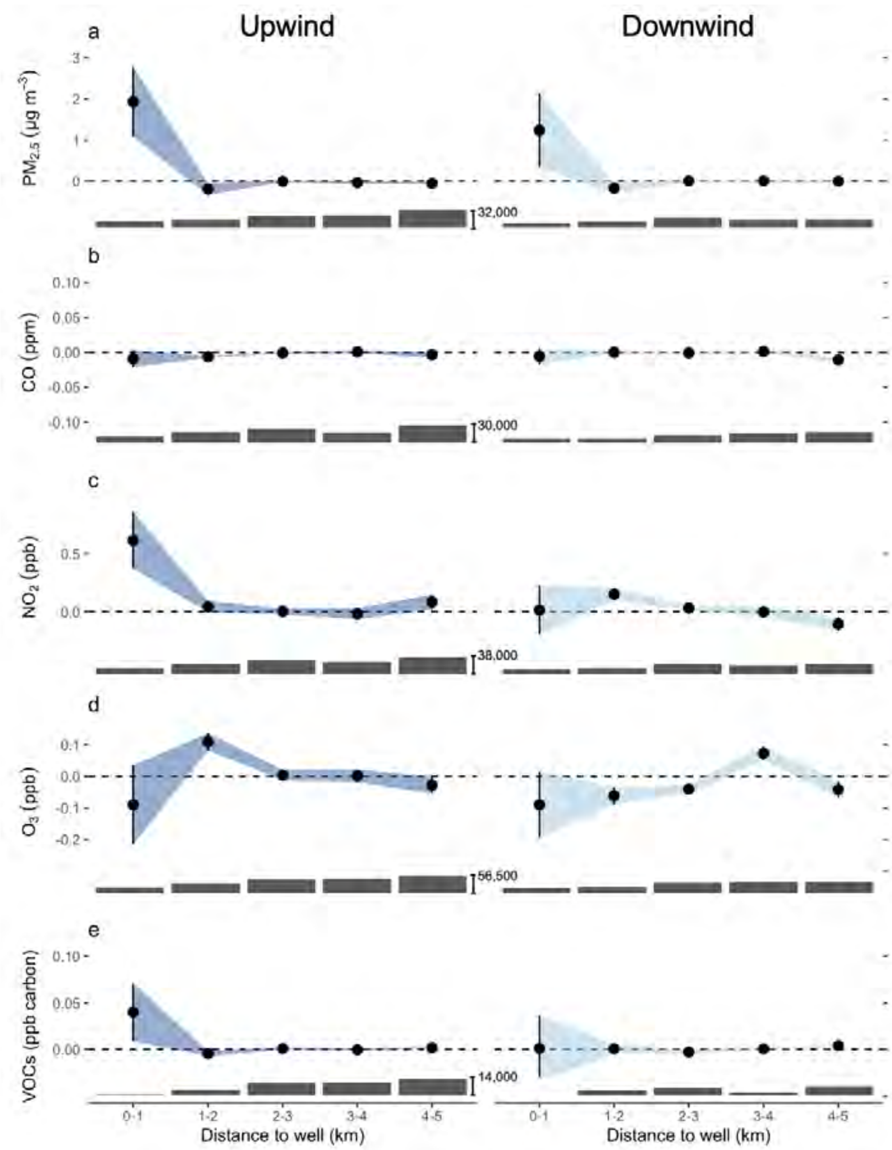

Figure 4.8. Point estimates (95% CIs) for the marginal effect of 100 additional barrels of oil equivalent (BOE) of daily production volume, for wells upwind (left column) and downwind (right column) of the monitor. The bar plots show the number of monitor-days with exposure at least 1 BOE of daily production volume within each distance bin. Note that more monitor-days had exposure to production volume than preproduction wells. Source: Figure 4, Gonzalez et al. (2022).

We also reviewed five government-sponsored reports that include air monitoring focused on upstream OGD in California (LACDPH, 2018; Mellqvist et al., 2017, 2019; SCAQMD, 2015a, 2015b). Four of the studies focused on emissions in the South Coast Air Basin (LACDPH, 2018; Mellqvist et al., 2017; SCAQMD, 2015a, 2015b), and one was conducted in the San Joaquin Valley (Mellqvist et al., 2019).

In 2015, Fluxsense Inc. conducted a five week sampling campaign to characterize emissions from oil wells, oil treatment facilities, and small tank farms (Mellqvist et al., 2017). This study took measurements from 900 surveys related to emissions from the oil and gas sector, completed between September–November 2015 (Mellqvist et al., 2017). Emission fluxes (kg/hr) of alkanes (a subset of non-methane hydrocarbons), BTEX, and methane were estimated by source type using a variety of methods and instruments. Results from all locations sampled were 1,318 kg/hr of alkanes, 68 kg/hr of BTEX (12 kg/hr for benzene) and 636 kg/hr of methane (Mellqvist et al., 2017). These totals are based on emissions measurements from various oil and gas facilities, including oil and gas well sites, and tank farms, terminals, and depots, among others. **Figure 4.9** shows the contribution of total alkane emission fluxes from stationary sources by source category.

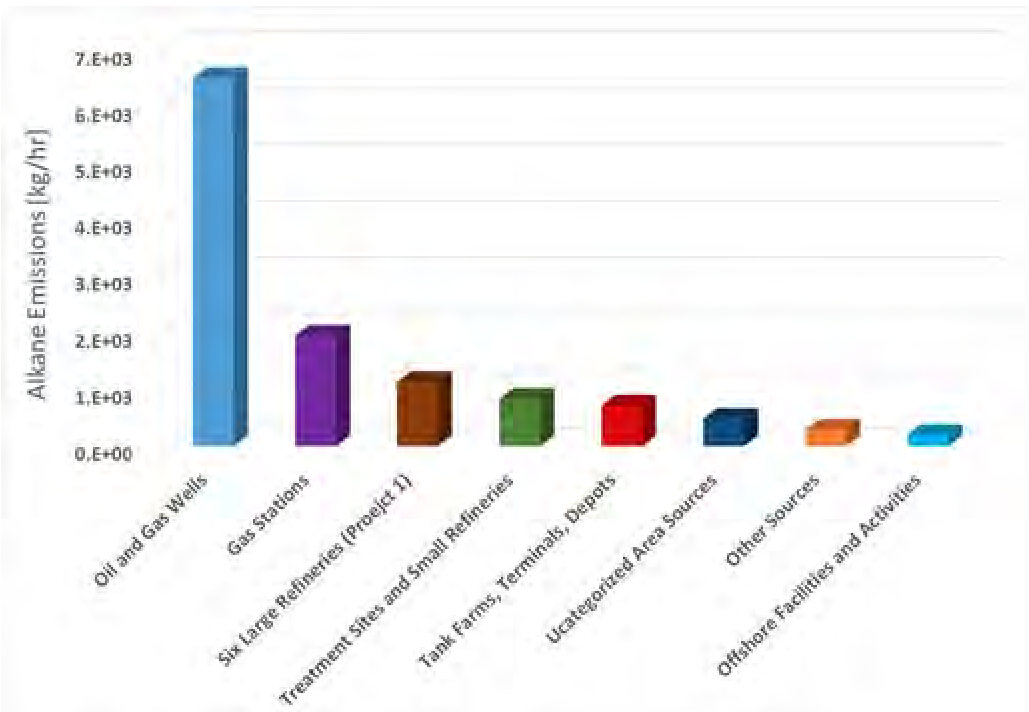

Figure 4.9. Contribution of total alkane emission fluxes from stationary sources by category. Source: Figure ES-1, Mellqvist et al. (2017).

As demonstrated in **Figure 4.9**, the study found 85% of total alkane emissions surveyed can be attributed to releases from oil and gas wells, gas stations, and treatment facilities and small refineries, with oil and gas wells contributing more than half of the estimated total (Mellqvist et al., 2017). The authors note that emissions from small point sources such as oil and gas wells are especially concerning when considering the large population residing in close proximity to these source types in the South Coast Air Basin and the potential adverse health impacts associated with such elevated exposures (Mellqvist et al., 2017).

Additionally, in 2022, FluxSense Inc. conducted another assessment, evaluating the emissions from upstream OGD in the San Joaquin Valley and South Coast (Mellqvist et al., 2022). Emissions of NMVOCs, methane and TACs from several of California's largest producing oil fields in Kern County were measured. A total of 6,100 kg/hr of alkanes and 10,300 kg/hr of methane were measured from 11 fields. NMVOC plumes were detected at all oil field fencelines; however, BTEX concentrations were measured above detection limit (low ppb) in only some of the fields. For field plumes with detectable BTEX concentrations, the ratio of BTEX mass fraction to alkane mass fraction was of the order of 5%. The ratio of benzene specifically was 1%. Some processing sites or facilities close to the fenceline had evident BTEX emissions reaching neighboring communities. Emissions of alkanes and methane from Inglewood Oil Field in Los Angeles County were 101 kg/hr alkanes and 121 kg/hr, respectively. BTEX emissions were 16 kg/hr, with benzene contributing 7.7 kg/hr. Plume dispersion measurements within the field campaigns showed that evening and nighttime plumes of TACs can be traced at measurable levels often kilometers away from an isolated source. Modeling of plume dispersion and contaminant concentrations were carried out for two sites in San Joaquin Valley and were validated with measurements. Although cross wind dispersion may be underestimated by the simulation, the results showed that plumes likely carry far into residential areas, and this was supported by measurements.

In addition to the 2017 and 2022 reports, Fluxsense Inc. also conducted a set of comparative measurements to characterize and quantify emissions of NMVOCs from a subset of small oil and gas sources in the South Coast region (SCAQMD, 2015a). Preliminary results found elevated levels of alkanes (~3,200 ppb) and benzene (21 ppb) downwind from a small oil treatment facility. Instantaneous elevated concentrations of benzene were detected near three oil well sites on multiple days, and follow-up inspections confirmed the presence of leaks as the source of these elevated benzene levels (SCAQMD, 2015a). Main findings from this study suggest (1) small sources like oil wells likely contribute substantially to total NMVOC emissions from stationary sources, and (2) oil wells may contribute to total NMVOC emissions more than previously thought (SCAQMD, 2015a).

The SCAQMD's Multiple Air Toxics Exposure Study IV (MATES IV), released in 2015, estimated the emissions contribution of various oil and gas processes, including upstream OGD activities such as oil production, in the South Coast Air Basin (SCAQMD, 2015b). A comparison of emissions estimates from major source categories found OGD (i.e., upstream activities) in the South Coast Air Basin to contribute significantly to total emissions of TACs and NMVOCs from oil and gas sources (e.g., midstream activities like refining) (SCAQMD, 2012). Emissions from upstream oil and gas activities (e.g., production) accounted for 17.4% (~57 lbs/day) of benzene emissions; 7.2% of formaldehyde (~70.6 lbs/day); 100% of diesel particulate matter (DPM) (~25 lbs/day); and 100% of fine DPM (~24 lbs/day) emitted by oil and gas upstream and midstream sources (e.g., petroleum production, refining, and marketing) (**Table 4.5**). Similarly, upstream oil and gas sources accounted for 77.5% of NO_x emissions (~1,380 lbs/day) and 7.7% of CO emissions (~1,200 lbs/day) emitted by midstream and upstream oil and gas sources in 2012. Both of these constituents are ozone precursors and contribute to the secondary formation of $PM_{2.5}$.

We compared these 2012 estimates to 2018 CAP emission estimates provided in Appendix I of South Coast's *Draft 2021 PM_{10} Maintenance Plan for the South Coast Air Basin* (SCAQMD, 2021). These estimates, included in **Table 4.5**, show that emissions from the oil and gas industry decreased from 2012 to 2018 for all CAPs, with the exception of NO_x emissions (increased by ~140 lbs/day). While total emissions from oil and gas sources generally decreased over time, emissions from upstream oil and gas production sources, such as oil and gas well sites did not. Total organic gas emissions from upstream production sources increased by ~5,420 lbs/day from 2012 to 2018; NMVOCs by ~1,700 lbs/day; CO and NO_x by ~60 lbs/day; and SO_x emissions by ~120 lbs/day (SCAQMD, 2012, 2021).

This trend is more clearly defined when the contribution from upstream oil and gas activities in 2012 is compared to emissions in 2018. Oil and gas production contributed 3.5% of total oil- and gas-related NMVOC emissions in 2012, while in 2018, oil and gas production accounted for 10.2% of emissions. A similar trend can be seen when comparing SO_x estimates. In 2012, production accounted for 1.7% of emissions whereas in 2018, production was responsible for 21.9% of total SO_x emissions from oil and gas sources. The large reductions in midstream oil and gas processes that have been achieved (e.g., petroleum refining), suggest it is possible to reduce emissions from upstream oil and gas production sites. CAPs from oil and gas production that increased from 2012 to 2018 are highlighted in red in **Table 4.5**. Note that we converted all estimates to pounds per day (lbs/day) for ease of comparison.

Table 4.5. 2012 and 2018 emissions (lbs/day) by major relevant source category for the South Coast Air Basin. We did not compare 2018 estimates of TACs to 2012 concentrations, as 2018 estimates were not readily available. This is noted in cells with "NA". Source: Adapted from Appendix VIII, SCAQMD (2012), and Appendix I, SCAQMD (2021).

Code	Source Category	*TOG*	*VOC*	*CO*	*NO_x*	*SO_x*	*TSP*	*PM_{10}*	*$PM_{2.5}$*	*Benzene*	*Formaldehyde*	*Toluene*	*Diesel PM*	*$DPM_{2.5}$*	*Elemental carbon*	*$EC_{2.5}$*
		2012 Criteria Air Pollutants (lbs/day)								*2012 Constituents of Concern (lbs/day)*						
30	***Oil and Gas Production (Combustion)***	***1,760.0***	***200.0***	***1,080.0***	***1,220.0***	***20.0***	***200.0***	***200.0***	***200.0***	***25.4***	***60.7***	***12.6***	***25.0***	***24.2***	***51.2***	***50.8***
40	Petroleum Refining (Combustion)	8,840.0	2,560.0	10,120.0	0.0	0.0	3,240.0	3,120.0	3,080.0	12.8	284.4	6.3	0.0	0.0	453.6	441.4
310	***Oil and Gas Production***	***4,760.0***	***2,700.0***	***120.0***	***160.0***	***0.0***	***20.0***	***20.0***	***20.0***	***31.7***	***9.9***	***17.5***	***0.0***	***0.0***	***7.1***	***7.1***
320	Petroleum Refining	12,280.0	8,220.0	9,960.0	380.0	1,120.0	5,680.0	3,640.0	3,160.0	46.5	621.2	98.0	0.0	0.0	235.1	240.8
330	Petroleum Marketing	235,840.0	69,340.0	0.0	20.0	20.0	0.0	0.0	0.0	211.2	0.0	2,926.1	0.0	0.0	0.2	0.2
399	Other (Petroleum Production and Marketing)	40.0	40.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.0	0.7	0.0	0.0	0.5	0.5
Total emissions from O&G (2012)		**263,520**	**83,060**	**21,280**	**1,780**	**1,160**	**9,140**	**6,980**	**6,460**	**328**	**976**	**3,061**	**25**	**24**	**748**	**741**
	% of emissions from upstream activities	***2.5%***	***3.5%***	***5.6%***	***77.5%***	***1.7%***	***2.4%***	***3.2%***	***3.4%***	***17.4%***	***7.2%***	***1.0%***	***100.0%***	***100.0%***	***7.8%***	***7.8%***
		2018 Criteria Air Pollutants (lbs/day)								*2018 Constituents of Concern (lbs/day)*						
30	***Oil and Gas Production (Combustion)***	***2,220.0***	***240.0***	***1,220.0***	***1,420.0***	***20.0***	***200.0***	***180.0***	***180.0***	***NA***	***NA***	***NA***	***NA***	***NA***	***NA***	***NA***
40	Petroleum Refining (Combustion)	12,960.0	2,660.0	9,740.0	0.0	20.0	3,560.0	3,540.0	3,540.0	NA	NA	NA	NA	NA	NA	NA
310	***Oil and Gas Production***	***9,720.0***	***4,360.0***	***40.0***	***20.0***	***120.0***	***80.0***	***60.0***	***40.0***	***NA***	***NA***	***NA***	***NA***	***NA***	***NA***	***NA***
320	Petroleum Refining	12,700.0	8,860.0	4,780.0	460.0	480.0	3,740.0	2,500.0	1,760.0	NA	NA	NA	NA	NA	NA	NA
330	Petroleum Marketing	109,580.0	27,600.0	460.0	0.0	0.0	20.0	0.0	0.0	NA	NA	NA	NA	NA	NA	NA
399	Other (Petroleum Production and Marketing)	1,200.0	1,160.0	20.0	20.0	0.0	0.0	0.0	0.0	NA	NA	NA	NA	NA	NA	NA
Total emissions from O&G (2018)		**148,380**	**44,880**	**16,260**	**1,920**	**640**	**7,600**	**6,280**	**5,520**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**
	% of emissions from upstream activities	***8.0%***	***10.2%***	***7.7%***	***75.0%***	***21.9%***	***3.7%***	***3.8%***	***4.0%***	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**
	Oil and gas production emissions (2012)	**6,520**	**2,900**	**1,200**	**1,380**	**20**	**220**	**220**	**220**	**57**	**71**	**30**	**25**	**24**	**58**	**58**
	Oil and gas production emissions (2018)	***11,940***	***4,600***	***1,260***	***1,440***	***140***	***280***	***240***	**220**	*NA*	*NA*	*NA*	*NA*	*NA*	*NA*	*NA*

For many air pollutants, upstream OGD contributes relatively less emissions than other pollution sources at a regional scale. For example, benzene emissions from oil and gas production accounted for <1% of total emissions from all major sources in the South Coast (SCAQMD, 2012). This is consistent with previous emissions inventory studies conducted in the South Coast Air Basin (Brandt et al., 2015), which also found upstream oil and gas sources contribute <1% of total emissions from all major sources in the South Coast region. However, as noted above, emissions from upstream OGD contribute substantially to localized air pollution near wells.

Mellqvist et al. (2019) estimates emission fluxes (kg/hr) of ammonia, alkanes, SO_x, NO_2, BTEX, methane, and formaldehyde from oil and gas sources in the San Joaquin Valley using a mix of methods similar to those implemented in Mellqvist et al. (2017). Sites were surveyed over a three-week period in October 2019. The first two weeks were dedicated to surveying emissions from the Lost Hills oil and gas production area, while the last week was dedicated to sampling of different oil and gas sources in the San Joaquin Valley, specifically the Cymric, McKittrick, and Belridge oil fields, as well as emissions from produced ponds in the Cymric/McKittrick and Taft fields (Mellqvist et al., 2019).

Average emission fluxes from the Lost Hills oil and gas production area were estimated to be 522 kg/hr for alkanes, and 244 kg/hr for methane emissions over the sampling period (**Table 4.6**) (Mellqvist et al., 2019). Higher average emission fluxes were observed from the Cymric & McKittrick oil and gas production area, with estimated alkane and methane fluxes of 1,380 and 2,430 kg/h over the sampling period (Mellqvist et al., 2019, see Table S1). The highest average alkane flux of 2,970 kg/h was observed in the Cymric & McKittrick Belridge production area (Mellqvist et al., 2019, see Table S1). Larger sources of emissions were found to occur during workover activities and activities at other oil rigs, as well as from vacuum trucks accessing the oil and gas field, with the largest permanent source of emissions attributed to separators operating within the field.

Finally, a neighborhood health investigation conducted at the AllenCo Energy Facility, located in the University Park Community in Los Angeles, found the facility's operational emissions to adversely affect the health of nearby residents (LACDPH, 2018). The AllenCo facility consisted of seven oil production wells on-site, and an additional 14 production wells located at various locations nearby, with the closest resident located 60 feet (18 m) from an active well. Between 2010 to 2014, the SCAQMD received nearly 300 odor complaints, conducted 150 inspections, and issued 18 notices of violation (SCAQMD, 2018b). Complaints from University Park residents were recurrent and included reports of headaches, nausea, and irritation to the eyes, nose, throat and airway (LACDPH, 2018).

Sampling results in 2011 indicated very low levels of H_2S emissions; however, the U.S. Environmental Protection Agency (EPA) and county health investigators suspected that constant exposure to even low levels of pollutants such as H_2S were associated with the symptoms reported by community members (Sahagun, 2013a, 2013b). Additionally, one sample, taken from a wastewater tank discharge line, found hydrocarbon levels to be 10,000 times higher than ambient concentrations (Sahagun, 2013a). As stated by the Los Angeles County Department of Public Health (LACDPH), the petroleum-based compounds emitted at the AllenCo facility appeared to be "well below levels that would lead to long-term systemic health effects. However, intermittent exposure to low level emissions can cause recurrent short-term health effects with symptoms consistent with those reported by neighboring residents" (LACDPH, 2018). The Director of Environmental Health for Los Angeles County agreed with this conclusion, stating that symptoms described by nearby residents "are not inconsistent with what we would expect to see after exposure to low levels of hydrocarbons. So, while the detectable concentrations of hazardous pollution may be below regulatory standards, they are nonetheless making people sick" (Los Angeles Times, 2013b).

4.2.2.2 Source assessment studies conducted outside California

A total of 20 peer-reviewed studies focused on air monitoring and modeling of air pollutant emissions from upstream OGD outside of California. Four were conducted in Pennsylvania (Goetz et al., 2015, 2017; Maskrey et al., 2016; Yuan et al., 2015), seven were conducted in Texas (Allen, 2016; Brantley et al., 2015; Marrero et al., 2016; Rich & Orimoloye, 2016; Roest & Schade, 2017; Zhou et al., 2021; Zielinska et al., 2014), three were conducted in Utah (Ahmadov et al., 2015; Helmig et al., 2014; Koss et al., 2015; Oltmans et al., 2016), two were conducted in Colorado (Hecobian et al., 2019; Milford, 2015), one was conducted in West Virginia (McCawley, 2015), and two were conducted across multiple states (Eisele et al., 2016; Johnson et al., 2018).

Texas

Studies in Texas found upstream OGD to have a significant impact on air quality. Rich & Orimoloye (2016) assessed air quality as a function of distance and found concentrations of various TACs, including benzene, to be higher in close proximity to active upstream OGD. Zielinska et al. (2014) found air quality impacts beyond a distance of approximately 100 m (328 ft) from gas wells and compressor stations in the Barnett Shale region to be indiscernible from background levels, suggesting that higher concentrations close to activity are observed. Source apportionment results from Zielinska et al. (2014) also demonstrate the significant contribution to regional NMVOCs from gas production sources in the Barnett Shale region, especially for alkanes with a low molecular weight. This corresponds with a study conducted in the Eagle Ford Shale, which estimated NMVOC emissions from the largest oil and gas facilities in the state (Zhou et al., 2021). Similarly, Eisele et al. (2016) measured NMVOC concentrations at an oil and gas site in the Texas Barnett Shale and found BTEX and styrene concentrations sampled within 60 m (197 ft) of the well site to be significantly higher than concentrations sampled 195 – 290 m (640 – 951 ft) from the site.

Marrero et al. (2016) collected whole air samples upwind and downwind from a number of upstream oil and gas sources in Texas. The authors found the highest hexane and m- & p-xylene mixing ratios to be observed downwind of well pads with compressors, where methane leak rates were highest; the highest toluene and benzene mixing ratios were found near oil-producing wells. Estimates of hexane, benzene, and toluene in Texas were consistent with estimates in Colorado and Utah, suggesting that there may be some consistency in emissions profiles from upstream OGD across geographic regions (Marrero et al., 2016). Findings from another Texas-based study suggests that a small number of upstream oil and gas sources are responsible for a significant portion of methane and NMVOC emissions ("super emitters") (Allen, 2016). While it is still uncertain why specific sites become super emitters over other upstream sites, the evidence suggests that differences in operational practices at well sites, as well as operational failures of high-emitting oil and gas components like pneumatic controllers and compressors, are potential factors (Allen, 2016).

Findings from Roest & Schade (2017) in Texas confirmed methane and non-methane hydrocarbons are indeed co-emitted from liquid storage tanks, with alkane mixing ratios increasing in the Eagle Ford Shale region in tandem with increasing oil and gas production rates. The largest fraction of methane emissions identified in Brantley et al. (2015) were found in tank samples collected from a dehydrator (64.4%), which is a device used to remove excess water vapor from gas (Brantley et al., 2015).

Pennsylvania

In the Marcellus Shale region of Pennsylvania, Goetz et al. (2015) performed a tracer study 480–1,100 m (1,575–3,609 ft) downwind of several gas facilities (eight compressor stations, two transient well pads for drilling and completion, and four production well pads) to measure and compare methane, ethane, and combustion by-product emission rates. They observed compressors and transient sites, followed by production sites to be the largest emitters of methane, CO, NO_x, and CO_2. The greatest ethane emission rates were measured at well production sites, although ethane emission rates were not reported for transient sites. They did not detect benzene or toluene in any plumes downwind of the sites, and detected elevated levels of methanol in only one plume downwind of a compressor site.

This is consistent with findings from Goetz et al. (2017), which identified gas well pads as significant sources of methane, ethane, and CO, but not major contributors of toluene and benzene. This may be due to the presence of dry-gas wells in the northeast region, as opposed to wet gas, which is composed of methane and other light alkanes (Goetz et al., 2017). Ethane to methane enhancement ratios were found to be consistent with ratios similar to dry gas, consistent with this hypothesis. Another Pennsylvania study (Yuan et al., 2015) found methane to benzene enhancement ratios to be consistent with emissions signatures associated with upstream OGD. The authors note that ~10% of facilities (e.g., gas processing facilities, compressor stations) accounted for ~40% of methane emissions observed in the monitored regions, highlighting the potential presence of super-emitting facilities that require further mitigation. One study conducted in Pennsylvania found operations at the well pad did not significantly impact local air concentrations of $PM_{2.5}$ and NMVOCs (Maskrey et al., 2016).

Utah

In Utah's Uintah Basin, surface and vertical profile observations of NMVOCs identified highly elevated levels of atmospheric NMVOCs, including benzene and toluene, at 200−300 times above the regional and seasonal background during temperature inversion events in 2013 (Helmig et al., 2014). These observations suggest a causal link between oil and gas emissions and, accumulation of TACs in the atmospheric surface layer. Another study in Utah found methane emissions from a gas field to be significantly correlated with levels of ethane, propane, n-butane, i-pentane, n-pentane, hexane, benzene, heptane, toluene, octane, and xylenes (Oltmans et al., 2016). Emissions were traced to several upstream sources, including numerous well sites, gathering pipelines, compressor stations and two large processing plants. Consistency in the distribution of these NMVOCs with methane distributions suggests they are co-emitted (Oltmans et al., 2016). A 2015 study in the Uintah Basin found pollutant emission ratios to be consistent with contributions of emissions from oil and gas producing wells (Koss et al., 2015). In addition, the methane emission rate, extrapolated from the emission rate for benzene, was consistent with an independent evaluation of methane emissions using aircraft measurements (top-down) from 2012. Another Utah-based study evaluated emissions from oil and gas operations using a top-down (i.e., aircraft measurements) and bottom-up (i.e., emissions inventory) approach (Ahmadov et al., 2015). They found high emissions of NMVOCs compared to emissions of NO_x, suggesting oil and gas operations are a significant source of ozone in the region.

Colorado

In Colorado, Hecobian et al. (2019) found variations in measured emission rates of TACs and NMVOCs at the various stages of production in the Denver-Julesburg and Piceance Basins in Colorado. Emission rates differed depending on the basin and phase of production, with flowback operations accounting for the highest levels of light and heavy alkane (e.g., n-hexane, n-heptane) emissions among all the sites sampled. Drilling and production activities produced elevated levels of light alkane emissions (e.g., ethane, propane, n-butane), but at much lower levels than during hydraulic fracturing and flowback operations. When the duration of operations is considered, however, drilling and production activities could still present a significant risk, as drilling and production activities (including conventional methods) are continuous (e.g., ≥8 hours per day) and generally fixed in one location (i.e., longer exposure duration), whereas stimulation treatments and flowback operations occur over shorter intervals (e.g., 5 hours of operation per day) and move from location to location (Hecobian et al., 2019). Similarly, Eisele et al. (2016) measured NMVOC emissions at oil and gas sites in Colorado and Texas and found benzene and toluene concentrations at the well pad to be significantly higher in the Denver-Julesburg Basin compared to downtown Denver.

These findings are consistent with findings from Milford (2015), which identified diesel-powered drill rigs and natural gas-powered compressor stations as the largest contributors to emissions of NO_x in Colorado. In addition to NO_x, large reciprocating natural-gas powered compressors are significant sources of NMVOCs, CO, PM, CO_2, and methane; diesel fuel-powered drill rigs are significant sources of PM, NMVOCs, and sulfur dioxide (SO_2) (Milford, 2015). The largest NMVOC emissions were attributed to “flashing losses from crude oil and condensate storage tanks, fugitive emissions from leaks in valves, fittings and other equipment, venting of hydrocarbons from completions and blowdowns, venting from glycol dehydration units and gas-driven pneumatic devices” (Milford, 2015).

The intensive use of service trucks, horizontal drilling rigs, and hydraulic fracturing pumps during unconventional OGD in the United States, all of which are typically diesel fuel-powered, are also sources of air pollution. Johnson et al. (2018) found engines used during hydraulic fracturing activities to produce the largest amount of NO_x emissions, drilling rigs produced large amounts of CO emissions, and diesel-powered trucks produced the largest total hydrocarbon emissions of all phases evaluated. McCawley (2015) evaluated releases from drill sites in West Virginia using tapered element oscillating microbalance (TEOM) 24-hour dust samples and found $PM_{2.5}$ and PM_{10} concentrations to not exceed 24-hr NAAQS. Average concentrations of ammonia, NO_X, ozone, and SO_2 "did not indicate a concern for ambient or occupational exposures," though the author did not offer direct comparison to standards for these pollutants (McCawley, 2015).

4.2.2.3 Exposure assessment studies conducted in the U.S.

The majority of exposure assessments found in the peer-reviewed literature and in government-sponsored reports were conducted outside of California. We identified 12 exposure assessment studies: three in California (CARB, 2021b; Deschenes et al., 2021; Garcia-Gonzales et al., 2019b); one in Colorado (Esswein et al., 2014); five in Pennsylvania (Banan & Gernand, 2018, 2021; Brown et al., 2015; Long et al., 2019, 2021); and three across multiple states (Garcia-Gonzales et al., 2019a; Haley et al., 2016; Macey et al., 2014).[3]

Garcia-Gonzales et al. (2019b) evaluated the distance decay gradient of air pollutant exposures from upstream OGD, and the potential impacts to health for residents in Los Angeles. The authors selected a facility in the West Adams community of South Los Angeles. Referred to as the Jefferson drill site, this facility is one of the top producers of oil and gas in California, operating 20 active oil and gas wells at the time of sampling and producing a total 8,890 million cubic feet (Mcf) of gas and 8,553 barrels (bbls) of oil in February 2016 alone. Homes within the West Adams community are located as close as 60 ft (18 m) to an active wellhead, exposing residents to health-damaging air pollutants released during operation.

The authors placed passive samplers at 11 home sites, three at the fence line of the Jefferson drill site (approximately 804 ft [245 m] from an active wellhead), and one approximately 2,460 ft (750 m) from the Jefferson drill site to act as a control. Pollutants were sampled for a two-week period and included measurements of n-pentane, n-hexane, benzene, and 2-butoxyethanol, all of which are known to be associated with upstream OGD (Garcia-Gonzales et al., 2019b). N-pentane, n-hexane, and benzene were found to be above the limit of detection for all samples (including the control), with the two-week time weighted average concentration being 0.51, 0.43, and 1.07 ppb, respectively (Garcia-Gonzales et al., 2019b). Benzene and n-hexane concentrations exceeded those found in the SCAQMD's MATES IV report on air quality in central Los Angeles (SCAQMD, 2015b).

Results from the distance decay analysis show a clear trend of decline in pollutant concentrations as you move away from the Jefferson drill site (Garcia-Gonzales et al., 2019b). To the east of the drill site (downwind), benzene concentrations decayed to background levels at 427 ft (130 m) from the closest wellhead, n-hexane concentrations decayed to background at 640 ft (195 m), and n-pentane concentrations decayed to background at 542 ft (165 m). To the west of the site

[3] Radioactive materials can also spread through airborne transport. However, this section does not include exposure assessments focused on radioactivity from OGD. For more information related to OGD and radioactive materials, see Chapter 2.

(upwind), n-pentane concentrations were highest near the facility; benzene and n-hexane concentrations, however, exhibited the opposite trend, increasing as distance from the facility increased. This pattern likely indicates the presence of other sources of pollution upwind from the Jefferson drill site, such as combustion emissions from the four-lane arterial roadway just west of the site. Results from the distance decay analysis suggest that residences downwind (east) from the Jefferson drill site are exposed to a higher pollution burden, with benzene concentrations increasing by 9%, n-hexane by 22%, and n-pentane by 24% from activity.

The Study of Neighborhood Air near Petroleum Sources (SNAPS) is a program under CARB that evaluates short-term, intensive air quality monitoring results in relation to proximity to oil and gas production facilities and other pollution sources in California (CARB, 2021b). For each site and community of interest, CARB staff will deploy stationary trailers equipped with sensors to measure ambient concentrations of NMVOCs, PM, metals, and CAPs for approximately one year (CARB, 2021b). Communities selected for the first round of monitoring include (1) Lost Hills, Lost Hills Oil Field, Kern County; (2) McKittrick and Derby Acres, McKittrick Oil Field and Midway-Sunset Oil Field, Kern County; (3) Baldwin Hills, Inglewood Oil Field, Los Angeles County; and (4) South Los Angeles, Las Cienegas Oil Field, Los Angeles County (CARB, 2018a).

The first and only site to undergo monitoring efforts at the time this report was prepared was the Lost Hills community neighboring the Lost Hills Oil Field in Kern County (CARB, 2018a). Monitoring efforts occurred over the course of a year starting in June 2019 and ending on April 29, 2020. CARB published preliminary data and analysis in a mid-monitoring update from the Lost Hills sampling campaign (CARB, 2019b). Of the 135 organic chemicals sampled each week, 10 were detected near the Lost Hills oil field, including TACs commonly associated with upstream oil and gas facilities such as benzene and H_2S (CARB, 2019b). Twenty-four metals were also detected during the sampling campaign, with concentrations of silicon, aluminum, calcium, and iron found to be higher on windy days, suggesting the source is from fugitive emissions of crustal dust at the site. On-site measurements of ozone and $PM_{2.5}$ used to estimate the air quality index (AQI) at the site found the AQI to be at “good” levels 53.8% of the time, at “moderate” levels 46% of the time, and at unhealthy levels for sensitive groups 0.2% of the time (CARB, 2019b). Preliminary findings demonstrate that all concentrations of detected pollutants were below the acute reference exposure threshold for those pollutants with state designated RELs.

A 2021 study evaluated the potential air quality impacts from oil and gas production under two different policy levers aimed at reducing oil and gas-related pollutant emissions in California (Deschenes et al., 2021). The first policy lever includes the implementation of either (1) a statewide oil production quota (potentially implemented through auctioned extraction permits), or (2) an equivalent tax on extraction for all new and existing wells, first from fields with more costly extraction then from less costly extraction fields. Results from this assessment found that tighter statewide crude oil production quotas not only lowers local air pollution exposure across California, but it also has an equity co-benefit by minimizing the gap in pollution exposure for disadvantaged communities (Deschenes et al., 2021). Furthermore, if the production quota is implemented through auctioned extraction permits, the additional state funding could be directed towards decarbonization efforts.

The second policy lever implements setback distances that prohibit extraction from new and existing oil wells within a certain distance of occupied areas at risk of exposure, including residences, schools, childcare and healthcare facilities, among others. Setback policies are more effective at mitigating harmful pollutant exposures than they are at achieving full decarbonization. However, setback policies would have a substantial impact on direct exposures to pollutant emissions from oil production for those living near oil well sites. Deschenes et al. (2021) found that a setback distance to wells of 2,500 ft (762 m) from residences, schools, playgrounds, childcare centers, elderly care and healthcare facilities would achieve a 49% reduction in greenhouse gas (GHG) emissions from 2019–2045. Finally, if the two policies were both implemented, the same improvements would be observed in aggregate with slightly fewer job losses.

Studies conducted in other states also found elevated levels of NMVOCs and TACs near oil and gas operations. An occupational exposure assessment conducted in Colorado by Esswein et al. (2014) found inhalation risks to oil and gas workers from benzene exposure to be associated with the amount of time spent working in close proximity to specific oil and gas operations (Esswein et al., 2014). Banan & Gernand (2018) measured $PM_{2.5}$ concentrations at varying locations around a typical well site (six wells per pad) in the Marcellus Shale in Pennsylvania in 2015 and concluded that the state's current setback distance policy of 152 m (500 ft) (58 PA. Cons. Stat. § 3215) is insufficient at protecting the public health of nearby residents. Results demonstrate that $PM_{2.5}$ concentrations 152 m (500 ft) away from a generic well site frequently exceeded the U.S. EPA's NAAQS health-protective (primary) standard annual average level of 12 $\mu g/m^3$ for $PM_{2.5}$ (Banan & Gernand, 2018). The authors recommend that Pennsylvania establish a minimum setback distance of 736 m (2,415 ft) to ensure compliance with health-protective (and other safety) thresholds for those individuals living within this radius of an active well site (Banan & Gernand, 2018).

Banan & Gernand (2021) also evaluated $PM_{2.5}$ concentrations in 2017 at varying locations around Pennsylvania well sites in relation to nearby populations. Consistent with findings from Banan & Gernand (2018), this study found that doubling the current setback distance to a distance of 305 m (1,000 ft) — from the current 152 m (500 ft) policy — would reduce the total number of $PM_{2.5}$ exceedances by 95% (Banan & Gernand, 2021). Brown et al. (2015) assessed air quality as a function of distance and found concentrations of various TACs in Pennsylvania, including benzene, to be higher in close proximity to active upstream OGD. Long et al. (2019) evaluated concentrations of 11 air pollutants[4] associated with upstream OGD in Pennsylvania and found a small fraction of measurements to exceed the acute and chronic "health-based air comparison values" in the Marcellus shale region ("peak" emissions), consistent with findings from Banan & Gernand (2018, 2021).

A minority of Pennsylvania studies found operations at the well pad to not significantly impact local air concentrations of $PM_{2.5}$ and NMVOCs (Long et al., 2021). Results summarized in Long et al. (2021) found all measurements of $PM_{2.5}$ and NMVOC monitoring at three locations approximately 1,000 ft to 2,800 ft (304 m to 853 m) away from a well pad to be "below health-

[4] $PM_{2.5}$, NO_2, SO_2, BTEX, acetaldehyde, formaldehyde, n-hexane, and H_2S.

based air comparison values, and thus do not provide evidence of either 24-hour or long-term air quality impacts of potential health concern at the school."

Consistent with findings in California, Colorado, and Pennsylvania, benzene is observed across the majority of studies investigating TACs associated with upstream OGD in the United States, regardless of the geographic focus of each study (Garcia-Gonzales et al., 2019a.). For example, Macey et al. (2014) assessed air emissions associated with upstream oil and gas activities in various locations within the United States and found significant concentrations of benzene and formaldehyde across Wyoming, Pennsylvania, and Arkansas (Macey et al., 2014). Upstream OGD operations in Wyoming and Pennsylvania were both found to have benzene concentrations in exceedance of acceptable risk levels (Macey et al., 2014). Macey et al. (2014) also found formaldehyde concentrations near compressor stations in Wyoming, Pennsylvania, and Arkansas that exceeded health-protective thresholds. Elevated levels of H_2S were found near sites in Colorado and Wyoming as well (Macey et al., 2014). Haley et al. (2016) evaluated setback policies in three oil and gas producing states (Colorado, Pennsylvania, and Texas) and found them all to be insufficient at protecting human health, allowing human exposure above the established limits for benzene and H_2S to occur.

4.2.2.4 Health risk assessments conducted in the U.S.

We identified six health risk assessment studies focused on upstream OGD exposure in the United States. These studies place findings in the context of human health by estimating potential cancer and/or non-cancer health risks from exposure to observed pollutant concentrations. The majority of studies were conducted in Colorado (Holder et al., 2019; McKenzie et al., 2012, 2018; McMullin et al., 2018), with only one study conducted in California (Shonkoff & Hill, 2020) and one study conducted in Texas (Bunch et al., 2014).

Shonkoff & Hill (2020) evaluated air monitoring data collected by independent consultants with guidance from CARB (CARB, 2018b). Air sampling occurred in five oil fields in the San Joaquin Valley and Kern County regions (North and South Belridge, Buena Vista Nose, Elk Hills, and Lost Hills) in California from December 2016 to December 2018. This study was conducted as a joint effort by CARB and the California Geologic Energy Management Division (CalGEM, formerly known as the Division of Oil, Gas and Geothermal Resources [DOGGR]). 8-hr continuous samples were taken at eight sites within 300 to 500 ft (91 m to 152 m) of an oil and gas well undergoing well stimulation activities; in addition, measurements were taken at the perimeter of the well during cleaning activities post-stimulation. Sampling efforts sought to collect air monitoring data at locations representative of the background (air quality of the general oil field) and ambient concentrations (regional air quality away from oil and gas activity) for the region, to act as a control for comparison to emissions from well stimulation activities, specifically (CARB, 2018b).

Shonkoff and Hill (2020) relied upon the Office of Environmental Health Hazard Assessment's (OEHHA) health risk assessment guidance to evaluate cancer and noncancer health risks from oil and gas exposure. Lifetime excess cancer risk was estimated by multiplying the average daily inhalation dose by the cancer potency factor, while noncancer health risks (chronic and acute exposures) were estimated using OEHHA's RELs, the Agency for Toxic Substances and Disease Registry (ATSDR) Minimal Risk Levels (MRLs), the U.S. EPA's reference concentrations, and the U.S. EPA's Provisional Peer-Reviewed Toxicity Value (Shonkoff & Hill, 2020).

Over the two-year sampling period (2016–2018), sixty-four individual compounds were detected in the 8-hr continuous samples. Of these detected compounds, 59% (38 compounds) were identified as health-relevant state- or federally-designated air pollutants[5], and 34% (22 compounds) of which are known or suspected human carcinogens (Shonkoff & Hill, 2020). Cumulative lifetime excess cancer risks were found to exceed the U.S. EPA *de minimis* threshold (1 case in one million) at each sampling location type (ambient, background, well stimulation and cleanout), with levels detected at ambient locations representing the highest lifetime cancer risks (Shonkoff & Hill, 2020). While the ambient monitoring locations were intended to act as a control, the authors note that "the proximity of off-field (ambient) locations to oil field activities and the similarities observed between off-field and on-field air quality suggest off-field (ambient) reference sites may be more reflective of oil field air quality than regional air quality" (Shonkoff & Hill, 2020). This statement is supported by evidence from a companion study, (Stringfellow & Camarillo, 2020), in which the authors concluded that the proximity of ambient sampling locations to oil and gas fields suggests that the chosen ambient sampling locations are not actually indicative of off-field air concentrations.

Excess cancer risks during both hydraulic fracturing activities and cleanout events were largely driven by concentrations of formaldehyde and benzene, with hydraulic fracturing activities resulting in a cumulative excess cancer risk of 62 in one million and cleanout events resulting in an excess cancer risk of 46 in one million, assuming continuous 8-hour exposures over a 70-year lifetime, per guidance for assessing cumulative lifetime cancer risk (Shonkoff & Hill, 2020). These findings are significant, as risks not only exceed the *de minimis* significance threshold, but they also exceed three SCAQMD significance thresholds of 1, 10, and 25 in one million, and both SJVAPCD significance thresholds of 1 and 20 in one million excess cancers (see Appendix D for more detail). Benzene was found to contribute 85% of the total cancer risk observed at these "ambient" sampling locations, a compound that is co-emitted during upstream oil and gas activities. Benzene was also the main driver for noncancer adverse health impacts associated with exposure, evidenced by the elevated acute and chronic hazard quotients (HQ, HQs>1) greater than 1, and by the elevated acute and chronic hazard indices (HI, HIs>1) at "ambient" sampling locations (Shonkoff & Hill, 2020).[6]

The authors note that these cancer risk estimates are conservative, as well stimulation treatment activities "are relatively short-lived and only represent a limited set of activities involved in OGD that warrant further investigations into potential air quality impacts" (Shonkoff & Hill, 2020). Even so, this study provides useful insight into the cumulative health risks that may be associated with oil and gas production in California. In addition, studies conducted outside of California clearly demonstrate that oil and gas production activities, when accounting for specific phases of production, emit continuous amounts of harmful air pollutants.

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[5] "Health-relevant air pollutants" include state designated TACs and federally designated TACs.
[6] See Appendix D for description of HQs and HIs and how they are estimated.

Studies conducted in Colorado also suggest that significant health risks exist to residents as a function of proximity to upstream oil and gas activity. Holder et al. (2019) clearly demonstrates that cancer risks and noncancer health risks associated with acute, subchronic and chronic exposures are reduced as distance from oil and gas sites increases. Holder et al. (2019) also found potential for noncancer adverse health effects associated with acute exposures to 2-ethyltoluene, 3-ethyltoluene, toluene, and benzene, and for respiratory, nervous, and hematologic (i.e., blood) target organ systems. These results applied to the highest-exposed hypothetical individuals and were found to persist out to 2,000 ft (610 m) for benzene exposure, as well as for neurologic and hematologic effects.

McKenzie et al. (2012) also found noncancer health risks associated with subchronic exposures as well as cancer risks, to be greater for residents living within ½ mi (2,640 feet, 805 m) from oil and gas wells, as compared to those living beyond ½ mi (2,640 feet, 805 m). These findings are specific to respiratory, neurological and hematological target organ systems. Increased risk was driven primarily by exposure to trimethylbenzenes, xylenes, and aliphatic hydrocarbons; slightly elevated excess lifetime cancer risk estimates were also driven by benzene exposure (McKenzie et al., 2012).

McKenzie et al. (2018) found that lifetime excess cancer risks exceeded the U.S. EPA *de minimis* threshold (1 case in one million) at all locations, including background, and began to increase over background at 501 to 610 m (1,673 ft to 2,000 ft). While cancer risk associated with exposure to benzene exceeded the U.S. EPA *de minimis* threshold across all distances examined, McKenzie et al. (2018) observed that lifetime excess cancer risk clearly increases with proximity to upstream OGD. Considering air monitoring data collected within 350 to 3,700 ft (107 m to 1128 m) of oil and gas sites in Colorado, lifetime excess cancer risks were estimated at 4.3 cases per 100,000 individuals, also exceeding the U.S. EPA *de minimis* threshold by more than an order of magnitude (McMullin et al., 2018). The lifetime excess cancer risk estimate reported by McMullin et al. (2018) also fell within the range reported by McKenzie et al. (2018) within similar distances from oil and gas sites (5.7 cases per 100,000 compared to one case per 10,000).

It is important to note that Holder et al. (2019) only considered cancer risks associated with exposure to benzene and did not consider exposures to other possible or probable carcinogens, as did McKenzie et al. (2018) and McMullin et al. (2018). Holder et al. (2019) recognize that because they only considered benzene, total cancer risks were likely underestimated, although the degree of underestimation is unknown. Despite this limitation, they found that excess lifetime cancer risk below the U.S. EPA *de minimis* threshold was only achieved at a distance beyond 1,800 ft (549 m) from the well pad when considering various combinations of benzene exposure and risk estimate scenarios.

Numerous oil and gas-associated TACs have been detected at distances beyond 500 ft (152 m) from the well pad, out to distances of approximately 1,600 m (1 mi) (McKenzie et al., 2018). Consistent with findings in California, Colorado, and Pennsylvania, benzene is observed across the majority of studies investigating TACs associated with upstream OGD in the United States, regardless of the geographic focus of each study (Garcia-Gonzales et al., 2019a; Haley et al., 2016; Macey et al., 2014).

In addition to the acute and chronic health outcomes documented, many oil and gas pollutants also have endocrine-disrupting properties. Endocrine disruptors can cause harmful effects at low doses and the timing of exposure influences the risk of outcome (Bolden et al., 2018). Furthermore, risk assessment studies often do not account for the full suite of air contaminants near oil and gas sites and are likely underestimating cancer and non-cancer health risks, particularly for compounds that affect similar adverse pathways, and are likely to adversely impact vulnerable population groups.

One study in Texas, Bunch et al. (2014), did not find a positive correlation between proximity to oil and gas activity and air pollutant concentrations. This may be due to the fact that the study relied upon regional concentrations of pollutants in Texas rather than samples conducted at the community level; community level sampling often captures differences in local emissions concentrations and are therefore more relevant to human health exposure than regional sampling efforts (Shonkoff & Gautier, 2015).

4.2.3. Summary of findings

The body of literature focused on oil and gas-associated air pollution exposures provides sufficient evidence that upstream OGD may present risks to human health.

4.2.3.1 California studies

Source assessment studies conducted in California found upstream oil and gas activities to be a substantial source of air pollutant emissions. Studies were conducted in Los Angeles and/or the South Coast region (Collier-Oxandale et al., 2020; Johnston et al., 2021; LACDPH, 2018; Mellqvist et al., 2017; Okorn et al., 2021; SCAQMD, 2015a, 2015b); the San Joaquin Valley (Mellqvist et al., 2019); and across OGD regions in California (Gonzalez et al., 2022).

The majority of studies focused on NMVOC and TAC emissions from and near upstream oil and gas activities. Findings from Johnston et al. (2021) show concentrations of methane, NMVOCs, BTEX, styrene, n-hexane, n-pentane, ethane, and propane to decrease once production at the site idled, with n-hexane decreasing by 68%, benzene decreasing by 32%, and toluene decreasing by 28%. The authors found oil and gas drilling during the active phase to contribute 23.7% of the total NMVOCs measured (Johnston et al., 2021). Two studies found high rates of total alkanes (e.g., pentane, hexane) associated with upstream OGD (Mellqvist et al., 2017, 2019). Mellqvist et al. (2017) found releases from oil and gas wells to be responsible for more than 50% of total alkane emissions surveyed.

Collier-Oxandale et al. (2020) and Okorn et al. (2021) both found elevated levels of non-methane hydrocarbons near oil and gas wells (e.g., within 1,640 ft [500 m] of activity as stated by Okorn et al., 2021). Results suggest that sources of combusted and volatilized hydrocarbons were likely impacting air quality throughout the surrounding community as well as near the oil and gas site (Collier-Oxandale et al., 2020), and that large, short-term increases in non-methane hydrocarbon emissions tend to occur more frequently in close proximity to activity (Okorn et al., 2021). LACDPH (2018) found hydrocarbon levels at a large production facility to be 10,000 times higher than ambient levels.

The SCAQMD's MATES IV study found oil and gas production to contribute a significant portion of formaldehyde, DPM, fine DPM, NO_x and CO emissions of major upstream oil and gas sources (SCAQMD, 2015b). Controlling for geographic, seasonal, meteorological, and time-trending factors, Gonzalez et al. (2022) observed elevated concentrations of $PM_{2.5}$, CO, NO_2, ozone, and NMVOCs downwind of wells on days with oil and gas activities, as far as 4 km away (13,123 ft). The most commonly detected constituents of concern near oil and gas sites were benzene, a known human carcinogen, and methane.

We identified three exposure assessments (CARB, 2021b; Deschenes et al., 2021; Garcia-Gonzales et al., 2019b) and one health risk assessment (Shonkoff & Hill, 2020) conducted in California. In a preliminary analysis, using preliminary data from the first few months of monitoring, CARB (2021b) detected 10 chemicals near active oil fields, including benzene and H_2S; measurements of ozone and $PM_{2.5}$ found the AQI on-site to be at "good" levels 53.8% of the time, at "moderate" levels 46%, and at unhealthy levels for sensitive groups 0.2% of the time (CARB, 2021b). While chronic exposure risks are still being investigated and are expected in a later report, all detected chemicals thus far were below acute state designated RELs (CARB, 2019b). Garcia-Gonzales et al. (2019b) measured pollutant concentrations near upstream OGD and found n-pentane, n-hexane, and benzene to be above the limit of detection for all samples, with benzene and n-hexane concentrations exceeding those found in the SCAQMD's MATES IV report on air quality in central Los Angeles, suggesting a local emissions source.

Shonkoff & Hill (2020) identified 38 health-relevant state or federally designated air pollutants and 22 known or suspected human carcinogens near upstream oil and gas sites. Calculated excess cancer risks during both hydraulic fracturing activities and cleanout events were largely driven by concentrations of formaldehyde and benzene (contributed to 85% of total risk), with hydraulic fracturing activities and cleanout events resulting in cancer risks that exceed the U.S. EPA *de minimis* threshold (one case in one million), SCAQMD significance thresholds of 1-, 10-, and 25-in one million, and SJVAPCD significance thresholds of 1- and 20-in one million excess cancers.

4.2.3.2 Studies outside California

Regardless of location, the vast majority of peer-reviewed air monitoring and modeling studies, exposure assessments, and health risk assessments outside California found significant concentrations of various TACs, including benzene, to be higher in close proximity to active upstream OGD. Only three studies in Texas and Pennsylvania did not find significant exposures associated with oil and gas as a function of proximity (Bunch et al., 2014; Long et al., 2021; Maskrey et al., 2016).

The majority of Texas studies found pollutant concentrations to decline as a function of distance (Rich & Orimoloye, 2016; Zhou et al., 2021; Zielinska et al., 2014). Significant concentrations of benzene and formaldehyde at oil and gas sites were found across Wyoming, Pennsylvania, and Arkansas, with formaldehyde concentrations in all three states to be above health-protective thresholds, and benzene concentrations in Wyoming and Pennsylvania to be above acceptable risk levels (Macey et al., 2014). Haley et al. (2016) found setback policies in Colorado (500 ft [152 m] or 1,000 ft [305 m] for high-occupancy building), Pennsylvania (500 ft [152 m]), and Texas (200 ft [61 m]) to be insufficient, allowing human exposure above the established limits for benzene and H_2S to occur.

In Colorado, the potential for noncancer adverse health effects from acute exposures have been estimated out to 2,000 ft (610 m) (Holder et al., 2019). Cancer risks and noncancer health risks associated with subchronic exposures were greater for those living within 2,640 ft (805 m) of OGD as compared to those living beyond 2,640 ft (805 m) from oil and gas wells (McKenzie et al., 2012). Additionally, cancer risk evaluations considering air monitoring data collected beyond 500 feet indicate elevated cancer risks above the U.S. EPA *de minimis* threshold for acceptable risk (1 in one million) out to 2,000 feet (610 m) from upstream OGD (McKenzie et al., 2018). Oil- and gas-associated compounds with evidence of endocrine activity have been detected beyond 500 feet (152 m), raising additional concerns about even low level exposures to these compounds at further distances, particularly during critical periods of fetal and early childhood development (Bolden et al., 2018).

Pennsylvania studies are consistent with studies in California, Colorado, and Texas (Banan & Gernand, 2018, 2021; Brown et al., 2015; Long et al., 2019). Banan & Gernand (2018) recommended that Pennsylvania establish a minimum setback distance of 736 m (2,415 ft). Banan & Gernand (2021) evaluated $PM_{2.5}$ concentrations at varying well sites and found that doubling the current setback distance to 305 m (1,000 ft) (from the current 152 m [500 ft] policy) would reduce the total number of $PM_{2.5}$ exceedances by 95%.

4.3. Approaches to emissions control and best practices implemented in California

4.3.1. Overview of federal controls & California emission requirements for oil & gas

The following section provides an overview of regulations and best practices intended to control air pollutant emissions from upstream OGD. This section is not intended to be an exhaustive list of every relevant regulation or rule, but rather acts as a summary of the current regulatory landscape in the state and elsewhere. In doing so, we hope to gain insight into potential gaps in emission control regulation at the federal, state, and local levels to inform our findings, conclusions, and recommendations.

4.3.1.1 Federal rules & regulations relevant to reducing emissions from upstream OGD

The Clean Air Act (CAA) [42 United States Code § 7401 et seq. (1970)], passed in 1970 and last amended in 1990, is a federal law that gives the U.S. EPA broad authority to regulate air emissions from stationary and mobile sources, and to implement air pollution prevention and control programs nationwide (US EPA, 2020a). The CAA requires the U.S. EPA's Office of Air Quality Planning and Standards (OAQPS) to set NAAQS and monitor and mitigate when areas are found to be in non-attainment (i.e., measured air pollutant concentration is greater than established safety threshold) (US EPA OAR, 2016a). Established NAAQS specify the allowable concentrations for six of the most common air pollutants in ambient air, otherwise known as CAPs, which include CO, lead, ground-level ozone, PM, NO_2, and SO_2 (US EPA, 2016d). In an effort to comply with NAAQS, each state is required to prepare an air quality control plan (referred to as a State Implementation Plan (SIP)) that incorporates regulatory controls for reducing air pollutant emissions in non-attainment areas (US EPA, 2020a). The U.S. EPA is responsible for reviewing each SIP to ensure that implementation will effectively reduce emissions to below NAAQS levels (US EPA, 2020a).

Sources of TAC emissions are controlled through a separate set of standards, as outlined in CAA Section 112 National Emission Standards for TACs (NESTAC) (US EPA, 2020b). These emissions standards are intended to prevent adverse health risks (non-cancer and cancer) from specific source types (US EPA, 2020b). The CAA also gives the U.S. EPA and other specified air agencies the authority to issue permits and set minimum performance standards for select source types to prevent significant deterioration of air quality (CalGEM, 2015; US EPA OAR, 2016b). Referred to as New Source Performance Standards (NSPS), emissions from new stationary sources can be reduced (under CAA Section 111(b)), as well as emissions from existing stationary sources, retroactively (under CAA Section 111(d)) (CalGEM, 2015; US EPA OAR, 2016b). **Figure 4.10** lists the federal regulations applicable to OGD in California (including well stimulation).

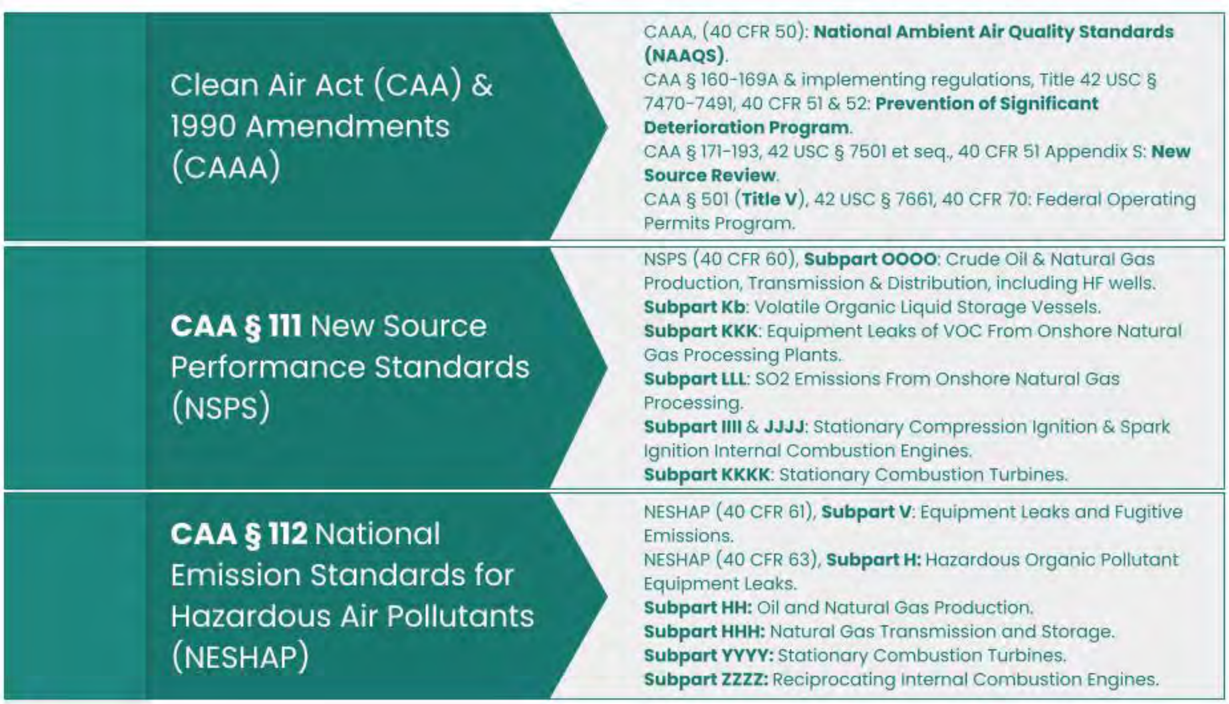

Figure 4.10. Current list of federal regulations applicable to OGD in California, including well stimulation techniques as well as conventional methods.

In 2016, the U.S. EPA updated the NSPS program to include specific permitting rules for upstream oil and gas sources constructed, reconstructed, or modified after September 15, 2015 (US EPA OAR, 2016b). As outlined in the CAA "2016 NSPS subpart OOOOa" and the *President's Climate Action Plan: Strategy to Reduce Methane Emissions*, the U.S. EPA issued three final rules within the NSPS program to reduce GHG (mainly methane) and NMVOC emissions from additional new, modified, and reconstructed sources in the oil and gas industry (US EPA OAR, 2016b). **Table 4.6.** provides a summary of the oil and gas source types subject to additional emission reductions under this federal rule. For sites with gas wells, new requirements for leak detection and repair were added, as well as requirements to limit emissions from pneumatic pumps (US EPA OAR, 2016c). For sites with oil wells, emission limits for hydraulically fractured oil well completions and pneumatic pumps were established, as well as new leak detection and repair (LDAR) requirements (US EPA OAR, 2016c).

Table 4.6. Oil and gas industry sources covered under 2012 NSPS for VOCs and the 2016 NSPS for Methane and VOCs. Source: US EPA (2016b).

Sources covered by the 2012 New Source Performance Standards (NSPS) for VOCs and the 2016 NSPS for Methane and VOCs, by site				
Location and Equipment/Process Covered	**Required to Reduce Emissions Under EPA Rules**	**Rules that Apply**		
		2012 NSPS for VOCs*	**2016 NSPS for methane**	**2016 NSPS for VOCs**
Natural Gas Well Sites				
Completions of hydraulically fractured wells	✓	•	•	
Compressors				
Equipment leaks	✓		•	•
Pneumatic controllers	✓	•	•	
Pneumatic pumps	✓		•	•
Storage tanks	✓	•		
Oil Well Sites				
Completions of hydraulically fractured wells	✓		•	•
Compressors				
Equipment leaks	✓		•	•
Pneumatic controllers	✓	•	•	
Pneumatic pumps	✓		•	•
Storage tanks	✓	•		
Production Gathering and Boosting Stations				
Compressors	✓	•	•	
Equipment leaks	✓		•	•
Pneumatic controllers	✓	•	•	
Pneumatic pumps				
Storage tanks	✓	•		
Natural Gas Processing Plants*				
Compressors	✓	•	•	
Equipment leaks	✓	•	•	
Pneumatic controllers	✓	•	•	
Pneumatic pumps	✓		•	•
Storage tanks	✓	•		
Natural Gas Compressor Stations (Transmission & Storage)				
Compressors	✓		•	•
Equipment leaks	✓		•	•
Pneumatic controllers	✓		•	•
Pneumatic pumps				
Storage tanks	✓	•		
*Note: Types of sources already subject to the 2012 NSPS requirements for VOC reductions that also are covered by the 2016 methane requirements will not have to install additional controls, because the controls to reduce VOCs reduce both pollutants				

In 2021 and 2022, the U.S. EPA proposed additional measures to further reduce GHG and NMVOC emissions from upstream OGD equipment (US EPA, 2023a). In 2023, the U.S. EPA issued a final ruling in which the following amendments to the NSPS and emissions guidelines were included, as outlined in **Table 4.7** (US EPA, 2023b).

Table 4.7. High-level overview of major provisions relevant to upstream oil and gas made to the 2012 and 2016 NSPS. Source: US EPA (2023b).

Description of Amendments from 2023 Ruling
"EPA is updating, strengthening, and expanding the current requirements under CAA section 111(b) for methane and VOC emissions from sources that commenced construction, modification, or reconstruction after December 6, 2022. These final standards of performance will be in a new subpart, 40 Code of Federal Regulations (C.F.R.) part 60, subpart OOOOb (NSPS OOOOb), and include standards for emission sources previously not regulated under the 2012 NSPS OOOO and 2016 NSPS OOOOa."
"New emissions guidelines (EG) will be added to a new subpart — 40 C.F.R. part 60, subpart OOOOc (EG OOOOc). The EG finalizes presumptive standards for GHG emissions (in the form of methane limitations) from designated facilities that commenced construction, reconstruction, or modification on or before December 6, 2022, and implementation requirements designed to inform states in the development, submittal, and implementation of state plans that are required to establish standards of performance for emissions of GHGs from their designated facilities in the Crude Oil and Natural Gas source category. The EPA is also finalizing regulatory language in NSPS OOOO, NSPS OOOOa, and NSPS KKK to provide clarity on when sources transition from being subject to these NSPS and become subject to a state or Federal plan implementing EG OOOOc."
"The EPA is taking several related actions stemming from the joint resolution of Congress, adopted on June 30, 2021, under the CRA [Congressional Review Act], disapproving the EPA's final rule titled, "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Review," 85 Federal Regulation (F.R.) 57018 (September 14, 2020) ("2020 Policy Rule"). The EPA is finalizing amendments to the 2016 NSPS OOOOa to address (1) certain inconsistencies between the VOC and methane standards resulting from the disapproval of the 2020 Policy Rule and (2) certain determinations made in the final rule titled, "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration," 85 F.R. 57398 (September 15, 2020) ("2020 Technical Rule"), specifically with respect to fugitive emissions monitoring at low production well sites and gathering and boosting stations. With respect to the latter, as described below, the EPA is finalizing the rescission of provisions of the 2020 Technical Rule that were not supported by the record for that rule or by our subsequent information and analysis. Additionally, the EPA updates the NSPS OOOO and NSPS OOOOa provisions in the C.F.R. to reflect the CRA resolution's disapproval of the final 2020 Policy Rule, specifically, the reinstatement of the NSPS OOOO and NSPS OOOOa requirements that the 2020 Policy Rule repealed but that came back into effect immediately upon enactment of the CRA resolution. *It should be noted that these requirements have come back into effect already, even prior to these updates to CFR text to reflect them. The EPA waited to make these updates to the C.F.R. text until the final rule simply because it was more efficient and clearer to amend the C.F.R. once at the end of this rulemaking process to account for all changes to the 2012 NSPS OOOO (77 F.R. 49490, August 16, 2012) and 2016 NSPS OOOOa at the same time."*
"The EPA is finalizing a protocol for the use of OGI in leak detection being finalized as appendix K to 40 C.F.R. part 60 (referred to hereafter as appendix K). While this protocol is being finalized in this action, the applicability of the protocol is broader. The protocol is applicable to facilities when specified in a referencing subpart to help determine the presence and location of leaks; it is not currently

applicable for use in direct emission rate measurements from sources. The protocol does not on its own apply to any sources. For NSPS OOOOb and EG OOOOc, the EPA is finalizing the use of the protocol for application at natural gas processing plants and may be applied to other sources only when incorporated through rulemaking to a specific subpart."

4.3.1.2 Federal emission control requirements: RACT, BACT, & LAER

Federal emission control requirements, as authorized under Part C, Title I of the federal Clean Air Act, fall under three categories: best available control technology (BACT), lowest achievable emission rate (LAER), and reasonably available control technology (RACT) (CARB, 2017a, 2017b).

Federal LAER is defined as either: (1) the most stringent of any emission control included in a SIP control strategy; or (2) the most stringent emission limit "achieved in practice," the definition of which varies from district to district (CARB, 2017a, 2017b). Unlike BACT, federal LAER does not require the inclusion of economic, energy, or environmental considerations when assessing the applicability of the rule to a major emitting facility (CARB, 2017a, 2017b). § 169(3) of the federal CAA defines BACT as an emission limit (based on the maximum degree of reduction of each pollutant) applicable to any major emitting facility (major sources) (CARB, 2017a, 2017b). In regions of federal nonattainment, new stationary sources, sources that undergo modification, and relocated sources which result in an emissions increase are subject to these additional emission control requirements (CARB, 2017a, 2017b). While there are federal requirements, California air districts have the authority to establish more stringent requirements for oil and gas at the local level. As a result, stringency levels differ by air district, as shown in **Table 4.8**, which summarizes how federal BACT and LAER definitions compare to district-level definitions of BACT & LAER (**Table 4.8**) (CARB, 2017b).

The final category of emission control requirements is RACT, which applies to existing sources in regions that are not meeting NAAQS (non-attainment) (US EPA OAR, 2016d). In 2016, the US EPA published *Control Techniques Guidelines for the Oil and Gas Industry*, which provides guidance for California's local air districts on what should be included as RACT for specific oil and gas emission sources (US EPA, 2016d).

Table 4.8. Comparison of California District Control Technology Definitions with Federal Definitions. Source: Table 9, CARB (2017b).

District	District BACT Definition *most similar to* Federal LAER Definition	District BACT Definition *most similar to* Federal BACT Definition	District LAER Definition *most similar to* Federal LAER Definition
Bay Area AQMD	x		
Butte Co. AQMD	x		
Colusa Co. APCD	x		
El Dorado Co. APCD Portion	x		
Feather River AQMD	x		
Glenn County APCD	x		
Great Basin Unified APCD	x		
Kern Co. APCD	x		
Lake Co. AQMD	x		
Lassen Co. APCD	x		
Modoc Co. APCD	x		
Mojave Desert AQMD	x		
Monterey Bay Unified APCD	x		
Placer Co. APCD Portion	x		
Placer Co. APCD Portion	x		
Sacramento Metropolitan AQMD	x		
San Joaquin Unified APCD	**x**		
San Luis Obispo Co. APCD	x		
Santa Barbara Co. APCD (NSR LAER)	x		
Shasta Co. AQMD	x		
Siskiyou Co. APCD	x		
South Coast AQMD	**x**		
Tehama Co. APCD	x		
Ventura Co. APCD	x		
Yolo-Solano Co. AQMD	x		
Amador Co. APCD		x	x
Calaveras Co. APCD		x	x
Imperial Co. APCD		x	x
Mariposa Co. APCD		x	x
Northern Sierra AQMD		x	x
San Diego Co. APCD		x	x
Mendocino Co. AQMD		x	
North Coast AQMD		x	
Northern Sonoma Co. APCD		x	
Santa Barbara Co. APCD (PSD BACT)		x	

Federal LAER (NSR) Definition: LAER is considered the most stringent of any emission control used in a state implementation plan (SIP) control strategy or the most stringent emission limit achieved in practice.
Federal BACT (PSD) Definition: Section 169(3) of the federal Clean Air Act defines BACT an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this Act emitted from or which results from any major emitting facility...New stationary sources, sources that undergo significant modification, and relocated sources which result in an emissions increase are subject to these additional emissions control requirements.

4.3.1.3 California rules & regulations relevant to reducing emissions from upstream OGD

In addition to federal controls, there are also California state-level requirements for emissions from upstream OGD. The regulation of air quality in California is different from other states, as the CAA gives California special authority to enact stricter air pollution standards than those established nationally (e.g., NAAQS). Implemented in 1988, the California CAA gives independent authority to the CARB to implement CAAQS, which represent more stringent, state-level thresholds for air quality attainment (CARB, 2017a). The responsibility of air quality management is shared between CARB and the 35 local air districts that make up the state's air basins (CalGEM, 2015). CARB is responsible for implementing the California CAA, and for the development and implementation of statewide air pollution control plans to achieve attainment with national standards (e.g., NAAQS) (CARB, 2017a). CARB also has authority to establish statewide strategies to control TAC emissions and set emissions standards for mobile sources (e.g., motor vehicles and off-road equipment) (CARB, 2017a). The local air districts are responsible for achieving and maintaining attainment with the CAAQS, which can be achieved through the development of an air quality management plan or clean air plan that assesses the feasibility of various emission control requirements to reduce emissions from major and minor sources in the region (CalGEM, 2015; CARB, 2017a).

Methane emissions from upstream OGD are controlled under C.C.R. Title 17, Subarticle 13: Greenhouse Gas Emission Standards for Crude Oil and Gas Facilities (CARB, 2017c). Adopted in March, 2017, this regulation includes standards for separator and tank systems, circulation tanks, LDAR, underground gas storage monitoring, gas compressors, pneumatic devices and pumps, and reporting requirements (CARB, 2017c, 2018c). Additionally, this regulation requires reductions in fugitive and vented emissions of methane from both new and existing oil and gas facilities (CARB, 2017c, 2018c). The following state regulations (currently codified) are applicable to air pollutant emissions from upstream OGD in California (including well stimulation) (**Figure 4.11**).

California Code of Regulations & Health and Safety Code	**HSC § 40910–40930:** Permitting of source required to be consistent with the ARB-approved CAP. **HSC § 39606, Ambient Air Quality Standards:** Gives ARB authority to set CAAQS. **HSC § 39656-39657, Toxic Air Contaminants:** Substances identified as HAPs in federal CAA must be regulated as TAC. **HSC § 41700, Nuisance Regulation:** Limits emissions that would cause nuisance or injury. **CCR, Title 17 Subarticle 13:** Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities **CCR, Title 17, Division 3, Chapter 1, Subchapter 10, Article 5:** California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms
California Clean Air Act (CCAA)	**CARB** coordinates/oversees state and local air pollution control programs & is responsible for implementing the **California Clean Air Act** & establishing **CAAQS**.
State programs for toxics & criteria air pollutants	California **Air Toxics "Hot Spots"** Information and Assessment Act ARB **Off-Road Mobile Sources Emission Reduction Programs** (i.e. Tier 2-4 equipment controls) CCR Title 13, Division 3, Chapter 9, Article 4, § 2423 ARB **Portable Equipment Registration Program** ARB **Airborne Toxic Control Measures** (ATCM): 13 CCR, Chapter 10, § 2485; 17 CCR § 93116; 17 CCR § 93115.4 and 93115.6

Figure 4.11. Current list of statewide regulations applicable to emissions from OGD in California. (Regulations relevant to plugged, idle, or abandoned wells included in Chapter 6.)

The stringency of local emission control requirements vary from district to district, and depends (largely) on the region's attainment status, severity of violation(s) with NAAQS, source size (major vs. minor sources), and how BACT rules and regulations are defined in each air district (CARB, 2017a, 2021c). In general, new and modified stationary sources and relocated sources that have an emissions increase are all subject to additional emissions control requirements (CARB, 2021a).

Operators must apply for a permit with the relevant air district prior to construction of any new, modified, or relocated source and New Source Review (NSR) may be triggered if emissions exceed established safety thresholds (CARB, 2021a). Not unlike the federal program, California's NSR permit program aims to protect air quality and public health by encouraging the use of the latest (and often lowest-emitting) technologies, as well as requiring the offset of any new emissions (while still accounting for economic impacts) (CARB, 2021a). In areas where pollutant levels are in attainment (or unclassifiable) with federal NAAQS, Prevention of Significant Deterioration (PSD) standards may be required. Applicable to any new major source or any major modifications to an existing source, the goal of PSD is to ensure that in regions of attainment, no new permitted source or combination of sources can result in a region's nonattainment for a particular pollutant. This is enforced through the use of PSD increments, defined as "the maximum allowable increase in concentration that is allowed to occur above a baseline concentration for a pollutant" (US EPA OAR, 2015a). If the amount of the new pollutant exceeds the applicable PSD increment, then significant deterioration is said to occur. Best available control technology for air toxics (T-BACT) may also be triggered for relevant sources that release TAC emissions (CARB, 2017a, 2017b, 2021a).

Emission control requirements for new or modified sources (i.e., BACT/T-BACT) in California are categorized into three levels: (1) Federal BACT, the least stringent; (2) Federal/State LAER, the most stringent at the state and federal level; and (3) California BACT, the most stringent at the local level (**Figure 4.12**) (CARB, 2021a).

Figure 4.12. Range of control levels that apply to new or modified stationary sources in California. Source: CARB (2021a).

Under state law, Federal BACT is triggered for sources in areas in nonattainment of the state's NSR program; under federal law, Federal BACT is required in regions of attainment where PSD standards may be required (CARB, 2021a). California BACT is authorized by the state, which allows air districts to implement emission control requirements beyond LAER limits, assuming the measures are technically feasible and cost effective (CARB, 2021a). Under state and federal law, LAER (both California and Federal) applies to sources in nonattainment of the federal NSR program (CARB, 2021a).

Finally, districts having moderate, serious, severe, or extreme air pollution may be required to implement expedited best available retrofit control technology (BARCT), as defined by § 40921.5, Chapter 10, Part 1, Division 26 of the California Health and Safety Code (HSC), Assembly Bill (AB) 617, and discussed in greater detail in Section 4.2.1 (CARB, 2020a). Similar to BACT, BARCT is an emissions threshold, and unlike BACT, BARCT is meant for *existing* stationary sources, not new or modified sources (CARB, 2020a). A recent requirement, air districts in nonattainment of NAAQS thresholds for CAP emissions were charged with the task of creating an "expedited BARCT schedule" by January 1, 2019, with implementation planned for December 31, 2023 (CARB, 2020a). These schedules are intended to control emissions from industrial sources subject to the Cap and Trade program (as of January 1, 2017), with the goal of reducing air pollutant emissions and protecting the health and safety of residents living close by (CARB, 2020a).

4.4. Gaps in existing emission control regulations with relevance to public health

After review of the various federal, state, and local emission control regulations applicable to upstream OGD activity in California, we identified gaps in existing emission control regulations where specific source types could be better controlled. When available, we refer to oil and gas regulations implemented elsewhere or at the local level to better inform the types of policy changes in which regulators may be interested. We also incorporate emissions estimates and equipment/component counts when available to determine (1) the impact that this change in policy would have on California's air quality and regional attainment status; and (2) the implications for those individuals being exposed to pollutants emitted during upstream OGD that are relevant to health.

4.4.1. TACs and NMVOCs are co-emitted with emissions of methane

In many cases reviewed in this section, emission estimates were not available for TACs and NMVOCs emitted by the various oil and gas components. Estimates of methane and other GHGs (e.g., CO_2, N_2O) were the most widely reported values provided by California-specific reports on upstream OGD. While methane does not contribute significantly to the formation of ground-level ozone or pose a health risk at the levels detected in ambient air near upstream oil and gas production sites, TACs, as well as precursor emissions to ground-level ozone (i.e., NMVOCs) are often co-emitted.

Rich et al. (2014) conducted a sampling campaign of residential sites located near unconventional shale gas extraction and production activity in the Dallas-Fort Worth region of Texas. Results confirmed the presence of methane (detected at 98% of sampling sites) and 101 other chemicals in the outdoor air of residences located within 200 ft (61 m), 2,000 ft (610 m), and 5,280 ft (1.6 km) of equipment used for unconventional OGD (Table 1, Rich et al., 2014). Approximately 20 of the detected chemicals were identified as TACs and included benzene (detected at 76% of sampling sites), 1,3-butadiene, carbon disulfide, carbonyl sulfide, chloromethane, tetrachloroethane, toluene, and xylene (Rich et al., 2014).

Concentrations of 15 detected chemicals were found to significantly correlate with methane levels, including pentane (C5), heptane (C7), and butane (C4) as well as TACs including hexachlorobutadiene, tetrachloroethene (PCE), 1,2,4-trichlorobenzene, and chloroform. The strongest correlation with methane was 3-methylhexane, a constituent of gas condensate (Rich et al., 2014). Significant correlations were also found among detected TACs, with the strongest relationships found between benzene and toluene, benzene, and m- & p-xylene, and toluene and m- & p-xylene.

Table 4.10 compares the results of Rich et al. (2014) to two studies conducted in Colorado (McKenzie et al., 2012; Pétron et al., 2012) and one study conducted in the U.K.[7] Levels of alkanes (e.g., ethane, propane, butane, pentane, and hexane) generally agreed across all three studies (McKenzie et al., 2012; Pétron et al., 2012; Rich et al., 2014). Concentrations of aromatic hydrocarbons (e.g., BTEX, trimethylbenzenes) from the Rich et al. (2014) study were generally higher than what was detected in the other studies. Similarly, methane concentrations were higher in Rich et al. (2014) compared to methane levels detected in Pétron et al. (2012).

[7] We disregard this last study, as it is out of the geographic scope of this report.

There are several additional studies that support the findings from Rich et al. (2014), McKenzie et al. (2012), and Pétron et al. (2012). For example, Koss et al. (2015) conducted a sampling campaign in the Uintah Basin, Utah, and found pollutant emission ratios to be consistent with contributions of emissions from both oil and gas producing wells. In addition, the methane emission rate, extrapolated from the emission rate for benzene, was consistent with an independent evaluation of methane emissions using aircraft measurements from 2012. Marrero et al. (2016) conducted a similar assessment in the Barnett Shale region of Texas and found the highest hexane and m- & p-xylene mixing ratios to be observed downwind of well pads with compressors, where methane leak rates were highest. Similarly, the authors found some of the highest toluene and benzene mixing ratios to be near oil-producing wells. The authors note that estimates of hexane, benzene, and toluene emissions in the Barnett Shale region were consistent with values witnessed in oil and gas producing regions of Colorado and Utah, suggesting that there may be some consistency in emissions profiles from oil and gas development across geographic regions (Marrero et al., 2016).

In Pennsylvania, the Goetz et al. (2015) sampling campaign of oil and gas sites in the Marcellus Shale region found elevated ethane and methane concentrations, with no other chemical significantly detected at sampling sites. With regards to emissions near oil and gas wells, results were somewhat variable — the smallest of the well pads (with seven wells) had the second largest methane concentrations of all well pad sites sampled (Goetz et al., 2015). This was likely because this well pad produces wet gas, which is high in methane and other hydrocarbons such as ethane (Goetz et al., 2015). Results at the remaining well sites found elevated levels of methane and ethane from combustion sources at all locations, in addition to elevated levels of CO and NO_x, an ozone precursor at one well location.

A study conducted by Hecobian et al. (2019) also found variations in measured emissions of TACs and NMVOCs at the various stages of production in the Denver-Julesburg and Piceance Basins in Colorado. As shown in **Figure 4.13**, emissions differed depending on the basin and phase of production, with flowback operations accounting for the highest levels of heavy alkane (e.g., n-hexane, n-heptane) emissions among all the sites sampled. Drilling and production activities produced elevated levels of light alkane emissions (e.g., ethane, propane, n-butane), but at much lower levels than during hydraulic fracturing and flowback operations. When the duration of operations is considered, however, drilling and production activities could still present a significant risk, as drilling and production activities (including conventional methods) are continuous (e.g., ≥8 hours of operation/day) and generally fixed in one location (i.e., longer exposure duration), whereas stimulation treatments and flowback operations occur over shorter intervals (e.g., 5 hours of operation/day) and move from location to location.

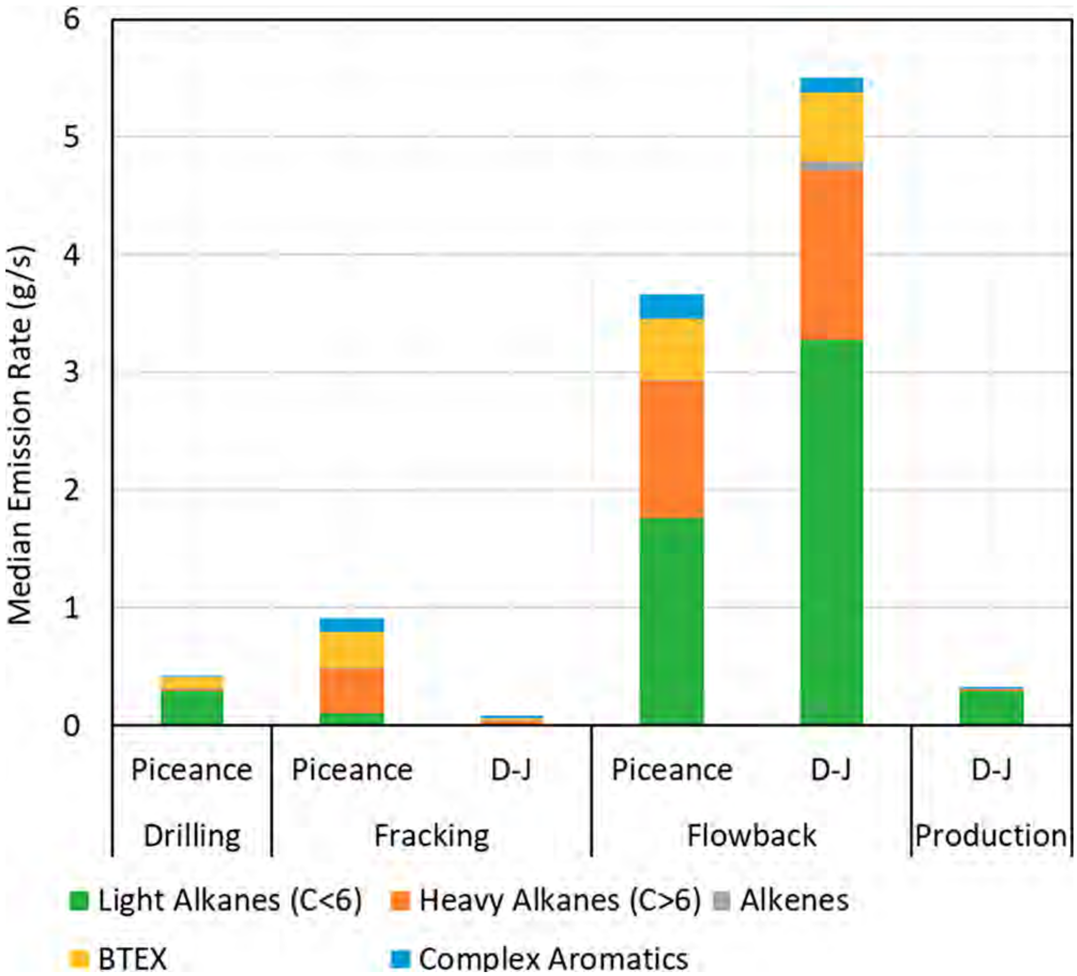

Figure 4.13. Emission rates of key NMVOCs by unconventional oil and gas activity in the Piceance Basin and Denver-Julesburg Basin. Source: Figure 1, Hecobian et al. (2019).[8]

There is substantial evidence that methane emissions from many upstream oil and gas sources are indeed co-emitted, and in some cases, significantly correlated with emissions of TACs and other NMVOCs. Methane and other pollutant emissions are released during many stages of upstream oil and gas production. Fugitive (unintentional) releases of methane, and associated NMVOCs can occur from component and equipment leaks, including from valves, screwed connections, flanges, open-ended lines, and pump seals (ExxonMobil, 2021; US EPA, 2016a). Direct venting of methane emissions can also occur during well stimulation treatments, specifically during flowback operations and manual liquids unloadings. In some cases, the intended function of a component results in the intentional release of methane emissions, such as is the case with gas-powered pneumatic devices, which directly release or "bleed" gas (ExxonMobil, 2021). NMVOCs and TACs are often co-emitted with methane releases from pneumatic controllers and

[8] Light Alkanes: ethane, propane, i-butane, n-butane, i-pentane, n-pentane; Heavy Alkanes: 2,3-dimethylpentane, 2,4-dimethylpentane, 2,2,4-trimethylpentane, 2,3,4-trimethylpentane, n-hexane, 2-methylhexane, 3-methylhexane, n-heptane, 2-methylheptane, 3-methylheptane, n-octane, n-nonane, n-decane; Alkenes: ethene, propene, t-2-butene, 1-butene, c-2-butene, t-2-pentene, 1-pentene, C-2-pentene; Complex Aromatics: styrene, i-propylbenzene, n-propylbenzene, 1,2,3-trimethylbenzene, 1,2,4-trimethylbenzene, 1,3,5-trimethylbenzene, 1,3-diethylbenzene, 1,4-diethylbenzene, 2-ethyltoluene, 3-ethyltoluene, 4-ethyltoluene; BTEX: BTEX benzene, toluene, ethylbenzene, o-xylene, m & p-xylenes.Source: Table S5, Hecobian et al. (2019).

pumps (US EPA, 2016a). Methane is the largest component of vapor releases from storage vessels, but these vapor releases may also include releases of n-hexane, alkanes (e.g., ethane, butane, propane) and TACs (e.g., BTEX) (US EPA, 2016a).

Additional sources of methane and associated NMVOCs from upstream OGD include releases from incomplete combustion (e.g., flaring), centrifugal and reciprocating compressors, and transmission pipeline blowdowns (ExxonMobil, 2021; US EPA, 2016a). Combustion and incomplete combustion (e.g., flaring) of organic pollutants also produces secondary pollutants including NO_x, CO, SO_x, and PM (US EPA, 2016a).

Many of the compounds detected at California oil and gas sites (e.g., benzene, alkanes) were identified as co-pollutants of methane in other oil and gas producing states. The most commonly detected constituents near oil and gas sites were benzene and methane, with estimated rates of benzene to be 12 kg/hr (Mellqvist et al., 2017) and ~57 lbs/day (SCAQMD, 2015b); concentrations of benzene to be 1.07 ppb ((Collier-Oxandale et al., 2020; Garcia-Gonzales et al., 2019b; Okorn et al., 2021); and rates of methane to be 244 kg/hr (Mellqvist et al., 2019) and 636 kg/hr (Mellqvist et al., 2017). The 1.07 ppb benzene concentration estimated in Garcia-Gonzales et al. (2019b) is greater than the median benzene concentrations (0.02 ppb–0.89 ppb) summarized in Table 3 of the Rich et al. (2014) study (**Table 4.9**). Therefore, in lieu of California-specific studies, these findings should be considered when determining risks to public health, especially in areas with high-intensity upstream OGD activities (e.g., production, hydraulic fracturing, acidizing) near residences and other sensitive receptors. The most important implication from this assessment is that significant reductions in methane could translate to potentially significant reductions in TACs, and ozone precursors emissions (e.g., NMVOCs), beyond what is currently being achieved in California.

Table 4.9. Comparison of Rich et al. (2014) air sampling results with other studies. Source: Table 3, Rich et al. (2014).

	This Study			Garfield County, Colorado[a]		Birmingham, UK[b]	Weld County, Colorado[c]	State of California[d]
Chemical	**Max (ppb_v)**	**Median (ppb_v)**	**Mean (ppb_v)**	**Max (ppb_v)**	**Median (ppb_v)**	**Range of Means (ppb_v)**	**Range of Medians (ppb_v)**	**Ambient Average (ppb_v)**
Methane (ppmv)	457	2.7	11.99				1.81—1.89	
Benzene	592	0.89	18.53	4.39	0.30	0.25-0.7	0.02-0.1	4.6
Chloroform	2.58	0.3	0.45					0.006-0.13
Dichloromethane/Methylene chloride	1	0.3	0.34					1.1—2.4
Ethylbenzene	113	0.53	4.42	1.87	0.04			
Styrene	43.4	0.37	1.91	0.80	0.035			10
Tetrachloroethene (PCE)	2.43	0.3	0.33					0.71
Toluene / Methylbenzene	276	2.55	19.45	21.0	0.48	0.7—1.9		
Trichloroethene (TCE)	60.9	0.3	1.58					0.22
1,3,5-Trimethylbenzene	9.95	0.59	1.43	0.25	0.024			
1,2,4-Trimethylbenzene	60.4	0.4	3.45	0.63	0.037			
m- and *p*-Xylene	221	1.68	15.69	2.28	0.20			
o-Xylene	39.4	0.85	3.19	0.83	0.05			
Propylbenzene	23.5	1.4	2.08	0.14	0.02			
Pentane	198	1.4	7.73	21.1	3.09	0.2—0.5	0.01—0.48	
Methyl cyclohexane	38	1.4	2.42	5.98	0.92			
Propane (ppmv)	62.9	1.4	2.97			0.8—2.8	0.1—3.0	
Butane (ppmv)	69	1.4	2.95			0.9—2.8	0.04—1.24	
Ethane (ppmv)	34.6	1.4	2.24			2.2—6.3		
Isobutane	34	1.4	3.95			0.8		
Methylpentane/Isohexane	199	1.4	6.1			0.15—1.1		
Hexane	35	1.4	2.46	7.11	1.14	0.1—0.2		

Notes: Values are reported by California Air Resources Board for California, except for benzene, which was reported for the South Coast Air Basin of California (Los Angeles metropolitan area). [a]McKenzie et al. (2023). [b]Hopkins et al. (2005). [c]Petron et al. (2012). [d]Seinfeld and Pandis (1998).

4.4.2. Regulation of gas-driven pneumatic devices in Colorado: A comparison with current California requirements

Like California, oil and gas regions in Colorado face similar challenges in achieving attainment with NAAQS thresholds for ozone (CDPHE AQCC, 2021). The Denver Metropolitan North Front Range was just recently recategorized by the U.S. EPA in April 2022 to be in “Severe” nonattainment of the 2008 8-hour ozone NAAQS, after 2020–2021 ozone concentrations exceeded the established safety limits (CDPHE, 2022). In California, 22 air districts are in nonattainment for the 2015 ozone NAAQS, 13 of which are classified as “moderate” to “extreme.” Of these 13 air districts, six have oil and gas operations subject to emission control (CARB, 2018d). A more detailed discussion of California’s nonattainment statuses can be found in Section 4.2.1.

Statewide, the oil and gas industry is the largest contributor of NMVOC emissions in Colorado (CDPHE AQCC, 2021). Natural gas-driven pneumatic controllers are collectively one of the largest sources of NMVOCs and the second largest source of methane emissions from oil and gas operations nationwide (CDPHE AQCC, 2021). These findings are significant, as ground-level ozone is formed when chemical reactions catalyzed by heat and sunlight occur between NO_x and NMVOCs (US EPA OAR, 2015b). Furthermore, depending on the level of exposure, ozone is associated with coughing, sore throat, difficulty breathing, inflammation of the airway and exacerbation of asthma, emphysema, and chronic bronchitis (US EPA OAR, 2015c).

Similarly, while methane does not pose a health risk at the levels detected in ambient air near upstream oil and gas production sites, TACs including benzene, toluene, and formaldehyde are often co-emitted. In the case of gas-powered pneumatic devices, the intended function of the component results in the release of methane emissions, which directly emit or “bleed” gas (ExxonMobil, 2021; US EPA, 2016a). Thus, significant reductions in methane emissions would also result in significant reductions of TACs and associated health risks.

Colorado’s *Regulation Number 7 - Statements of Basis, Specific Statutory Authority and Purpose* (Regulation Number 7) defines pneumatic controllers as,

> “a device that monitors a process parameter such as liquid level, pressure, or temperature and uses pressurized gas (which may be released to the atmosphere during normal operation) to send a signal to a control valve in order to control the process parameter. Controllers that do not utilize pressurized gas are not pneumatic controllers” (CDPHE AQCC, 2021).

According to Part F of Regulation Number 7, NMVOC emissions from gas driven pneumatic controllers within ozone nonattainment areas were estimated to be responsible for 14% (24.8 tons per day (tpd) and 15.1% (31.1 tpd) of total NMVOC emissions from oil and gas sources in 2006 and 2011, respectively (CDPHE AQCC, 2021).

The Colorado Department of Public Health and the Environment's Air Quality Control Commission (CDPHE AQCC) updated Regulation Number 7 to include requirements for the use of zero-bleed and zero-emission pneumatic control devices at oil and gas well sites (CDPHE AQCC, 2021)**.** Adopted on February 18, 2021, and effective on April 14, 2021, the following requirements are applicable to both new and existing natural-gas driven devices (CDPHE AQCC, 2021):

- All new and modified well production facilities and compressor stations that commence operations on or after May 1, 2021, are required to use non-emitting pneumatic control devices (i.e., those activated by compressed air or electricity as opposed to high-pressure gas); and
- All existing pneumatic control devices (defined as those in operation prior to May 1, 2021) must be retrofitted with zero-emission devices, through a phase in process, as outlined in Table 1 of Colorado's revised Regulation Number 7 (**Table 4.10**) (CDPHE AQCC, 2021).

Table 4.10. Required timeline for implementation of non-emitting devices on existing well production facilities. Source: Regulation Number 7, Table 1, CDPHE AQCC (2021).

Table 1*—Well Production Facilities					
Total Historic Non-Emitting Facility Percent Production	**May 1, 2022 Additional Required Non-Emitting Facility Percent Production**	**May 1, 2022 Maximum Required Non-Emitting Facility Percent Production**	**May 1, 2023 Additional Required Non-Emitting Facility Percent Production**	**May 1, 2023 Maximum Required Non-Emitting Facility Percent Production**	**Total Additional Required Non-Emitting Facility Percent Production By May 1 2023**
> 75%	+5%	90%	+10%	96.5%	+15%
> 60—75%	+5%	80%	+10%	90%	+15%
> 40—60%	+10%	65%	+15%	75%	+25%
> 20—40%	+15%	50%	+20%	65%	+35%
> 0—20%	+15%	35%	+25%	55%	+40%

*Table 1 establishes minimum increases in the percentage of liquids produced (based on historic non-emitting controller use) from non-emitting facilities. Owners or operators do not need to go beyond the maximum required percentages set forth in Table 1, although they may choose to do so.

In California, pneumatic control device and pump requirements are required by CARB's 2017 *C.C.R., Title 17, Division 3, Chapter 1, Subchapter 10 Climate Change, Article 4, Subarticle 13: Greenhouse Gas Emission Standards for Crude Oil and Gas Facilities* (Oil and Gas Methane Regulation) (CARB, 2018d). California's Oil and Gas Methane Regulation requires pneumatic controllers installed after January 1, 2016, to have a zero-bleed rate and those installed before this date to comply with the low-bleed rate of less than or equal to 6 standard cubic feet per hour (scfh) (CARB, 2018c). This differs, and is less stringent than, Colorado's Regulation Number 7, which requires all *existing* natural-gas driven pneumatic controllers to be retrofitted with zero-bleed technology via a phase-in process, in addition to new and modified sources.

Both regulations apply to the same or similar source types. California's Oil and Gas Methane Regulation covers pneumatic controllers at (1) gas processing plants, (2) between the wellhead and the gas processing plant, or (3) the point of custody transfer to an oil pipeline (CARB, 2018d). In Colorado, revisions to Regulation Number 7 apply to pneumatic controllers that are "actuated by gas, and located at, or upstream of gas processing plants," with upstream activities encompassing: (1) oil and gas exploration and production operations; and (2) gas compressor stations (CDPHE AQCC, 2021). Therefore, the key difference between Colorado and California's regulation of pneumatic devices is the stringency placed on emissions from existing low- and high-bleed pneumatic controllers — Colorado requires zero-bleed (retroactively) whereas California allows low-bleed rate devices to operate if they are grandfathered in.

If implemented, it is unclear how this type of policy would impact NMVOCVOC or TAC emissions from upstream OGD in California, in particular due to the lower prevalence of low-bleed devices. In 2007, CARB conducted a survey of the oil and gas industry. Referred to as *Final Report (Revised): 2007 Oil and Gas Industry Survey Results, Final Report (Revised), October 2013 (posted November 1, 2013)*, this survey gathered information on various components and methane emissions associated with crude oil and gas production, processing, and storage facilities in the state (CARB, 2013a). The survey identified 1,151 continuous bleed devices (e.g., high bleed) and 50 low-bleed devices (<6 scfh) in operation in California, accounting for ~86% and 1% of vented methane emissions emitted by automated control devices, respectively (CARB, 2013a).

Using emission rates for low-bleed devices from Table 6-2 of the U.S. EPA's *Control Technique Guidelines for the Oil and Gas Industry*, we were able to estimate the proportion of VOCs associated with these annual methane emissions estimates (**Table 4.11**) (US EPA, 2016a). Requiring replacement of low-bleed devices to zero bleed devices would result in a 15 tpy reduction in VOCs, approximately 0.3% of total vented VOC emissions.

Table 4.11. Estimate of vented emissions from pneumatic devices. Source: Tables 9-1 and 9-2, CARB (2013a).

Automated Control Device Type	No. of Devices	CH_4 (MT/yr)	VOCs (tpy)
Continuous Bleed	1,151	4,915	1,502
Low Bleed	50	46	15
Intermittent Bleed	405	760	-
Non-Emitting (e.g. electric, no bleed, air)	15,440	-	-
Control Device Total	**17,046**	**5,721**	**1,517**
Vented Emissions Total	**-**	**16,026**	**4,445**

It should be noted that these estimates are most likely an underestimation of the true contribution in emissions from gas-driven pneumatic devices for several reasons. Because the estimates provided are from 2007, these statistics may no longer be representative of 2020 inventories, as they are more than a decade old. Since 2007, these pneumatic devices may have been replaced upon failure with newer versions such as no-bleed units. Additional NMVOC and methane emissions reductions from the oil and gas sector would be possible if the state implemented a policy that applied zero-bleed/zero-emission standards to existing pneumatic controllers, retroactively, similar to revisions made to Colorado's Regulation Number 7. However, these emissions reductions represent a small fraction of overall vented emissions from control devices.

4.4.3. Separators and condensate tank systems: Exemptions from vapor recovery requirements for small producers

Methane is the largest component of vapor releases from storage vessels, but may also include releases of n-hexane, alkanes (e.g., ethane, butane, propane), and TACs (US EPA, 2016a). California's 2017 Oil and Gas Methane Regulation includes standards to control emissions from storage vessels, including separator and condensate tank systems, through the use of flash analysis testing and vapor collection systems (95% vapor control efficiency). § 95668(a) of the Oil and Gas Methane Regulation states:

- By January 1, 2018, owners and operators of existing separator and tank systems with uncontrolled emissions (i.e., no vapor collection system installed) are required to conduct flash analysis testing "of the crude oil, condensate, or produced water processed, stored, or held in the system."
- Starting January 1, 2018, new separator and tank systems are required to conduct flash analysis testing within 90 days (CARB, 2017c).

Results from the flash analysis testing are then used to determine which operators/owners are required to implement vapor collection systems. § 95668(a) of the Oil and Gas Methane Regulation states:

- Existing separator and tank systems with an annual emission rate of 10 metric tons (MT) or greater of methane per year (equivalent to ~1.8 MT/year VOCs) are required to control emissions via a vapor collection system by January 1, 2019 (as specified in § 95671).
- Starting January 1, 2018, new separator and tank systems with an emissions rate of 10 MT methane/year or greater (equivalent to ~1.8 MT/year VOCs) will be required to implement a vapor collection system within 180 days of flash analysis testing (CARB, 2017c, 2018d).

CARB outlines two key exemptions from the requirements. First, separators and tank systems that have a vapor collection system already installed and approved for use by the local air district by January 1, 2018, are exempt (CARB, 2017c). Air Districts that meet this exemption criteria include:

- Sacramento Metropolitan AQMD (Rule 446: Storage of Petroleum Products)
- San Joaquin Valley APCD (Rule 4623: Storage of Organic Liquids)
- South Coast AQMD (Rule 463: Organic Liquid Storage; Rule 1178: Further Reductions of VOC Emissions from Storage Tanks at Petroleum Facilities)
- Ventura County APCD (Rule 71.1: Crude Oil Production and Separation; Rule 71.2: Storage of Reactive Organic Compound Liquids)
- Yolo-Solano AQMD (Rule 2.21: Organic Liquid Storage and Transfer) (CARB, 2018d).

All of these district rules require the implementation of vapor collection systems to reduce emissions by at least 95%, consistent with state law; however, small producer definitions may vary from district to district.

Second, separators and condensate tank systems are exempt from vapor collection requirements if they "receive an average of less than 50 barrels of crude oil or condensate per day" or "receive an average of less than 200 barrels of produced water per day" for non-associated gas production systems (CARB, 2017c). Average daily production is estimated using the annual production volume, as reported to DOGGR (now CalGEM), divided by 365 days per year (CARB, 2017c). This "small tank producer" exemption was implemented by CARB, because systems that meet these specifications are not likely to produce a large enough volume of liquids to meet the methane emission standard of 10 MT methane/year and therefore do not require flash testing or a permanent vapor recovery system. CARB states,

> "Methane is emitted from the production of crude oil, condensate, and produced water when the fluids are produced from an underground reservoir and separated or stored on the surface. The emissions are primarily a result of depressurizing the liquids from reservoir pressure to a lower surface pressure and subjecting the liquids to changes in temperature. The analysis showed that separator and tank systems with a production level of than 50 barrels of crude oil per day and less than 200 barrels of produced water do not produce enough liquids to meet the proposed emissions standard and therefore do not warrant flash emissions testing, or a permanent vapor collection system" (CARB, 2016b)**.**

However, according to CARB's *Initial Statement of Reasons* (ISOR) for oil and gas regulation, condensate tanks with a throughput of 50 barrels of crude oil or condensate per day have the potential to exceed the 10 MT of methane threshold. CARB found that "the throughput levels for systems at 10 MT of methane were 5.5 barrels of oil per day (BOPD)" (CARB, 2016a). Furthermore, when CARB conducted testing on storage vessels with a throughput of 50 BOPD, they found four of them to exceed the 10 MT of methane threshold, demonstrating that small throughput producers exempt from flash testing and emission control requirements have the potential to emit substantial amounts of methane and subsequent co-pollutants.

In an effort to determine what impact removing the small tanks producer exemptions from California's Oil and Gas Methane Regulation would have on the state's air quality, we evaluated the existing literature as it pertains to emissions from small throughput producers. According to a 2016 analysis, separator and tank systems exempt from control measures account for approximately 12% (1,088 MT) of total methane emissions reductions that could be achieved if a permanent vapor collection system were installed on all separator and tank systems under CARB jurisdiction (**Table 4.12**) (CARB, 2016b).

Table 4.12. Impact of different annual methane standards on uncontrolled systems. Source: Table 7, CARB (2016b).

Control Status	Category	# of Systems	# of Water Tanks	System Emission Reductions (MT/yr)		Water Tank Emission Reductions (MT/yr)		Total CH_4	Total CH_4
				CH_4	VOC	CH_4	VOC		
Exempt	**0 MT**	1,034	1,129	288	52	687	124	975	10.4%
	5 MT	9	9	58	10	21	4	79	0.8%
	10 MT	-	5	-	-	34	-	34	0.4%
Exempt Total		***1,043***	***1,143***	***346***	**62**	***742***	**127**	***1,088***	***11.6%***
Controlled	**15 MT**	3	8	50	-	46	-	96	1.0%
	20 MT	19	29	413	-	228	-	641	6.9%
	25 MT	2	28	58	-	372	-	430	4.6%
	30 MT	1	56	34	-	847	-	881	9.4%
	35 MT	-	69	-	-	1,266	-	1,266	13.5%
	40 MT	4	99	316	-	4,631	-	4,947	52.9%
Controlled Total		***29***	***289***	***871***	**-**	***7,390***	**-**	***8,261***	***88.4%***

Condensate and produced water tank systems are also known to be a significant source of NMVOC emissions. As stated by CARB, 10 MT of methane from a small throughput condensate or produced water tank is equivalent to ~1.8 MT/year (~2 tons/year) VOCs. Using this ratio, we found the potential NMVOC emission reductions that could be achieved if exempt sources were included in this regulation to be 189 MT of VOC annually (~208 tons/year) (**Table 4.12**). However, it is important to note that these reductions are a very small fraction of the State's total VOC inventory.

The emissions estimates do not include emissions from tanks and systems currently controlled or exempt under district rules, including those condensate tank systems regulated under SJVAPCD Rule 4623, and SCAQMD Rule 463 and Rule 1178, for example (CARB, 2016b). Each local district rule for storage vessels requires 95% vapor recovery from separator and tank systems but may have different definitions for exempt sources. Similar to state-level exemptions, *SJVAPCD Rule 4623 Storage of Organic Liquids* excludes small producers with tank throughputs of 50 barrels per day (BPD) or less from vapor collection system requirements (SJVAPCD, 2005). SCAQMD Rule 463 is more stringent, however, only exempting tanks with a monthly average throughput of less than 30 BPD of oil and only if construction occurred prior to June 1, 1984 (SCAQMD, 2011). Furthermore, these estimates were taken from a five-year-old report and may not reflect the number of exempt and non-exempt systems currently in operation in California. Therefore, the methane and subsequent NMVOC and TAC emission reductions are likely greater than what is summarized here.

The additional reduction in methane emissions and subsequent reductions in NMVOCs and TACs released from storage vessel vapor would be potentially significant if the small throughput exemption of <50 BPD of oil or condensate and <200 BPD of produced water were removed from California's statewide Oil and Gas Methane Regulation or updated to be as stringent as SCAQMD's rules. Furthermore, if local jurisdictions like the SJVAPCD also agree to remove/reduce their small throughput exemptions, the emissions reductions achieved and co-benefits to local residents could be much greater.

4.4.4. LDAR requirements: Heavy liquid exemptions and consideration of vulnerable communities

California's Oil and Gas Methane Regulation (as summarized in § 95669) includes measures related to LDAR (CARB, 2017c). Specifically, CARB's LDAR regulation requires owners and operators of oil and gas facilities (as defined in § 95666) to conduct LDAR surveys on a quarterly basis (beginning January 1, 2018) in an effort to adequately monitor oil and gas components (including components found on tanks, separators, wells, pressure vessels) for potential leaks, and repair said leaks in a timely manner (CARB, 2020b). Operators are required to submit annual LDAR reports to CARB by July 1 of each year (CARB, 2017c, 2020b).

4.4.4.1 Heavy liquid exemptions from state LDAR requirements

Components used exclusively for crude oil with an average annual API gravity of less than 20 degrees are exempt from California's Oil and Gas Methane Regulation LDAR requirements (CARB, 2017c). The API gravity scale is intended to measure the density of produced oil in relation to water. Crude oil that is heavy is more viscous and denser than what is considered to be light or medium crude oil, which typically has an API gravity of 20 degrees or more (CEC, 2020). This exemption applies to crude oil and produced water components, as well as to tank components, including pressure relief valves and pressure vacuum valves (SJVAPCD, 2019). **Figure 4.14** below provides the percentage of oil produced in California by API gravity in 2018 (CEC, 2020). As you can see, a substantial portion of oil produced in California is defined as "heavy."

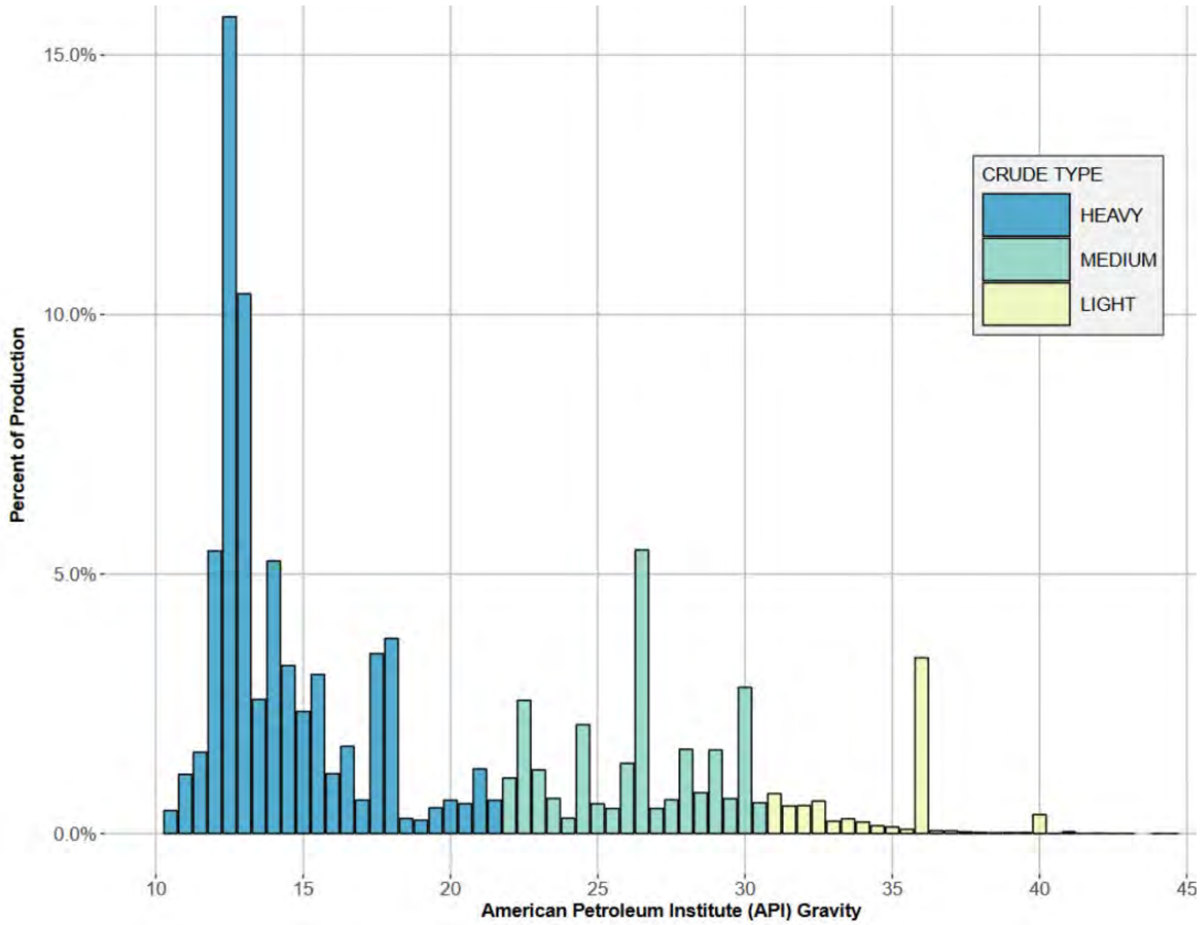

Figure 4.14. California oil field API gravity in 2018. Source: Figure from CEC (2020) analysis.

CARB states the LDAR exemption for heavy oil components is due to the fact that heavy oil (API gravity <20) emits lower levels of emissions when compared to all components subject to California's Oil and Gas Methane Regulation (CARB, 2020b). In CARB's ISOR for oil and gas, CARB states,

> "...analysis of published emission factors to date show that components associated with heavy oil emit less total hydrocarbons, and therefore less methane, than other components found in gas or other liquid service" (CARB, 2016b).

Heavy oil exemptions remain amid recent "Amendments to the Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities," which will go into effect on April 1, 2024 (CARB, 2024). CARB states that this exempt category makes up less than 1% of hydrocarbon emissions from leaking components (CARB, 2020b; 2022; CalGEM, 2023). While heavy crude oil production operations and associated components may represent a small fraction of total hydrocarbon emissions from the statewide upstream OGD sector, these emissions may be meaningful to risk of NMVOC exposure in areas with concentrated exempt infrastructure, or when this infrastructure exists in close proximity to human populations. Of note, CalGEM released a Request for Information on February 29, 2024, to seek feedback on "technologies and processes that can be used to effectively ensure leaks associated with oil and gas operations are being detected." (CalGEM, 2024)

4.4.4.2 Consideration of proximity and disproportionately impacted communities

As previously discussed in Section 4.4.2, oil and gas regions in Colorado face similar challenges to California in achieving attainment with NAAQS thresholds for ozone (CDPHE AQCC, 2021). As the oil and gas industry is the largest contributor of NMVOCs and anthropogenic methane statewide, Colorado implemented rules, including LDAR requirements, to control and reduce contributions from the oil and gas industry (CDPHE AQCC, 2021). Colorado's LDAR program, as outlined in Regulation Number 7 and updated in 2021 (IEA, 2021), is more stringent when compared to California's existing LDAR requirements, indicating that there are additional measures that could be integrated into California's current regulations to further reduce methane and associated co-pollutant emissions from the oil and gas sector.

Under Section II.E of Colorado's Regulation Number 7, well site and compressor station owners and operators must inspect components, at varying frequencies, for leaks using an approved monitoring method, and must repair identified leaks within a timely manner (CDPHE AQCC, 2021). LDAR inspection frequencies for well production facilities and gas compressor stations are established based on the magnitude of NMVOC emissions. Recent updates to this rule also require consideration of the facility's proximity to occupied areas (a residence, school, large commercial establishment, or outdoor venue) in addition to the amount of NMVOCs emitted. **Table 4.13** below provides a summary of the inspection frequency schedules for each facility type.

Table 4.13. Well production facility and gas compressor station component inspections. Source: Adapted from Table 4, Colorado Regulation Number 7, CDPHE AQCC (2021).

Well Production Facilities				
Fugitive VOC Emissions (tpy)		**Inspection Frequency**		**Phase-In Schedule**
Without Storage Tanks	**With Storage Tanks**	**Approved Instrument Monitoring**	**Audio, Visual, Olfactory**	
> 0 to < 2		One time	Monthly	January 1, 2016
≥ 2 to ≤ 12		Semi-annual	Monthly	* begins in 2020
> 2 and < 12, located within 1,000 feet of an occupied area		Quarterly	Monthly	* begins in 2020
> 12 to ≤ 20	> 12 to ≤ 50	Quarterly	Monthly	January 1, 2015
> 12, located within 1,000 feet of an occupied area		Monthly	NA	* begins in 2020
> 20	> 50	Monthly	NA	January 1, 2015
Beginning January 1, 2023				
> 0 to < 2		Annual	Monthly	January 1, 2023
> 0 to < 2, located within 1,000 feet of an occupied area		Semi-annual	Monthly	
> 0 to < 2, located in the 8-hour ozone control area and within a disproportionately impacted community		Semi-annual	Monthly	
> 2 and < 50		Quarterly	Monthly	
> 2 to < 12, located within 1,000 feet of an occupied area or within a disproportionately impacted community		Bimonthly	Monthly	
> 12, located within 1,000 feet of an occupied area or within a disproportionately impacted community		Monthly	NA	
> 20	> 50	Monthly	NA	
Natural Gas Compressor Stations				
Fugitive VOC Emissions (tpy)		**Inspection Frequency**		**Phase-In Schedule**
Without Storage Tanks	**With Storage Tanks**	**Approved Instrument Monitoring**	**Audio, Visual, Olfactory**	
> 0 to ≤ 12		Semi-annual	NA	January 1, 2015
> 12 to ≤ 50		Quarterly	NA	
> 50		Monthly	NA	
Beginning January 1, 2023				
> 0 to < 12		Quarterly	NA	January 1, 2023
> 0 to < 50, located within a disproportionately impacted community or within 1,000 feet of an occupied area		Bimonthly	NA	
> 12 to < 50		Quarterly	NA	
>50		Monthly	NA	

The updated LDAR requirements under Colorado Regulation Number 7 require more frequent inspections to be conducted for compressor stations and well production facilities located within 1,000 ft (305 m) of an occupied area or located in disproportionally impacted communities

(CDPHE, 2021).[9] For example, beginning in 2020, well production facilities emitting greater than 2 tpy of NMVOCs but less than or equal to 12 tpy (≥2 and ≤12 tpy) are required to conduct inspections semi-annually using an approved instrument monitoring method;[10] however, facilities with emissions in this same range located within 1,000 feet of an occupied area are required to conduct inspections quarterly (**Table 4.13**). Gas compressor stations and well production facility component inspections on or after January 1, 2023 are required to adhere to an even faster inspection schedule, with more inspections required on a more frequent basis for facilities located within 1,000 ft (305 m) of a well production facility and for facilities located in disproportionately impacted communities (CDPHE, 2021).

Facilities located within 1,000 ft (305 m) of an occupied area are also subject to more stringent repair timelines (CDPHE AQCC, 2021). Beginning March 2021, leaks identified at well production facilities within 1,000 ft (305 m) of an occupied area are required to either (1) repair the leak within five working days from initial discovery; or (2) follow-up with additional monitoring using EPA Method 21 within five working days from initial discovery. For facilities with leaks located outside this distance of 1,000 ft, operators are required to either (1) repair the leak within five but no later than 30 working days from initial discovery; or (2) follow-up with additional monitoring using EPA Method 21 within five working days from initial discovery. As determined by the Commission, faster repair schedules and additional monitoring is required to protect public health and the environment within these vulnerable and disproportionately impacted communities (CDPHE AQCC, 2021).

California's current local and statewide LDAR programs do not consider disproportionately impacted communities or communities in close proximity to well production facilities and gas compressor stations (CARB, 2017c). Leaks from upstream gas infrastructure represents a significant source of methane and ozone precursor emissions and LDAR requirements have demonstrated their effectiveness at mitigating off-normal NMVOC releases from the oil and gas industry. While California's existing LDAR program does much to reduce emissions from this sector, examples of other state LDAR policies indicate that it is possible for California to do more to further reduce large off-normal releases of methane and NMVOCs, especially for those communities near upstream sites and who are disproportionately health burdened. As such, California LDAR policies could consider implementing more stringent inspection, monitoring, and repair requirements for upstream oil and gas production facilities located closed to populations or located within disproportionately burdened communities.

[9] Disproportionately impacted communities are defined by the Colorado Environmental Justice Act (HB21-1266) as census block groups where greater than 40% of households are (1) low income, (2) housing cost-burdened, or (3) include people of color.

[10] An alternative to the list of approved air monitoring methods includes non-quantitative monitoring, e.g., infrared cameras and/or audio, visual, olfactory (AVO) methods. However, for operators implementing these alternative monitoring methods are required to conduct monthly inspections, however, and are subject to more stringent repair requirements.

4.4.5. Summary of findings

Enforced vapor recovery and LDAR regulations provide tools to enhance detection and reductions of emissions of methane and NM VOCs, including TACs and ozone precursors to the atmosphere. In California, regulatory exemptions from vapor recovery, LDAR, and equipment change-out requirements have been established based on methane and NMVOC emissions from specific upstream oil and gas sources. These exemptions include, but are not limited to (1) a statewide zero-bleed/zero-emission standards exemption for existing low-bleed (<6 standard cubic feet per hour) natural gas-driven pneumatic devices installed prior to January 1, 2016; 2) an exemption from the statewide 95% vapor recovery requirement for low-throughput separators and condensate tank systems; and (3) an exemption from the statewide leak detection and repair (LDAR) requirement for upstream oil and gas infrastructure components associated with heavy oil (API gravity <20).

The closure of the exemptions from statewide zero-bleed/zero-emission standards for existing low-bleed pneumatic devices and vapor recovery requirements for low-throughput separators and condensate tank systems would reduce NMVOC emissions by an estimated 15 tpy from 50 existing natural gas powered pneumatic devices and 208 tpy from ~2,200 small throughput separator and tank systems. Additionally, the California Air Resources Board states that heavy oil components (API gravity <20) exempt from LDAR account for less than 1% of hydrocarbon emissions from leaking components. While these exemptions represent a small fraction of NMVOC emissions from the statewide upstream oil and gas development sector, these emissions may be meaningful to risk of NMVOC exposure in areas with concentrated exempt infrastructure or when this infrastructure exists in close proximity to human populations

4.5. Discussion

Findings suggest that emissions from upstream oil and gas may significantly impact regional air quality within specific regions of California, such as the San Joaquin Valley. In regions where upstream OGD is one of several sources of the regional ambient air pollution, such as the South Coast Air Basin, emissions from upstream OGD sites still pose a local risk to residents and other nearby sensitive populations (e.g., schools, playgrounds, community centers) due to local increases in pollutants associated with active oil and gas production. The cumulative burden of air pollution from oil and gas in addition to other pollution sources may exacerbate health risks.

The status of California's oil and gas producing regions under federal air quality regulations is relevant in thinking about the potential impacts from upstream OGD. The majority of the state's oil and gas producing regions are in nonattainment for ozone NAAQS, with upstream oil and gas contributing to these regions' nonattainment status. In the South Coast region, upstream OGD contributions are minimal when compared to all sources; in the San Joaquin Valley, emissions contributions are significant. Further, a 2018 federal rule on TAC emissions allows major industrial sources to reclassify as area sources and potentially increase their TAC emissions. Many such facilities lie within California's oil and gas producing regions. One study found that in the San Joaquin Valley, 13 major sources of TACs could potentially increase emissions by 300 tpy total and in the Los Angeles area 15 facilities could potentially increase TACs by a total of 345 tpy (Declet-Barreto et al., 2020). These findings suggest more could be done to control emissions in these regions.

Methane and NMVOCs are emitted during upstream oil and gas development. Many of the NM VOCs emitted are TACs or ground-level ozone precursors. Because both methane and some NMVOCs have a common source, certain infrastructure components, such as wellheads, gas pipelines, and gas processing plants, have emission profiles with high methane:non-methane hydrocarbon ratios. However, other components, such as condensate tanks and produced water ponds, have emission profiles with far lower methane:non-methane hydrocarbon ratios, and methane is not a reliable indicator of NMVOCs that are not hydrocarbons. While diesel engines used for transport, pumps, and other purposes do not emit methane and have a zero methane:non-methane hydrocarbon ratio, they do emit criteria air pollutants (CAPs), TACs, and other air pollutants.

Results demonstrate a clear decline in methane (Collier-Oxandale et al., 2020; Okorn et al., 2021), benzene, and alkane emissions (Garcia-Gonzales et al., 2019b) as distance from oil and gas production increases. For example, in one study, benzene levels were highest 427 ft (130 m) from activity, and levels of n-hexane and n-pentane (alkanes) were highest 640 ft (195 m) and 542 ft (165 m) away, respectively (Garcia-Gonzales et al., 2019b). An important implication from this assessment is that significant reductions in methane could translate to potentially significant reductions in TACs and ozone precursors emissions (e.g., NMVOCs), beyond what is currently being achieved in California.

Studies conducted on oil and gas development outside of California identified several NMVOCs, including TACs such as n-hexane, benzene, ethylbenzene, toluene, and xylenes, as methane co-pollutants. Significant correlations were also found among emissions of benzene and toluene, benzene and m- & p-xylene, and toluene and m- & p-xylene. Many of the NMVOCs identified as methane co-pollutants in other oil and gas producing states have been detected in emissions from, and atmospheric concentrations near, upstream oil and gas development in California (e.g. benzene, toluene, ethylbenzene, xylenes, alkanes).

LDAR focused on monitoring for methane is useful when monitoring equipment with emissions that have high methane:non-methane hydrocarbon ratios. In this context, methane can be a reasonable indicator of the presence of TACs and other NMVOCs that are intermixed with methane. However, when monitoring emissions from infrastructure or processes containing gases with low methane:non-methane ratios (e.g., condensate tanks, produced water management and disposal, etc.) or little to no methane content (e.g., combustion from diesel engines, combustion emission from natural gas-powered equipment, etc.), methane is not a reliable indicator of TAC and other NMVOC emissions and there is likely no surrogate for these situations. LDAR approaches that focus on measurement of large suites of air pollutant species may be more comprehensive and appropriate for various applications when gas composition is uncertain.

In California, regulatory exemptions from vapor recovery, LDAR, and equipment change-out requirements have been established based on methane and NMVOC emissions from specific upstream oil and gas sources. These exemptions include, but are not limited to (1) a statewide zero-bleed/zero-emission standards exemption for existing low-bleed (<6 standard cubic feet per hour) natural-gas driven pneumatic devices installed prior to January 1, 2016; (2) an exemption from the statewide 95% vapor recovery requirement for low-throughput separators and condensate tank systems; and (3) an exemption from the statewide leak detection and repair (LDAR) requirement for upstream oil and gas infrastructure components associated with heavy oil (API gravity <20). While exemptions represent a small fraction of NMVOC emissions from the statewide upstream OGD sector (Section 4.4), these emissions may be meaningful to risk of NMVOC exposure in areas with concentrated exempt infrastructure or when this infrastructure exists in close proximity to human populations.

Studies conducted outside California identified ethane, hexane, pentane, heptane, butane, and benzene as methane co-pollutants. Significant correlations were also found among emissions of benzene and toluene, benzene and m- & p-xylene, and toluene and m- & p-xylene. While not specific to California, many of the compounds identified as co-pollutants of methane in other oil and gas producing states have also been detected in emissions from upstream OGD in California (e.g., BTEX, alkanes).

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Appendix D

D.1 Chemical usage in upstream OGD in California with respect to airborne exposure

Chemical additives used in upstream OGD can volatilize and have the potential to increase airborne exposure of surrounding communities to potentially hazardous chemicals depending on the location and distribution of upstream oil and gas operations. Characterizing chemical additives using physical and chemical properties such as boiling point, Henry's law constant, and atmospheric oxidation half-life can be useful for comparing the potential for exposure via airborne pathways.

Chemical volatility describes the likelihood that a chemical will vaporize from a solid or liquid state and is useful for screening chemicals regarding their mobility and potential for airborne exposure. Organic chemical additives were classified as either very volatile, volatile, or semi-volatile according to boiling point categorizations for VOCs (aka NMVOCs) adapted from the U.S. EPA and the World Health Organization (WHO) (see Table D.2) (US EPA OAR, 2014; WHO, 1989). Organic chemicals with boiling points greater than 400°C were considered non-volatile for categorization purposes.

Henry's law constant provides an indication of chemical volatility from water sources, such as drilling or hydraulic fracturing fluids, produced water ponds, and storage tanks. Organic chemical additives were classified as either very volatile, volatile, moderately volatile, slightly volatile, or non-volatile from water according to generalized categorizations for Henry's law constant provided in Table D.2. To provide a conservative estimate, if a chemical was classified as semi-volatile, volatile, or very volatile based on boiling point or classified as slightly volatile, moderately volatile, volatile, or very volatile based on Henry's law constant, the chemical is considered volatile for the sake of this analysis.

In addition to volatility, atmospheric oxidation half-life can be used as a metric for determining the persistence of chemicals in the atmosphere and the potential for long-range transport and airborne exposure. Atmospheric oxidation half-life due to hydroxyl radicals (OH) was calculated using OH rate constants according to the following equation:

$$\text{Atmospheric oxidation half-life} = \ln(2)/(\text{OH rate constant} * \text{concentration of OH radicals})$$

using a standard OH concentration of 1.5×10^6 OH radicals cm^{-1} and converted to hours. Data regarding hydroxyl radical rate constants were generally more available than ozone and nitrate rate constants. When data for both OH and ozone rate constants were available, atmospheric oxidation half-lives due to OH were generally shorter, indicating OH radicals are likely the primary method of atmospheric oxidation for the investigated chemical additives. Atmospheric half-life due to OH radicals were categorized according to Table D.2 using a 12-hour day due to the formation of OH radicals during daylight hours and negligible oxidation during the night.

When experimental boiling point data, Henry's law constant, or OH rate constant values were not available, estimates from EPI Suite™ MPBPWIN™, HENRYWIN™, and AOPWIN™ modules were used, respectively. Classification of organic chemicals according to volatility and atmospheric half-life is provided in Table D.1.

Table D.1. Categorization of organic chemicals used in upstream OGD in California by volatility, based on boiling point and Henry's law constant, and atmospheric half-life.

Volatility Category	Number of Chemicals	Atmospheric Oxidation Half-Life (OH)	
		Time frame*	Number of Chemicals
Very Volatile	63	≤ 2 h	4
		2 h–1 d	33
		>1 d	24
		No data	2
Volatile	115	≤ 2 h	18
		2 h–1 d	53
		>1 d	33
		No data	11
Semi-volatile, moderately volatile, or slightly volatile	54	≤ 2 h	15
		2 h–1 d	17
		>1 d	16
		No data	6
Non-volatile	112	≤ 2 h	63
		2 h–1 d	38
		>1 d	12
		No data	0
No data	134	≤ 2 h	1
		2 h–1 d	1
		>1 d	0
		No data	132

*Atmospheric half-life timeframes are grouped according to categories in Table D.2.

A total of 232 chemical additives (out of 630) are considered very volatile, volatile, semi-volatile, moderately volatile, or slightly volatile based on boiling point or Henry's law constant categorization. A total of 176 out of the 232 chemicals have slow to moderate atmospheric oxidation rates (>2 hours, see Tables D.2), indicating increased potential for atmospheric transport and subsequent airborne exposure. A total of 152 chemicals were inorganic and were not assessed in this analysis.

OECD P_{ov} & LRTP Screening Tool and Chemical Screening for Potential Airborne Hazard

Chemical additives were characterized for long-range transport potential (LRTP) and overall persistence (P_{ov}) using the Organization for Economic Co-operation and Development (OECD) P_{ov} & LRTP Screening Tool (The Tool). The Tool and the accompanying manual can be downloaded from the OECD's website (OECD, 2009). More information about The Tool can be found in Wegmann et al. (2009).

Briefly, the Tool is a fugacity-based steady-state multimedia mass balance model that was developed to estimate overall environmental persistence and long-range transport potential of organic chemicals at a screening level to support decision-making for chemical management (OECD, 2009; Wegmann et al., 2009). The Tool utilizes a unit-world model and takes into account chemical partitioning between air, soil, and sea compartments. For our purposes, the characteristic travel distance (CTD) is the LRTP metric used to compare chemical additive mobility, and is defined as the distance from a point release to where the concentration is 1/e or 37% of the initial value (Wegmann et al., 2009). P_{ov} is a measure of the degradation time scale for a given chemical in the whole environment (Wegmann et al., 2009). In addition to calculating combined whole environment scores, individual CTD and P_{ov} are also calculated for air, soil, and seawater emission scenarios separately.

The Tool requires five physicochemical inputs: log K_{aw}, log K_{ow}, and estimated half-lives in air, water, and soil (OECD, 2009). Log K_{aw} was calculated using Henry's law constant values. When experimental values for Henry's Law constant and log K_{ow} were not available, estimates from EPI Suite™ HENRYWIN™ and KOWWIN™ modules were used, respectively. Half-life in air was calculated using atmospheric oxidation half-life due to hydroxyl radicals as previously described. Half-life in water and soil were estimated using the EPI Suite™ BIOWIN™ module. Results from the BIOWIN3 model for ultimate biodegradation in aerobic aqueous environments were assigned half-lives based on conversions utilized in other studies and frameworks (Aronson et al., 2006; Scheringer et al., 2006; Scheringer, 2010; US EPA, 2012). Some studies use the EPI Suite™ BIOWIN4 model for primary biodegradation to estimate the half-life in water (Rogers et al., 2015); we used ultimate biodegradation because it represents a more conservative approach. Half-life in soil is assumed to be the same as the half-life in water based on U.S. EPA guidance (US EPA, 2020c). Estimations from EPI Suite™ models, such as BIOWIN™, AOPWIN™, KOWWIN™, KOAWIN™, and HENRYWIN™ are generally accepted by US regulatory authorities when experimental data are unavailable (Rücker & Kümmerer, 2012) and are widely used by the scientific community as inputs for modeling the environmental fate of chemicals when experimental data is unavailable (Aronson et al., 2006; Gouin & Harner, 2003; Rücker & Kümmerer, 2012; Scheringer, 2010; Scheringer et al., 2006; Sühring et al., 2020; Wania & Dugani, 2003). The Tool is inappropriate for the characterization of acids, bases, metals, inorganic, and ionizing compounds (Wegmann et al., 2009).

Using the outputs from The Tool, chemical additives were ranked according to potential hazard for airborne exposure based on the chemical screening methodology adapted from Yost et al. (2017). Briefly, chemicals were assigned three scores based on inhalation toxicity, occurrence, and physicochemical properties. For our purposes, the cancer inhalation toxicity score is based on inhalation unit risk factors, while the non-cancer inhalation toxicity score was based on chronic inhalation reference concentrations (RfC) and minimal risk levels (MRLs). The occurrence score is determined by the frequency of use of a chemical in available chemical disclosure databases. Mass data was not used due lack of availability and uncertainty in the underlying data; chemical concentrations would often add up to >100% in the FracFocus dataset. Chemicals only reported in the AB 1328 dataset did not have any frequency of use data available and could not be given an occurrence score (CVRWQCB, 2021). The physicochemical properties score was determined by summing three separate scores for volatility (based on boiling point), persistence (based on P_{ov} for air emission), and mobility (based on CTD for air emissions). Each individual score was rated from 1 to 4 based on either quartiles (e.g., toxicity) or threshold values (see Table D.3) and summed together to determine the physicochemical properties score. The scores for toxicity, occurrence, and physicochemical properties were standardized within each subset of chemicals from a scale of 0 to 1, and all three scores were summed together to determine relative total hazard potential score. Because each score is relative to other compounds, only chemicals with data available to calculate all three scores were evaluated.

As shown in Table D.4, chemicals that were frequently reported in oil and gas chemical additive disclosures were consistently ranked high for potential hazards compared to other additives. Highly toxic chemicals that were rarely reported in oil and gas operations, such as benzyl chloride and acrylonitrile, were still ranked high due to their environmental persistence and mobility. Other chemicals with relatively low toxicity but which were the most frequently reported, such as methanol and isopropanol, and were also ranked high due to environmental persistence and mobility. BTEX compounds were not grouped together due to relative differences in frequency of use and non-cancer toxicity. Cancer based hazard rankings generally favored chemicals with higher inhalation unit risk values, even if they were infrequently reported (Table D.5). The BTEX compounds benzene and ethylbenzene ranked surprisingly low due to their relatively low inhalation unit risk values compared to other chemical additives.

The major limitation of this approach is the availability of physicochemical and toxicity data required to evaluate chemicals. In total, only 23 chemical additives had all the required data for evaluation. Toxicity data was the biggest limiting factor, with only 43 and 18 chemicals having non-cancer and cancer inhalation toxicity information, respectively, out of 630 chemical additives. Because the vast majority of chemical additives were missing data and could not be evaluated, it is difficult to draw conclusions about the relative hazards of upstream chemical usage. Additional data on chronic inhalation toxicity and cancer unit risks would aid in the evaluation of potential hazards associated with airborne exposure to chemicals used in upstream oil and gas activities.

Table D.2. General interpretation of various chemical properties in the context of mobility and hazard assessment. Sources: US EPA (2012); US EPA OAR (2014).

Chemical property	Value	Generalized Classification
Henry's Law Constant (atm-m^3/mole)	$>10^{-1}$	Very volatile from water
	10^{-1}–10^{-3}	Volatile from water
	10^{-3}–10^{-5}	Moderately volatile from water
	10^{-5}–10^{-7}	Slightly volatile from water
	$<10^{-7}$	Non-volatile
Log K_{ow}	<1	Highly soluble in water (hydrophilic)
	>4	Not very soluble in water (hydrophobic)
	>8	Not readily bioavailable
	>10	Not bioavailable - difficult to measure experimentally
	2–4	Liquids tend to absorb well through the skin
	>4	Chemical tends to not absorb well through skin
	5–6	Chemical tends to bioconcentrate in the lipid portion of the membrane
Atmospheric oxidation half-life	<2 hours	Rapid oxidation
	2 hrs–< 1 day	Moderate oxidation
	1–10 days	Slow oxidation
	>10 days	Negligible oxidation
	>2 days	Potential for long range transport in air
Boiling Point	<0 to 50–100°C	Very volatile
	50–100 to 240–260°C	Volatile
	240–260 to 380–400°C	Semi-volatile

Table D.3. Threshold values used to rank physicochemical properties for screening potential airborne exposure of chemicals

Chemical Property	Value	Ranking value
P_{OV} for air emissions (days)	>100	4
	10–100	3
	1–10	2
	<1	1
CTD for air emissions (km)	>100	4
	10–100	3
	1-10	2
	<1	1
Boiling point (°C)	<0 to 50–100	4
	50–100 to 240–260	3
	240–260 to 380–400	2
	>400	1
Non-cancer inhalation reference concentration (mg/m^3)	≤1st quartile	4
	>1st quartile to ≤2nd quartile	3
	>2nd quartile to ≤3rd quartile	2
	>3rd quartile	1
Cancer inhalation unit risk $(ug/m3)^{-1}$	≥3rd quartile	4
	≥2nd quartile to <3rd quartile	3
	≥1st quartile to <2nd quartile	2
	<1st quartile	1
Number of disclosures	≥3rd quartile	4
	≥2nd quartile to <3rd quartile	3
	≥1st quartile to <2nd quartile	2
	<1st quartile	1

Table D.4. Chemical additives ranked according to relative potential hazard via airborne exposure using relative non-cancer toxicity, occurrence, and physicochemical scores.

Chemical Name	CASRN	Physico-chemical Score	Occurrence Score	Non-Cancer Toxicity Score	Overall Score
Formaldehyde	50-00-0	0.75	1	0.66	2.41
Naphthalene	91-20-3	0.25	1	1	2.25
Isopropanol	67-63-0	0.75	1	0.33	2.08
Ethylbenzene	100-41-4	0.5	1	0.33	1.83
Methanol	67-56-1	0.75	1	0	1.75
Acrylonitrile	107-13-1	0.75	0	1	1.75
Benzyl chloride	100-44-7	0.75	0	1	1.75
Benzene	71-43-2	0.75	0.33	0.66	1.75
Xylenes	1330-20-7	0.25	1	0.33	1.58
Acrylamide	79-06-1	0.5	0	1	1.5
Cumene	98-82-8	0.5	0.66	0.33	1.5
Acetone	67-64-1	1	0.33	0	1.33
1,2,4-Trimethylbenzene	95-63-6	0	0.66	0.66	1.33
Diethylene glycol mono-n-butyl ether	112-34-5	0.25	0	1	1.25
2-Butoxyethanol	111-76-2	0.25	0.66	0.33	1.25
1-Methoxy-2-propanol	107-98-2	0.5	0.66	0	1.16
Toluene	108-88-3	0.5	0.66	0	1.16
Diethanolamine	111-42-2	0	0	1	1
1,2,3-Trimethylbenzene	526-73-8	0	0.33	0.66	1
1,3,5-Trimethylbenzene	108-67-8	0	0.33	0.66	1
Isobutylmethylcarbinol	108-11-2	0.25	0.33	0	0.58
Methyl isobutyl ketone	108-10-1	0.25	0	0	0.25

Table D.5. Chemical additives ranked according to relative potential hazard via airborne exposure using relative cancer toxicity, occurrence, and physicochemical scores

Chemical Name	CASRN	Physicochemical Score	Occurrence Score	Cancer Toxicity Score	Overall Score
Ethylene oxide	75-21-8	1	0.33	1	2.33
Formaldehyde	50-00-0	0.66	1	0.33	2
Acrylamide	79-06-1	0.33	0.33	1	1.66
Acrylonitrile	107-13-1	0.66	0	0.66	1.33
Benzyl chloride	100-44-7	0.66	0	0.66	1.33
Naphthalene	91-20-3	0	1	0.33	1.33
Benzene	71-43-2	0.66	0.66	0	1.33
Ethylbenzene	100-41-4	0.33	0.66	0	1

D.2 Interpreting cancer and non-cancer health risks

Interpreting non-cancer health risk

Hazard quotients and hazard indices are used to estimate noncancer health risks associated with acute and chronic exposures. A hazard quotient (HQ) is the ratio between the estimated or observed exposure concentration and a health guidance value for a given chemical. It is often assumed in risk assessment that exposures at or below the health guidance value (i.e., HQs of 1 or less) are of less concern for adverse non-cancer health effects. Additionally, exposures at or below the health guidance value (i.e., HQs of 1 or less) are not likely to be associated with adverse health effects. It must be noted, however, that in reality, non-cancer endpoints (e.g., infertility, pregnancy complications, birth defects, neurodevelopmental delays, metabolic disorders, and cardiovascular disease) may also have non-threshold dose response relationships due to population variability in response (NRC, 2009). However, as exposures increase above the health guidance value (i.e., HQs are greater than 1), the potential for adverse effects increases. To consider exposure from multiple air pollutants, acute and chronic hazard indices (HI) are calculated by summing HQs for individual compounds that are anticipated to affect the same target organ system based on acute or chronic exposure duration. Target organ systems can include the respiratory system, hematologic system, alimentary system, endocrine system, growth and development, reproductive system, nervous system, cardiovascular system, skin, eyes, and general toxicity (OEHHA, 2015a).

Interpreting cancer risk estimates

In California and per requirements of Assembly Bill 2588 (the Air Toxics "Hot Spots" Information and Assessment Act), the Office of Environmental Health Hazard Assessment (OEHHA) and CARB are responsible for providing local air districts guidance on the preparation of health risk assessments for stationary sources with the potential to emit TACs (TACs) (OEHHA, 2015b). AB 2588, enacted in 1987, requires stationary sources to report the types and quantities of TACs emitted routinely from a given facility in an effort to reduce significant risks to “acceptable” levels (OEHHA, 2015a).

SJVAPCD utilizes the following action thresholds with respect to stationary source permitting:

- For each permitted unit that exceeds the 1 in one million excess cancer risk threshold, installation of toxic best available control technology (T-BACT) is required.
- If the cumulative cancer risk for the facility exceeds 20 in a million excess cancers, the permit for the project will be denied (SJVAPCD, 2015).

Similarly, the SCAQMD establishes requirements that must be met before a permit can be issued. Risk assessment guidance for equipment subject to Rules 1401, 1401.1, and 212 states:

“The cumulative increase from all TACs emitted from a single piece of equipment in MICR shall not exceed:

- 1 in one million (1.0 x 10-6 or 1E-06) if toxic best available control technology(T-BACT) is not used; or,
- 10 in one million (10 x 10-6 or 10E-06) if T-BACT is used (SCAQMD, 2015c).

Additionally, SCAQMD Rule 1402 defines the “Action Risk Level” as greater than or equal to 25 in one million excess cancer risks and the “Significant Risk Level” as greater than or equal to 100 in one million excess cancer risks (SCAQMD, 2020). In both cases, Risk Reduction Plans are required to be submitted to the District within a certain time frame, and must be implemented within 2–2 ½ years. Excess cancer risk levels for the two top oil and gas producing air districts in California are described in more detail in Table D.6.

Table D.6. Excess cancer risk levels and interpretation for two top oil and gas producing air districts in California.

Air District	Significant Cancer Risk Threshold	Interpretation	Source
SCAQMD *Rules 1401, 1401.1 & 212*	**>1 in one million**	T-BACT is required.	SCAQMD (2015c)
	>10 in one million	Tier 3 or 4 more detailed analysis required before permit can be issued.	
SCAQMD *Rule 1402*	**≥25 in one million**	120 days to submit a Risk Reduction Plan; three months for the District to approve the Plan; No later than 2.5 years to implement the Plan.	SCAQMD (2020)
	≥100 in one million	90 days to submit an Early Action Reduction Plan; 180 days to submit a Health Risk Assessment and/or Risk Reduction Plan; No later than two years to implement the Plan.	
SJVAPCD *APR 1905*	**>1 in one million**	T-BACT is required.	SJVAPCD (2015)
	>20 in one million *significance threshold*	Not approvable. Additional controls or alternative design needs to be applied.	

CHAPTER FIVE

Potential Impact to Public Health from the Management and Disposal of Produced Water

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5.0 Abstract

In this chapter, the disposition, chemistry, and potential contamination and/or exposure pathways of produced water from oil and gas industry operations in the state of California are examined. Both the production volumes and disposal methods of produced water during the period of 1977–2017 were examined. In general, produced water generation in California has been increasing since the mid-1990s, and the majority is disposed of via subsurface injection. However, the multiple reporting systems of produced water disposal introduce uncertainty in quantifying exact volumes of disposed water.

This chapter also characterizes the chemistry of produced waters in California, providing a relatively comprehensive assessment of constituents found in produced waters. However, there is considerable heterogeneity in the analysis requirements across both regulatory programs and geographic areas. Thus, despite being well known to contain potentially harmful compounds (e.g., benzene, toluene, arsenic), the exact composition of produced water, and organic compounds in particular, is not explicitly regulated. For example, in the southern San Joaquin Valley, produced water was commonly disposed of in unlined earthen ponds from the early 20th century until 2014. Comprehensive chemical analyses of these waters were relatively rare prior to 2015, and few studies have examined airborne emissions of organic compounds from these ponds. An analysis of chemical data contained in the State Water Resources Control Board Geotracker system indicates that waters contained in disposal ponds exceed Tulare Basin effluent limits in at least 75% of samples, and often contain contaminants (e.g., benzene, radium) at concentrations that exceed California Maximum Contaminant Levels. Despite sparse groundwater monitoring near these facilities, recent work has demonstrated that the disposal of produced water via this method has impacted groundwaters over 4 km (2.5 mi) from disposal facilities, and most commonly more than 1 km (3,281 ft). Approximately 545,000 (~1 in 75) Californians live within 1 km (3,281 ft) of an active, inactive, or historical produced water pond.

An extensive review of onshore oil and produced water spills in California was also conducted, indicating that there were 1,029 incidents involving a spill of produced water. However, despite the potential threat to environmental and human receptors, significant knowledge gaps surrounding these incidents appear to exist. Specifically, only approximately 6% of incidents involving a spill of crude oil or produced water contained geographic coordinates, greatly hindering assessing the potential impacts of these events to public health. Moreover, updated spill volumes are not rapidly retrievable from the database maintained by the California Office of Emergency Services, and during the years 2018–2020 volumes of produced water spilled were underreported ranging from 35–2,750%. It is unclear if groundwater monitoring is performed following spill events.

5.1. Overview

Wastewater from oil and gas development (OGD) is commonly referred to as produced water. Produced water is generated during several oil and gas exploration and production activities, including drilling through saline groundwater that overlies target oil and gas reservoirs; stimulation of oil or gas reservoirs by hydraulic fracturing; workover (i.e., well maintenance) operations; and day-to-day production and operations (GWPC, 2019). In the state of California, about 20% of all produced waters come from stimulated (hydraulic fracturing, matrix acidizing) reservoirs (Stringfellow et al., 2015).

Produced water is considered waste from oil and gas exploration and production and is thus excluded from hazardous waste classification under Subtitle C of the Resource Conservation and Recovery Act (RCRA) (US EPA, 2002). Operators employ numerous methods to dispose of this waste, and in Section 5.2 the volumes of produced water disposed of via various methods are discussed.

The chemical characteristics of produced water depend on the geographic location of the field, the geological formation in which groundwater resides, and the hydrocarbon being extracted (GWPC, 2019). For example, produced waters vary greatly in salinity (GWPC, 2019). In addition, produced water commonly contains many toxic organic and inorganic compounds. Some of these are naturally occurring dissolved or emulsified hydrocarbons, while others are related to chemicals added for well control or reservoir stimulation purposes. While produced waters from shale reservoirs (e.g., the Marcellus Shale) are relatively enriched in radionuclides, radionuclide levels in Californian produced waters are significantly lower (McMahon et al., 2019).

A number of factors can influence the chemistry of produced water including but not limited to: hydrocarbon field setting and petroleum geology; geologic history; flushing of meteoric water; confining geologic layers; history of oil and gas activities and water injection; current and historical downhole chemical use; and field temperature and pressure (Clark & Veil, 2009; Kahrilas et al., 2015; McMahon et al., 2018). Chemical constituents that are or may be in produced water include residual petroleum hydrocarbons, chemical additives, geogenic compounds, and degradation byproducts of chemical transformations. Operators have few, if any, restrictions on the chemicals used for conventional and unconventional OGD in California. Section 5.3 contains a detailed discussion of the chemistry of produced water, and Section 5.5.3 describes the chemical composition of produced waters contained in disposal ponds in the California.

Multiple strategies are used to dispose of produced water. This chapter provides a discussion of California's produced water generation, disposal, and chemistry, along with possible environmental contamination pathways due to produced water disposal methods (**Figure 5.1**).

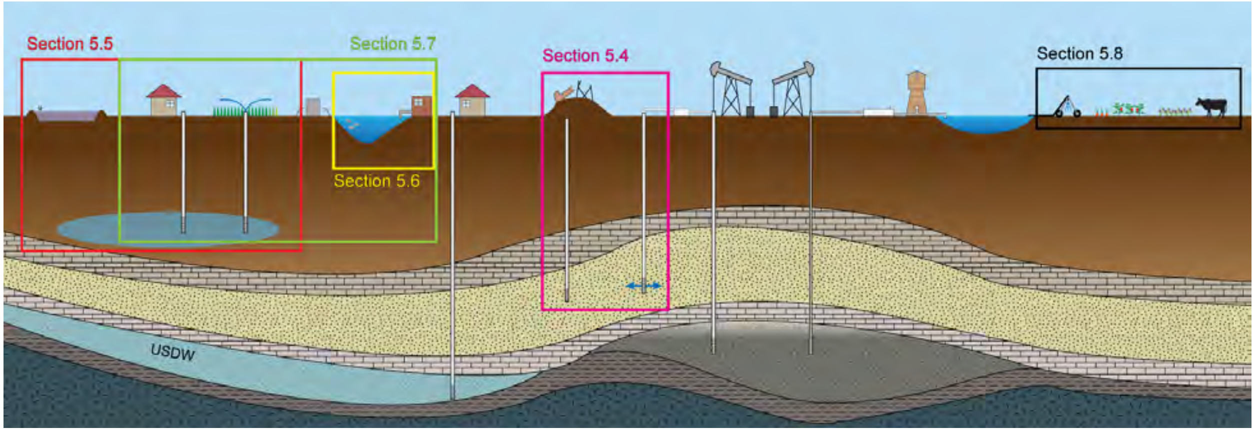

Figure 5.1. Conceptual model of the potential contamination and exposure pathways from the generation and use of produced water in California. Inset boxes indicate the sections where detailed conceptual models and discussion of specific activities are located.

5.2. Produced Water Volumes and Disposition

The long-term trends of produced water generation and disposal in California are tied to the amount and type of oil and gas activities. In 2017, California ranked second only to Texas in produced water generation, was tied with New Mexico for fourth place in oil production (behind Texas, North Dakota, and Alaska), and was 15th in natural gas production (Veil, 2020). Remaining oil reserves in California are mostly heavy crude, which largely requires energy-intensive enhanced oil recovery (water flooding and steam injection) for removal and generates large quantities of produced water (Alvarado & Manrique, 2010).[1]

To determine long-term trends of produced water disposal in California, data files from the California Geologic Energy Management Division's (CalGEM) Well Production and Injection Summary Reports were downloaded for the years 1977 (year of earliest electronic availability) to 2017. The reports indicate the generation of produced water in California has been increasing since 1994, while oil and gas production has been decreasing since 1985, thus resulting in an increasing ratio of produced water to oil volumes (**Figure 5.2**).

In California, subsurface injection is the most common method of produced water management (**Figure 5.3**), accounting for a low of 40.3% and a high of 84.5% of produced water in 1981 and 2017, respectively. In both CalGEM's Well Production and Injection Summary Reports and reporting pursuant to Senate Bill (SB) 1281 (Pavley, 2014), injection for enhanced oil recovery is not distinguished from injection into wells for disposal. However, Veil (2020) estimates that most (~73%) injected water in California is used for enhanced oil recovery. CalGEM does not provide a definition of "Not Applicable" in Well Production and Injection Summary Reports.

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[1] Enhanced oil recovery wells are used to prolong the productive life of wells within a specific oil field. Secondary recovery is an enhanced oil recovery process commonly referred to as water flooding.

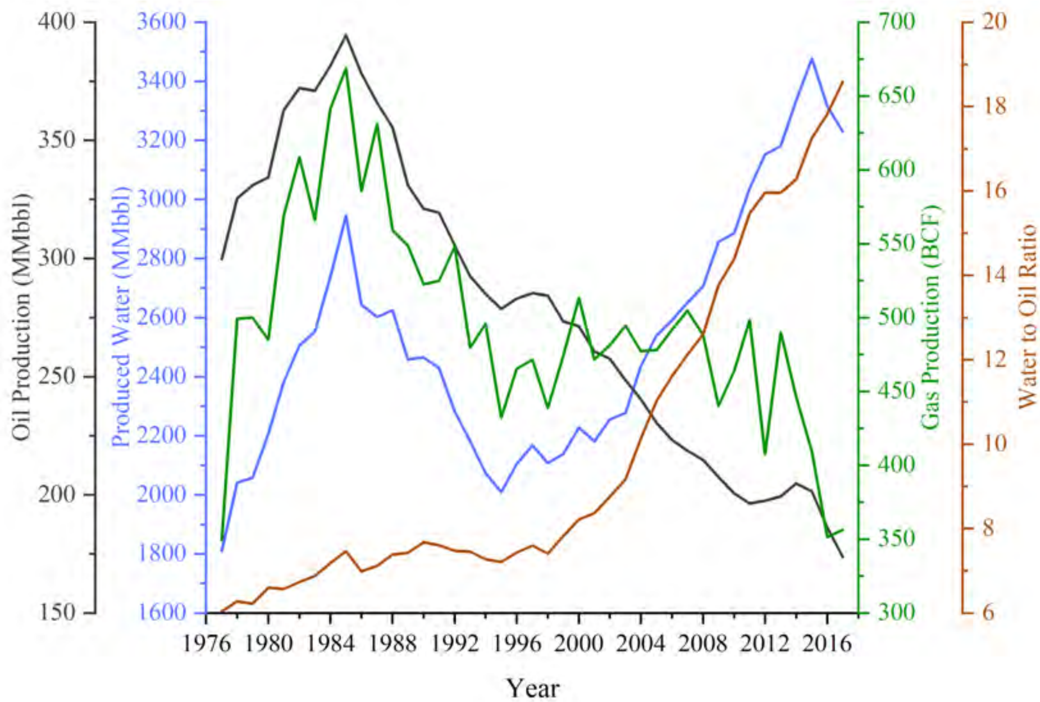

Figure 5.2. Plot of oil production in millions of barrels (MMbbl), gas production in billions of cubic feet (BCF), produced water generation (MMbbl), and water to oil ratio from 1977 to 2017 as reported to CalGEM. Source: Figure S2 from DiGiulio et al. (2021).

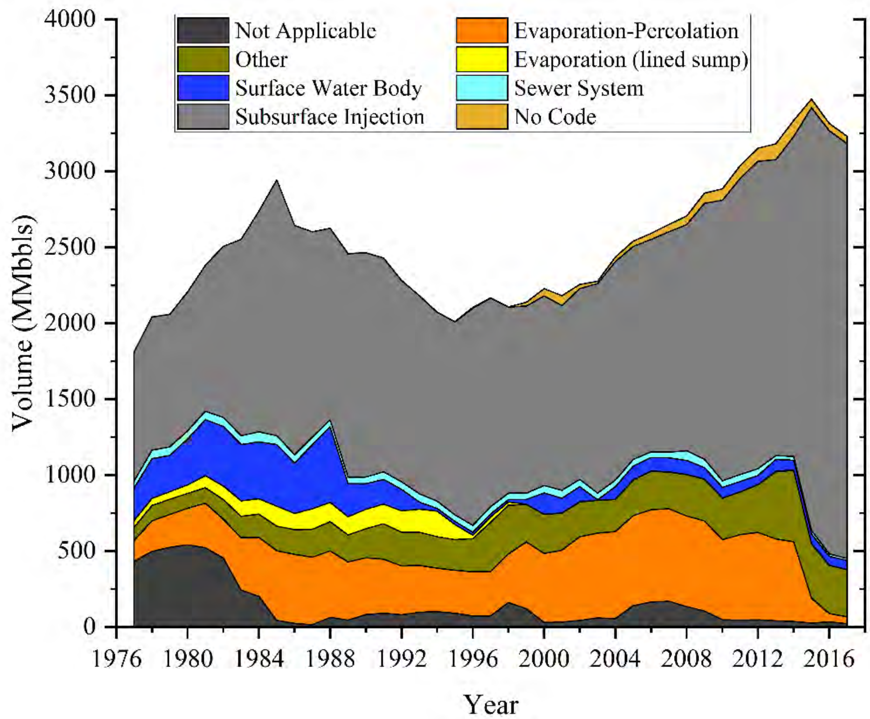

Figure 5.3. Stacked area plot of produced water disposition from 1977 to 2017 as reported to CalGEM. Data from CalGEM Well Production and Injection Summary Reports. Source: Figure S3 from DiGiulio et al. (2021).

The multiple reporting systems of produced water disposal in California appear to create uncertainty regarding the volumes of produced water disposed via specific methods. As such, it is possible that actual volumes of produced water disposed via a particular method exceed reported volumes for said method. For example, both the “Other” disposition category in the CalGEM Well Production and Injection Summary Reports and reporting pursuant to SB 1281 contain an “Other” category which includes commercial disposal. However, because commercial water disposal companies also dispose of produced water into unlined ponds, the “Other” category in both reporting systems could also include disposal to unlined produced water ponds. Hence, actual disposal volumes into unlined produced water ponds could be greater than represented under both reporting systems and further assessment is needed to confirm this one way or another. It should also be noted that for those ponds that are under orders from the Central Valley Regional Water Quality Control Board (CVRWQCB), operators are required to submit volume information to the CVRWQCB.

5.3. Chemical Characterization of Produced Water

Requirements for analysis of produced water in California largely depend on the regulatory program and geographic area where storage or disposal of produced water occurs. Some requirements for chemical characterization are statewide, whereas others are regional. Logically, the stringency and scope of requirements for chemical characterization of produced water should be dependent on potential exposure pathways to human or ecological receptors.

Following the enactment of SB 4, an analysis of produced water during the first three well volumes of flow and after 30 days of operation at stimulated production wells is required (**Table 5.1**) (14 C.C.R. § 1788, 2015). While many commonly reported water chemical constituents are included, stable water isotopes, ammonia/ammonium, radium-228, and uranium are notably absent from this analytical list. A similar requirement was instituted for produced water disposed in Class II disposal wells when CalGEM’s Underground Injection Control (UIC) regulations were updated in April 2019 (**Table 5.1**) (14 C.C.R. § 1724.7.2, 2019), although stable water isotopes and radionuclides are also absent from this list. These regulations do allow for expansions of the required suite of analyzed chemical constituents in locations where migration is suspected outside an injection zone. For instance, in August 2020, the list of required constituents was expanded by the CVRWQCB for Class II disposal wells near the Lost Hills, Belridge South, and Belridge North fields, due to concern of suspected migration outside injection zones (CVRWQCB, 2020).

Like the required analyses of produced water from stimulated wells and produced water disposed of by injection wells, chemical analyses of produced water disposed of in unlined ponds have been required since 2015, with further updates to analytical requirements in 2017 (**Table 5.1**) (CVRWQCB, 2015, 2017a, 2017b, 2017c). This analysis also includes ponds used to blend produced water with surface water and groundwater for irrigation.

Table 5.1. Chemical constituents required to be analyzed in produced waters as required by CalGEM Well Stimulation Regulations (14 C.C.R. § 1788, 2015), CalGEM UIC Regulations (14 C.C.R. § 1724.7.2, 2019), CVRWQCB Lost Hills, South Belridge, and North Belridge Section 13267 Order (CVRWQCB, 2020), and CVRWQCB Waste Discharge Requirements General Order for Oil Field Discharges to Land Order R5-2017-0034 (CVRWQCB, 2017a).

Constituent	CalGEM Well Stimulation Regulations	CalGEM UIC Regulations	CVRWQCB Lost Hills, South Belridge, and North Belridge Section 13267 Order	CVRWQCB Waste Discharge Requirements General Order for Oil Field Discharges to Land Order R5-2017-0034
General Water Quality				
Alkalinity	X	X	X	X
Electrical Conductivity		X	X[2]	X
Total Dissolved Solids	X	X	X	X
pH	X	X	X[2]	X
Temperature		X	X[2]	X
Major Ions				
Chloride	X	X	X	X
Sulfate	X	X	X	X
Bicarbonate		X	X[2]	X
Carbonate		X	X[2]	X
Hydroxide		X	X[2]	X
Calcium	X	X	X	X
Magnesium	X	X	X	X
Potassium	X	X	X	X
Sodium	X	X	X	X
Inorganics				
Boron	X	X	X	X
Bromide	X	X	X[2]	
Iodine		X	X[2]	
Iron	X	X	X	X
Lithium	X		X	X
Manganese	X	X	X	X
Nitrate	X		X	X
Nitrite	X			
Strontium	X	X	X	X
Title 22 metals[1]	X		X	X
Radionuclides/Isotopes				
Deuterium			X	X
Oxygen-18			X	X
Gross alpha	X		X	X
Gross beta	X			
Radium-226	X		X	X
Radium-228			X	X
Radon-222	X			
Uranium			X	X
Organics				
Total petroleum hydrocarbons as Crude oil		X	X	X
Benzene	X		X	X
Toluene	X		X	X
Ethylbenzene	X		X	X
Xylenes	X		X	X
Polynuclear Aromatic Hydrocarbons			X	X
Gases				
Hydrogen Sulfide	X			
Methane	X		X	

[1]Title 22 metals include: antimony, arsenic, barium, beryllium, cadmium, chromium (total & VI), cobalt, copper, fluoride, lead, mercury, molybdenum, nickel, selenium, silver, thallium, vanadium, and zinc (22 C.C.R. § 66261.24, 1994).

[2]It was unclear from the § 13267 order whether these constituents would be measured. However, given this order is an expansion of monitoring requirements, it was assumed that constituents mandated to be measured by UIC regulations would also be measured.

Efforts to improve the chemical characterization of produced water ponds appears limited to the CVRWQCB. That is, other regional water quality control boards do not require comprehensive analysis of produced water stored in lined ponds or disposed in unlined produced water ponds. There also does not appear to be any analytical requirements for testing produced water associated with spills. In the event of a large spill, important insights could be provided by comprehensive chemical analysis on the remaining produced water in a vessel.

At present, it does not appear that non-targeted and/or bioanalytical testing has been used to supplement chemical characterization of produced water. These approaches could be beneficial when produced water is used for agriculture or discharge to surface water. A significant fraction of unidentified compounds in produced water are likely degradation products of petroleum hydrocarbons. However, some unidentified compounds may be additives or transformation products of additives. Bioanalytical testing could enable assessment of toxicity, mutagenicity, teratogenicity, and other toxicological endpoints of concern. These tests are poised to be deployed for municipal wastewater recycling by the California State Water Resources Control Board (SWRCB), thus their use could be adapted for produced water (SWRCB, 2018).

In its report on well stimulation in California, the California Council on Science and Technology (CCST) recommended evaluation of “impacts of production for all OGD, rather than just the portion of production enabled by well stimulation” (Long et al., 2016). The CCST report found oil and gas production operators voluntarily reported the use of more than 300 chemical additives in California. However, knowledge of the hazards and risks associated with these chemicals was incomplete for almost two-thirds of the reported chemicals, and the toxicity and biodegradability of more than half the chemicals was uninvestigated, unmeasured, and unknown (Stringfellow et al., 2015).

Where feasible, green chemistry principles could be used to maintain an equivalent function while using less toxic chemicals and smaller amounts of toxic chemicals (Long et al., 2016). Long et al. (2016) suggested that California regulators could also disallow certain chemicals, or limit chemicals to those on an approved list, where approval depends on the chemical having an acceptable environmental profile. The latter approach reverses the usual practice, whereby an industry is permitted to use a chemical until a regulatory body proves that the chemical is harmful. Oil and gas production in the environmentally sensitive North Sea uses this pre-approval approach and might provide a model for limiting chemical risk in California (Stringfellow et al., 2015). Any of these approaches requires that operators report the unique Chemical Abstracts Service (CAS) number for all chemicals. The CCST recommended:

> “Relevant state agencies, including DOGGR [now CalGEM], should as soon as practical engage in discussion of technical issues involved in restricting chemical use with a group representing environmental and health scientists and industry practitioners, either through existing roundtable discussions or independently” (Long et al., 2016).

5.3.1. Compiled Produced Water Quality Dataset

To better understand the nature of produced water, information from available databases and reports on the chemical composition of produced water in California were compiled. Major sources of produced water quality in California include the U.S. Geological Survey (USGS) National Produced Waters Geochemical Database, the CalGEM Well Stimulation Disclosure Database, and various smaller scale USGS data releases. Detailed descriptions of produced water quality data sources are provided in **Table 5.2**.

California-specific data were extracted from the USGS National Produced Waters Geochemical Database, which includes 40 individual sources of produced water quality data from across the country, and contains measurements for major and trace elements, dissolved gases, and isotopes (both stable and radioactive). Data regarding analytical methods and detection limits are not available for the USGS National Produced Waters Geochemical Database. Water quality parameters were converted from parts per million (ppm) to milligrams per liter (mg/L) using specific gravity to allow for easier integration with other data sources.

Produced water quality data were extracted from the recovered fluids analytical table in the CalGEM Well Stimulation Disclosure Database. The CalGEM database maintains data regarding the chemical analysis of recovered fluids (after three well volumes and 30 days of operation following stimulation) and is publicly available for download (CalGEM, 2021a). Although recovered fluids from well stimulation may ultimately differ from well stimulation produced water, they are handled in the same manner in California, aligning with the methodology of previous studies (e.g., Shonkoff et al., 2021), and thus were included in the analysis of produced water quality. Data for volatile organic compounds (VOCs) and other organic compounds are limited to the CalGEM database, which includes produced water from matrix acidizing, acid fracturing, and hydraulic fracturing activities. On a statewide basis, chemical additives used in upstream OGD and degradation byproducts are generally not monitored in produced water, with notable exceptions for guar gum and silica in the CalGEM database. However, CVRWQCB General Orders and waste discharge requirements (WDRs) for produced water reuse projects require that the operator list the chemicals and additives used, and then test for those ones that have approved analytical methods. Data for organic compounds in produced water from conventional OGD is generally unavailable.

Other data sources that were incorporated include individual USGS data releases containing both historical and current produced water quality data from various oil fields throughout California. Due to their inclusion of historical produced water quality data, these data releases varied in data quality, background information regarding analytical methods, detection limits, geographic coverage, and the types of water quality parameters measured. Three USGS data releases (Everett et al., 2019; Gillespie et al., 2019; Metzger et al., 2018) contained only total dissolved solids (TDS) data and were excluded from our compiled dataset. Other sources of produced water quality, such as monitoring data from produced water ponds, were excluded from the compiled dataset to focus on produced water quality prior to any treatment, blending, evapoconcentration, or volatilization that could impact produced water quality in ponds. Chemical characterization of produced water ponds is discussed in Section 5.5.3.

Due to the individual nature of each database, our compiled produced water quality dataset has a number of limitations, including:

- USGS datasets could not be independently verified and did not always specify protocols, methods, or detection limits, limiting interpretation and integration.

- For all datasets, results that were reported as zero, a non-detection qualifier (e.g., “ND”), below a detection/reporting limit (e.g., <0.05), or negative were not considered in compiled summary statistics. Results reported as a range (e.g., >100 mg/L) were removed to allow for consolidation. If no measurement value was provided for a given analysis or if the value was “NA,” it was assumed that the analysis was not performed. Charge balance values were included in some databases; however, data points were not removed because large charge imbalances were often due to missing major ion analytes.

- Information on the source of produced water (e.g., water body, well identifiers, latitude, and longitude) beyond the oil field was not always available. Geospatial information is necessary to identify human health risks associated with produced water handling and reuse.

5.3.2. Compiled Produced Water Quality Dataset Summary

A total of 4,242 unique produced water samples were analyzed for subsets of 287 different water quality parameters and chemical compounds. Water quality parameters included standard water quality indicators, naturally occurring radioactive materials (NORM) and other radioactivity indicators, major and minor ions, trace elements, dissolved gasses, organic compounds, select compounds relating to hydraulic fracturing additives, and isotopes. Summary statistics were calculated for select parameters (**Table 5.3**), and additional water quality parameters (Table E.1, Appendix E.1) contained within the compiled produced water quality dataset.

Standard water quality parameters (e.g., alkalinity, pH) and ions (e.g., calcium, magnesium, sodium, chloride, alkalinity, and TDS) were the most often reported constituents. TDS concentrations in the vast majority (95%) of samples in the dataset are 3,250 mg/L or more (**Table 5.3**), well above the upper limit of 2,000 mg/L TDS used as a general rule of thumb for acceptable irrigation water (Ayers & Westcot, 1985), although some crops can handle higher TDS irrigation water. Consequently, most produced waters included in this database would require treatment or dilution before reuse for agricultural purposes (which would also dilute potential constituents of concern).

The CalGEM Well Stimulation Disclosure Database is the only synthesized database that contains monitoring data for organic compounds often co-produced with oil and gas. Benzene, toluene, ethylbenzene, and xylenes (BTEX) compounds were detected in most samples in the CalGEM database, with median concentrations of 0.71, 1.9, 0.25, and 1.2 mg/L, respectively. These levels are orders of magnitude higher than those reported in produced water ponds that supply produced water for irrigation and for discharge to land (Mahoney et al., 2021). BTEX compounds are expected to volatilize from produced water and pose additional hazards to human health if emissions are uncontrolled. For example, benzene is a known human carcinogen, with a California Maximum Contaminant Level of 1 µg/L. Additional discussion on emissions from produced water ponds is provided in Section 5.5. Other notable organic compounds detected to a lesser extent include 2,2-dibromo-3-nitrilopropionamide (DBNPA, CASRN: 10222-01-2), and naphthalene. In instances where a large fraction of analyses for compounds resulted in non-detection, there may be an upper bias estimation in quartile and median concentrations.

Table 5.2. Overview of California produced water quality datasets.

Organization	Source	Data period	Region	Number of parameters	Number of samples	Description
USGS	USGS National Produced Waters Chemical Database (Blondes et al., 2018)	Feb 1937–Nov 1996	Los Angeles, Sacramento, San Joaquin, Santa Barbara-Ventura, Santa Maria basins	45	856	Produced water quality data including major and minor ions, trace elements, isotopes, dissolved gases, and naturally occurring radioactive materials.
CalGEM	Well Stimulation Disclosure Database (CalGEM, 2021a)	Jul 2015–Jun 2021	California	167	2,346	Composition of recovered fluids within 30 days following the end of well stimulation treatment. Data includes major and major ions, trace elements, isotopes, radioactive isotopes, and various VOCs.
USGS	Davis et al. (2016)	Nov 2014	North Belridge, South Belridge, Lost Hills oil fields	38	4	Produced water from four petroleum wells analyzed for dissolved hydrocarbon gases and their isotopic composition, salinity, major ions, nutrients, dissolved organic carbon, and stable isotopes of water and strontium dissolved in water.
USGS	Gannon et al. (2018)	Jul 2016–Oct 2017	Fruitvale, Lost Hills, North Belridge, and South Belridge oil fields	75	23	Produced water data including dissolved noble and hydrocarbon gases and their isotopic composition, salinity, major ions, nutrients, dissolved organic constituents and carbon, and stable isotopes of water and solutes dissolved in water.
USGS	Gans et al. (2018)	Jan 1933–Dec 2013	Fruitvale oil field	40	203	Historical produced water quality data including major ions, some minor ions, TDS, pH, specific gravity, resistivity, electrical conductivity, and charge balance.
USGS	Gans et al. (2019)	Nov 1930–May 1999	Lost Hills, North Belridge, and South Belridge oil fields	31	260	Historical produced water quality data including major ions, some minor ions, TDS, pH, specific gravity, resistivity, electrical conductivity, and charge balance.
USGS	Metzger et al. (2020)	Dec 1933–Nov 2016	Los Angeles and Orange County	59	200	Historical produced water quality data including major ions, some minor ions, TDS, pH, specific gravity, resistivity, electrical conductivity, and charge balance.
USGS	Metzger & Herrera (2020)	Nov 1958–Jan 2014	Orcutt and Oxnard oil fields	58	58	Historical produced water quality data including major ions, some minor ions, TDS, pH, specific gravity, resistivity, electrical conductivity, and charge balance.
USGS	Metzger (2021)	Jan 1948–Mar 2016	San Ardo	73	271	Historical produced water quality data including major ions, some minor ions, TDS, pH, specific gravity, resistivity, electrical conductivity, and charge balance.
USGS	Gans et al. (2021)	Jan 1957–Jan 1990	North Coles Levee oil field	45	40	Historical produced water quality data including major ions, some minor ions, TDS, pH, specific gravity, resistivity, electrical conductivity, and charge balance.

The CalGEM database was also the main source of data for radioactive indicators and NORM. Median values for gross alpha, gross beta, and radium-226 + radium-228 in produced water are 66, 144, and 38 picocuries per liter (pCi/L), respectively, well above screening levels of 15, 50, and 5 pCi/L, respectively (**Table 5.3**).

Overall, currently available produced water quality data sources are not adequate to evaluate produced water composition on a statewide level with respect to potential impacts to human health. The CalGEM "Well Stimulation Disclosure Database" is the most comprehensive but is limited in scope to stimulated wells. Stimulated wells represent a small fraction of the total number of producing oil and gas wells in California. Formation of a comprehensive produced water dataset would better inform assessment of exposure pathways associated with disposition of produced water.

5.3.3. Chemical Additives and Transformation Products in Produced Water

Chemical additives used in oil and gas production operations have the potential to undergo subsurface chemical transformations and return to the surface via flowback and produced water. Although degradation pathways and products have been established for some chemical additives under standard state conditions (i.e., standard temperature and pressure), downhole conditions including high temperatures and pressures can result in altered biodegradation potentials and unexpected chemical reactions and degradation productions (Kahrilas et al., 2015). The formation of degradation byproducts from downhole chemical transformations are poorly understood, yet can have significant implications for produced water quality, treatment, and disposal, and for human health due to environmental releases (Abdullah et al., 2017).

Current studies of degradation byproducts from transformations of chemicals used in OGD are limited to hydraulic fracturing, of which most are focused on regions outside of California (Hoelzer et al., 2016; Xiong et al., 2018, 2020). The characterization of flowback and produced water in these studies have detected compounds that cannot be attributed to geologic sources or chemical additive sources (Hoelzer et al., 2016; Maguire-Boyle & Barron, 2014; Sumner & Plata, 2018). Although these studies are not specific to California, some of the hydraulic fracturing chemical additives investigated in these studies are also used in California. Additionally, there is significant overlap in chemical usage between different upstream OGD operations as discussed in Chapter 2, Appendix B.

Table 5.3. Select constituents from the compiled produced water quality database for OGD in California.

					Percentile			
Constituents (units)	**Detections (%)**	**Min**	**Med**	**Max**	**5th**	**25th**	**75th**	**95th**
General Water Quality								
Alkalinity as $CaCO_3$ (mg/L)	1,490 (100)	0.34	2,800	5,800	250	2,000	3,300	4,100
Hardness (mg/L)	307 (99.4)	0.2	150	8,820	2.1	5.8	506	2,970
Specific Conductance (mS/cm)	356 (100)	29	35,000	190,476	3,790	16,150	42,000	60,210
Total Dissolved Solids (mg/L)	4,070 (100)	28	26,000	890,000	3,250	18,000	31,000	47,000
Total Organic Carbon (mg/L)	22 (95.7)	18	225	2,054	25.7	110	798	1,167
pH (pH units)	3,967 (100)	1.0	7.6	11.8	6.7	7.3	7.8	8.3
Major Ions								
Bicarbonate (mg/L)	1,702 (99.2)	2.0	1,154	12,809	163	582	2,270	4,550
Carbonate (mg/L)	329 (27.5)	1	51.6	2,250	3.76	20.4	138	447
Bromide (mg/L)	2,606 (97.6)	0.19	100	16,000	28	73	130	166
Chloride (mg/L)	4,211 (99.9)	1.0	14,000	360,000	408	8,670	17,000	24,980
Sulfate (mg/L)	3,023 (73.8)	0.1	38	15,250	3.77	24	87.2	475
Calcium (mg/L)	4,333 (99.9)	0.1	190	190,000	22	128	350	2,110
Magnesium (mg/L)	4,306 (99.5)	0.08	120	10,000	6.8	67	166	457
Potassium (mg/L)	3,082 (99.8)	1.2	190	52,000	33	140	300	1,400
Sodium (mg/L)	4,102 (100)	4.48	8,700	120,000	870	6,200	10,400	13,000
Inorganics								
Boron (mg/L)	3,289 (99.3)	0.02	92	158,000	4.2	62	105	150
Antimony (µg/L)	253 (9.8)	10	160	17,000	30	70	260	478
Arsenic (µg/L)	194 (7.6)	10	190	4,600	40	90	298	996
Barium (mg/L)	3,316 (96.6)	0.01	7.7	26,300	1.0	5.1	11	55
Beryllium (µg/L)	76 (2.9)	10	10	4,130	10	10	20	170
Cadmium (µg/L)	52 (2.0)	10	30	420	10	10	40	143
Chromium (µg/L)	643 (25.1)	10	40	9,400	10	30	70	200
Chromium VI (µg/L)	68 (3.1)	10	10	610	10	10	20	93
Cobalt (µg/L)	102 (3.9)	10	30	8,510	10	10	50	344
Copper (µg/L)	884 (33.6)	10	40	184,000	10	30	80	619
Iron (mg/L)	2,693 (91.8)	0.01	12	48,100	0.4	3.5	37	130
Lead (µg/L)	240 (9.3)	10	80	30,000	10	20	170	1,200
Lithium (mg/L)	2,759 (98.9)	0.004	5.8	17,500	0.99	4.15	8.3	18.1
Manganese (µg/L)	2,579 (95.0)	10	480	85,7000	110	250	920	2,800
Mercury (µg/L)	7 (0.3)	10	30	980	10	10	160	755
Molybdenum (µg/L)	343 (13.2)	10	40	48,500	10	20	70	270
Nickel (µg/L)	550 (21.5)	10	50	22,000	10	22.5	100	396

					Percentile			
Constituents (units)	**Detections (%)**	**Min**	**Med**	**Max**	**5th**	**25th**	**75th**	**95th**
Selenium (µg/L)	429 (16.7)	10	280	15,000	54	130	530	1,900
Silver (µg/L)	33 (1.3)	10	50	260	10	30	60	162
Strontium (mg/L)	2,886 (99.8)	0.01	11.2	190,000	2.80	7.2	16	126
Thallium (µg/L)	27 (1.0)	10	90	6,400	13	25	365	3,010
Vanadium (µg/L)	91 (3.6)	10	70	24,000	10	45	135	1,350
Zinc (µg/L)	1,017 (38.8)	10	110	243,000	30	70	250	1,920
Silica (mg/L)	744 (98.5)	0.18	60	2,200	14	36	90.2	177
Radionuclides/Isotopes								
Gross alpha (pCi/L)	1,916 (81.8)	0.05	66.1	2,589	7.33	32.9	109	238
Gross beta (pCi/L)	2,283 (97.6)	0.14	144	41,000	29.2	88.2	227	1,379
Radium 226 (pCi/L)	2,326 (98.6)	0.03	24.7	917	5.21	15.7	33.2	65.5
Radium 228 (pCi/L)	258 (94.8)	0.08	13	515	1.48	5.59	28.6	60.8
Radon 222 (pCi/L)	1,148 (71.5)	0.52	106.3	250,690	10.2	49	213	1,557
Uranium (µg/L)	8 (22.2)	0.28	1.84	7.03	0.44	1.25	4.37	6.84
Nutrients								
Ammonia (mg/L)	158 (99.3)	1.28	27.5	2,300	7.08	17	41.0	75.5
Ammonium (mg/L)	272 (92.8)	3	139	2,560	12.2	73.8	201	377
Nitrate (mg/L)	214 (8.90)	0.1	12	800	0.6	1.59	24.8	170
Nitrite (mg/L)	646 (28.0)	0.04	0.09	10	0.04	0.05	0.27	0.97
Organics								
Total carbohydrates (mg/L)	2,041 (97.4)	1.2	97	11,000	21	53	190	560
Benzene (µg/L)	2,293 (98.0)	10	710	25,000	80	300	1,400	3,600
Toluene (µg/L)	2,307 (98.5)	10	1,900	61,000	170	885	3,000	4,970
Ethylbenzene (µg/L)	2,277 (97.2)	10	250	5,300	40	140	360	670
m-Xylenes (µg/L)	68 (100)	210	770	6,000	300	488	1,200	2,030
o-Xylene (µg/L)	2,129 (98.3)	10	420	5,700	70	230	640	1,200
Total Xylenes (µg/L)	2,307 (98.5)	10	1,200	19,000	140	570	2,000	3,800
Naphthalene (µg/L)	9 (75)	10	30	3,900	14	30	250	2,980
2,2-Dibromo-3-nitrilopropionamide (mg/L)	52 (32.7)	5	15	20	5	10	20	20

Abbreviations: mg/L - milligrams per liter; mS/cm - milliSiemens per centimeter; pCi/L - picocuries per liter; ug/L - micrograms per liter

5.3.3.1 Organohalide Compounds

Halogenated organic compounds are an area of growing concern. They have been detected in multiple studies of hydraulic fracturing flowback and produced waters where they were not reported in chemical disclosures (Evans et al., 2019; Hoelzer et al., 2016; Sumner & Plata, 2018). Halogenated benzenes, pyrans, alkanes, methanes, and acetones have been detected in hydraulic fracturing wastewaters from the Fayetteville Shale (Hoelzer et al., 2016) and chlorocarbons and organobromides have been detected in produced water from the Barnett, Marcellus, and Eagle Ford formations (Maguire-Boyle & Barron, 2014). Evans et al. (2019) detected 20 organohalide compounds in Marcellus Shale produced water (e.g., haloalkanes, haloamides, haloamines, halobenzenes, and haloesters), and determined microbial organohalide transformation may play a direct role in the formation of these organohalides.

A study conducted by Sumner and Plata (2018) found that epichlorohydrin, cinnamaldehyde (CASRN: 104-55-2), and 2,2-dibromo-3-nitrilopropionamide (DBNPA) showed evidence of halogenation when subjected to simulated downhole hydraulic fracturing conditions. They concluded that halogenation reactions are facilitated by the following conditions:

1) Presence of oxidants (i.e., breakers) that can react with halides to form reactive intermediates, which then react with organic species.
2) High concentrations of chloride, bromide, or iodide in formation waters increase the likelihood of halogenated product formation. Other factors, including pH and temperature, can also affect halogenated species formation rates and distribution.
3) Reaction kinetics are highly dependent on well temperature, increasing by an order of magnitude with a 40°C (~104°F) increase.

DBNPA is widely used in hydraulic fracturing operations in California. Cinnamaldehyde has been reported in a limited number of hydraulic fracturing and maintenance acidizing operations, and in operations in the southern San Joaquin Valley that provide produced water for irrigation. Epichlorohydrin has not been reported in any upstream oil and gas operations in California.

Halogenated transformation products may also form through the downhole reaction of guar gum-based fracturing fluids using borate or zirconium crosslinkers with oxidative breakers (Sumner & Plata, 2019). Under simulated conditions, Sumner and Plata (2019) found oxidative breakers — such as persulfates, chlorites, and hypochlorites — can react with other additives (e.g., cinnamaldehyde, citric acid) to form various halogenated transformation products. Hydraulic fracturing operations in California predominantly use guar-based fracturing fluids and all the major reactants in this study (i.e., borate and zirconium crosslinkers, citric acid, persulfates, chlorites, hypochlorites, and cinnamaldehyde) have been reported in well stimulation operations in California.

5.3.3.2 Polyacrylamide

The chemical and mechanical degradation of polyacrylamide in high-volume hydraulic fracturing was investigated by Xiong et al. (2018, 2020). They found significant degradation in polyacrylamide due to both mechanical shearing and free radical chain scission mechanisms, resulting in a wide distribution in polyacrylamide molecular weights. The abundance of degraded polyacrylamide may complicate produced water treatment and increase the likelihood of environmental releases of acrylamide, a toxicant and probable human carcinogen (IARC, 1994). Polyacrylamide is a common friction reducer used in hydraulic fracturing fluids in shale plays across the United States (Stringfellow et al., 2014). Although polyacrylamide has not been reported in hydraulic fracturing operations in California, primarily due to the predominant use of gel-based fracturing fluids in the state, polyacrylamide has been used as a viscosity modifier in a limited number of horizontal and vertical well drilling operations reported to the South Coast Air Quality Management District (SCAQMD) and the CVRWQCB (Stringfellow et al., 2015, 2017). It is unclear if the described degradation mechanisms also apply to polyacrylamide use in conventional well drilling operations.

Table 5.4. Summary of studies investigating chemical transformations of specific chemical additives related to hydraulic fracturing.

Study	Precursor chemicals	Halides	Halogenated categories	Detected products	Conditions
Kahrilas et al. (2016)	Glutaraldehyde	Bromide Chloride Iodide	-	Glutaraldehyde dimers trimers; possibly unchanged depending on conditions	Influenced by pH, temperature, and salinity. May readily degrade under hot, alkaline conditions. Likely to return to surface with transformation products in cooler, acidic, saline conditions.
Sumner and Plata (2018)	Epichlorohydrin Cinnamaldehyde DBNPA	Bromide Chloride Iodine	Methanes Acetonitriles Alcohols Others	Chloroacetonitrile dichloroacetonitrile bromoacetonitrile dibromoacetonitrile tribromomethane chloroiodomethane boromodichloromethane dibromochloromethane iodoacetonitrile α-iodocinnamaldehyde α-chlorocinnamaldehyde α-bromocinnamaldehyde 2,3-dichloro-1-propanol 1,3-dichloro-2-propanol 3-chloro-1,2-propanediol	Presence of oxidants (i.e., breakers) that can react with halides to form reactive intermediates, which then react with organic species. pH and temperature affect halogenated species formation rates and distribution.
Sumner and Plata (2019)	Guar gum Borate and zirconium crosslinkers Oxidant breakers Citric acid	Bromide Chloride Iodine	Methanes	Bromochloromethane Chloroiodomethane Bromodichloromethane Dibromochloromethane Chlorodiiodomethane Bromodiiodomethane Tribromomethane Trichloromethane Triiodomethane	Halogenation requires high concentrations of oxidants. Citric acid more prone to trihalomethane formation than guar gum. Zirconium crosslinkers more prone to trihalomethane formation than borate-based crosslinkers.
Xiong et al. (2018, 2020)	Polyacrylamide	-	-	Degraded short chain polyacrylamides Possibility of acrylamide monomer formation	Degradation caused by both physical shearing and chemical decomposition.

5.3.3.3 Glutaraldehyde

A study of glutaraldehyde under simulated hydraulic fracturing conditions found that degradation of glutaraldehyde is influenced by pH, temperature, and salinity (Kahrilas et al., 2016). Under downhole conditions, glutaraldehyde is suspected of undergoing autopolymerization, reactions with thiols and sulfides, or reactions with NH_3 or amines. These transformation products could precipitate out of solution at high temperatures or under alkaline conditions but would likely return to the surface with unreacted glutaraldehyde products in cooler, more acidic, and saline conditions. Glutaraldehyde is a commonly used biocide in upstream OGD in California and has been reported in all of the chemical disclosure datasets (Shonkoff et al., 2021; Stringfellow et al., 2017). Glutaraldehyde is a skin, eye, and nose irritant that has a U.S. Environmental Protection Agency (US EPA) risk based screening level for chronic ingestion exposure of 2 mg/L based on the Agency for Toxic Substances and Disease Registry (ATSDR) minimum risk level of 0.1 mg/kg/day (ATSDR, 2017), and an California Office of Environmental Health Hazard Assessment (OEHHA) chronic inhalation reference exposure level of 0.02 ppb (OEHHA, 2020). The toxicity of the investigated glutaraldehyde transformation products are largely unknown (Kahrilas et al., 2016) and it is important to note that the absence of toxicological information does not mean the absence of health risk.

5.3.3.4 Per- and Polyfluoroalkyl Substances (PFAS)

Recent reports have linked the use of per- and polyfluoroalkyl substances (PFAS) — sometimes referred to as “forever chemicals” — with hydraulic fracturing fluids in the U.S. (Horwitt & Gottlieb, 2021, 2022). Based on the list of PFAS maintained in the U.S. EPA CompTox Chemicals Dashboard (US EPA, 2022a; 2022b), the only PFAS chemical reported in hydraulic fracturing chemical disclosures in California is polytetrafluoroethylene (PTFE) (Stringfellow et al., 2015; Shonkoff et al., 2021). PTFE — commonly known as Teflon — is not included in chemical analyses of produced water and subsequently has not been documented in any produced water samples from California.

The risk posed by the inclusion of PTFE in hydraulic fracturing fluids is unknown. It has been argued that PTFE should be considered a polymer of low concern and distinctly different from other PFAS for hazard assessment due to its thermal, chemical, and biological stability and toxicological studies (Henry et al., 2018); however, others suggest that the complete life cycle of fluoropolymers (including PTFE) should be taken into account (Lohmann et al., 2020). While PTFE is known to produce fluorinated degradation products when heated to temperatures greater than 250 °C (482 °F) (Lohmann et al., 2020), no studies of PTFE degradation under hydraulic fracturing conditions appear to have been conducted, and thus transformation products generated by PTFE in downhole conditions are relatively unknown. However, given that guar-based fracturing fluids — the dominant type used in California — are generally unstable above 149 °C (300 °F) but may be used under conditions as high as 204 °C (400 °F) with appropriate stabilizers (Almubarak et al., 2021), it is possible that proper conditions for the generation of fluorinated degradation products are not reached.

5.3.3.5 Modeling

There remains a need to better characterize the potential transformation products and conditions that contribute to their formation (Kahrilas et al., 2016). There are no studies that look specifically at transformation products from hydraulic fracturing (or conventional OGD) in California to our knowledge; however, the chemical transformations documented elsewhere are possible if similar downhole conditions and fluid chemistry are present in California.

Limited studies of widely used hydraulic fracturing chemical additives have shown there is a potential for multiple types of halogenated organic compounds to form and return to the surface with flowback and produced water. Other studies have detected similar compounds in produced water that do not match disclosed chemical additives or geogenic compounds. These halogenated organic compounds are generally environmentally persistent with varying degrees of human toxicity and are regulated in drinking water as disinfection byproducts.

Standard water quality monitoring methods and approaches overlook a variety of potential constituents found in produced water, including chemical additives and their transformation products. Non-targeted analytical methods to monitor produced water quality, such as high-resolution mass spectrometry with liquid chromatography, are an emerging approach that could detect the presence of unknown or problematic transformation products, such as halogenated organic compounds (Shonkoff et al., 2021).

In an effort to facilitate future studies of subsurface chemical transformations and develop predictive modeling tools, Sumner and Plata (2020) developed a geospatial database that combines FracFocus chemical disclosure information, subsurface conditions, and produced water compositions to identify regions where chemical transformation conditions are likely to occur. Predictive tools such as these can inform future produced water monitoring programs, and help operators make informed decisions on the usage of chemical additives in order to mitigate potential problematic chemical transformations (Sumner & Plata, 2020).

5.4. Contamination Pathways and Regulations for Underground Injection Control Wells

The U.S. EPA recognizes six pathways through which injected fluids could potentially migrate into underground sources of drinking water (USDW), causing groundwater contamination and impact to domestic or municipal water wells:

1) migration of fluids through a faulty injection well casing;
2) migration of fluids through the annulus located between the casing and wellbore;
3) migration of fluids from an injection zone through the confining strata;
4) vertical migration of fluids through improperly abandoned and improperly completed wells that penetrate the injection zone;
5) lateral migration of fluids from within an injection zone into a protected portion of that stratum;
6) direct injection of fluids into or above an USDW (Osbourne, 2002).

If injection wells are located near a surface water body, contaminants may enter surface water and downstream drinking water intakes through migration at the borehole or through preferential flow paths in subsurface media (**Figure 5.4**). If idle production wells are located near surface water, over pressurization could cause a production well to flow at the surface, with subsequent entry into surface water.

According to the U.S. EPA's Underground Injection Control (UIC) well inventory, as of 2019, there were 1,698 produced water disposal wells (Class IID) and 34,990 enhanced recovery (Class IIR) wells in California (US EPA, 2018). California is second only to Texas in the number of UIC Class II wells in the state.

The California Class II UIC program is managed by CalGEM under California Public Resources Code § 3106, which provides the State Oil and Gas Supervisor broad authority to protect public health and safety. The existing regulations include specific data requirements that an applicant must satisfy before CalGEM can approve an injection project. Project data requirements include engineering studies (including area of review determination and casing diagrams); geologic studies (including structural contour and isopach maps and reservoir characteristics); and injection plans (including identification of the proposed maximum anticipated surface injection pressure and proposed monitoring system or methods to ensure no damage is occurring).

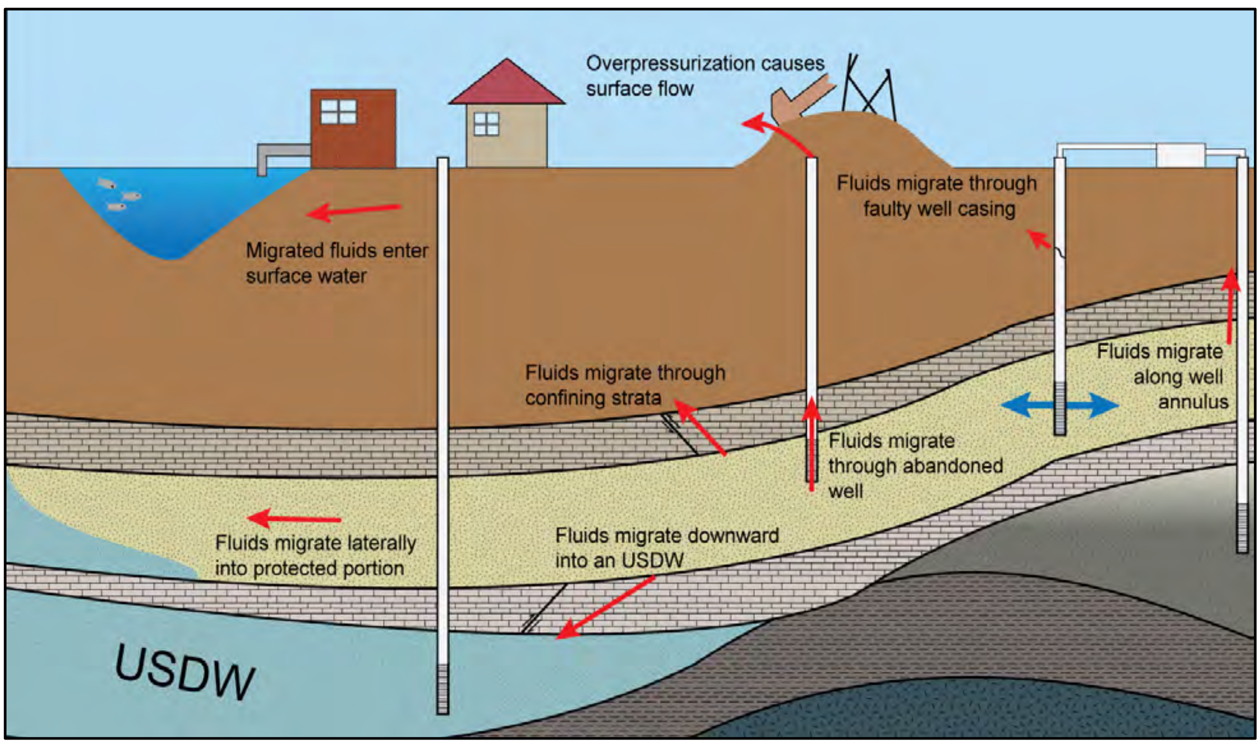

Figure 5.4. Conceptual contamination and exposure pathways of underground injection control wells.

In 2011, the U.S. EPA hired an independent consultant group to conduct an audit of California's UIC Program (Walker, 2011). The consultant group found inconsistencies in the definition of protected water. CalGEM reported protecting "freshwater" containing less than or equal to 3,000 mg/L TDS, while federal regulations (the Safe Drinking Water Act) require protection of an USDW at less than or equal to 10,000 mg/L TDS. The audit also found the Division lacking in the implementation of a number of requirements, including consistent area of review analyses, accurate determination of fracture gradients for injection projects, and enforcement of appropriate maximum allowable surface injection pressures (Walker, 2011). Also in 2011, an oil industry employee died when the ground beneath them gave way and they fell into a pool of heated fluid. The pool, known as a "surface expression," was in part the result of nearby cyclic steam injection operations. The existence of a surface expression is indicative of injection being performed at rates and pressures above safe levels and that injection is not confined to the approved injection zone (CalGEM, 2019). In 2019, UIC regulations were revised to prohibit surface expressions and enact monitoring and prevention requirements (14 C.C.R. § 1724.11).

In 2014, CalGEM ordered the immediate closure of 11 disposal wells in Kern County that potentially presented health or environmental risks. The SWRCB identified 108 water supply wells located within a one-mile radius of these wells. However, sampling of the wells did not indicate impact (Bishop, 2014).

Following the discovery of permitting injection of produced water into nonexempt aquifers, the California Legislature enacted Senate Bill 83 (SB 83) in 2015 (California Senate Bill No. 83, 2015) in part to mandate review of proposed aquifer exemptions by the State and regional water quality control boards. The SWRCB and nine regional water quality control boards (RWQCB) now play a role in both project review and approval in ensuring that injection will not adversely degrade USDWs, which could lead to an exposure pathway for current and future groundwater users. CalGEM and the SWRCB now coordinate approval of aquifer exemptions (CalGEM, 2019).

Pursuant to SB 83 (2015), the California Natural Resources Agency and the California Environmental Protection Agency appointed a panel comprised of a diverse group of individuals with expertise and scientific backgrounds in geology, toxicology, oil and gas industry, public health, and the environment, as well as representatives from the agricultural and environmental justice communities. The purpose of the panel is to evaluate the regulatory performance and administration of the UIC Program and make recommendations on how to improve its effectiveness by evaluating resource needs, statutory or regulatory changes, and program organization (CalGEM, 2021b). The first public meeting was held on May 29, 2018 (Cal-Span, 2018). Results from the panel are forthcoming at the time of writing this report. A performance audit conducted by California Department of Finance and completed in 2020 evaluated CalGEM's UIC project approval process and highlighted the need to (1) improve UIC program controls, (2) strengthen project review documentation and transparency, (3) ensure project modifications or expansions are not approved through infill well reviews, (4) discontinue use of placeholder projects and issuance of associated well permits, (5) improve well permit detail and review documentation, and (6) strengthen Axial Dimensional Stimulation Area (ADSA) review documentation (California Department of Finance, 2020).

It is not clear exactly how many Californians relying on water wells for domestic use could be potentially impacted by underground disposal wells. As a result of a proximity analysis conducted as part of Chapter 7 of this report, about 261,000 Californians were found to live within 1 km (3,281 ft) of a water disposal well (**Figure 5.5**). However, distances of these wells to domestic water wells were not considered due to the limited spatial resolution of these data. A detailed discussion of this issue is included in Section 5.5.7. Locations of all wells with a type of “Water Disposal” in the CalGEM “All Wells” dataset are provided in Figure E.1, Appendix E.2.

5.5. Contamination Pathways and Regulations for Produced Water Ponds

5.5.1. Background

The SWRCB defines a produced water pond as an earthen structure that is used to store, dispose, treat, and/or separate liquids; and of which produced water comprises a significant amount of liquid (SWRCB, 2019). Produced water ponds can be lined, typically with a type of sprayed concrete called gunite, or more commonly, unlined. The SWRCB classifies produced water ponds as one of three statuses: (1) active —ponds that currently receive produced water; (2) inactive—ponds that have a physical connection to a produced water source but currently do not receive produced water; or (3) historical/closed —ponds that have no physical connection to a produced water source and have been out of service for an extended period of time (SWRCB, 2019).

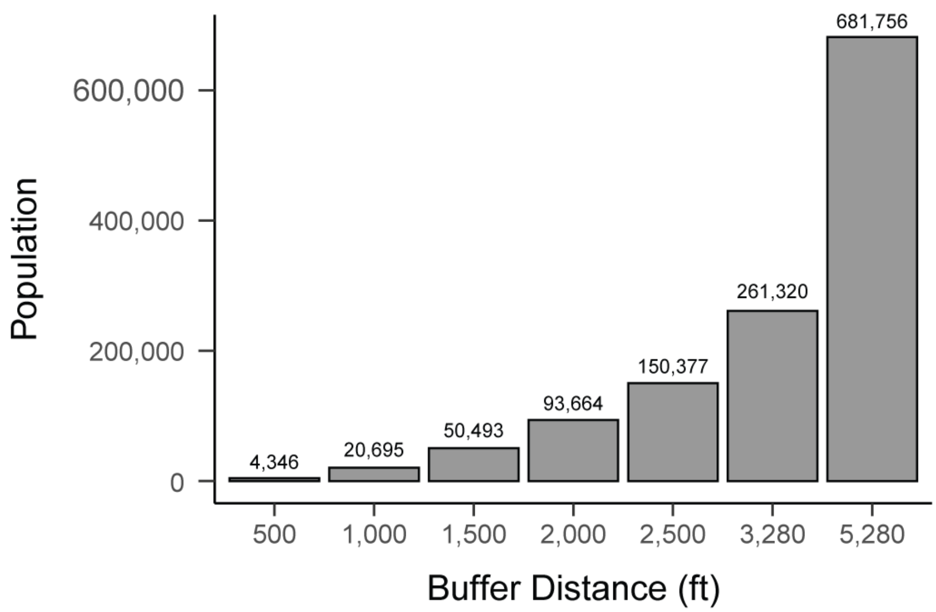

Figure 5.5. Total populations living within buffer distances of water disposal wells.

Historically, the primary method of surface-based (non-injection) produced water disposal in California has been discharge to unlined produced water ponds (**Figure 5.6**), which has been ongoing in California since the early 1900s. For instance, Bean & Logan (1983) state that 570,000 acre-feet of produced water, containing 15 million tons of salt, was disposed of in sumps or shallow injection wells from 1900 to 1980 in southwestern Kern County alone.

Recently, DiGiulio & Shonkoff (2021) conducted an examination of produced water disposal trends in the SB1281 dataset. They found the volume of produced water disposed in unlined ponds peaked in 2007 at 609 million barrels (MMbbls) (23.0% of produced water disposition), and the proportion of produced water disposed in unlined produced water ponds peaked in 2003 (24.5% produced water disposition). Disposal of produced water to unlined produced water ponds decreased significantly after 2014, with a low of 45.1 MMbbls in 2017 (corresponding to 1.4% of total produced water disposition). Discharge to lined produced water ponds (evaporation ponds) tapered off after 1998 after reaching a peak in 1992 (8.2% of produced water) and a low in 2001 (0.01% of produced water).

Prior to discharge to unlined ponds, treatment of produced water typically consists of gravity separation of oil and water using wash or storage tanks. Emulsion breakers, surfactants, clarifiers, and other additives may be used in wash tanks to facilitate oil/water separation (WZI Inc., 2020). At small facilities consisting of one to three unlined ponds, produced water is subsequently discharged to unlined ponds where remaining oil is skimmed during evaporation and percolation. At larger facilities, produced water enters a series of unlined ponds for skimming of oil prior to discharge to larger unlined ponds for evaporation and percolation (Jordan et al., 2015).

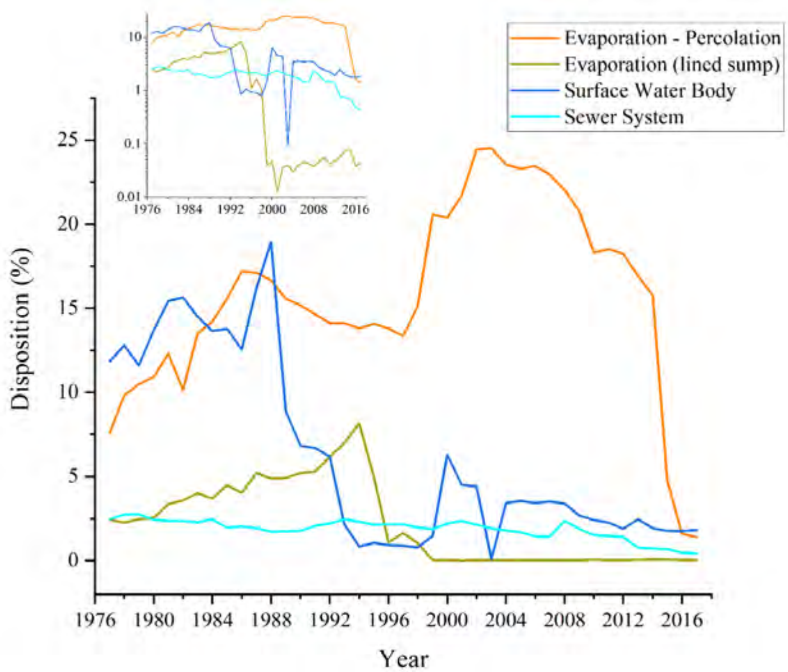

Figure 5.6. Percent produced water disposal to the surface (evaporation-percolation ponds, lined produced water ponds, sewage, and surface water) from 1977 to 2017 as reported to CalGEM. Inset provided in logarithmic scale to better illustrate disposition of lined sumps after 1998. Source: Figure S2 from DiGiulio et al. (2021).

One area of growing concern in California is the impact to groundwater used for public water supply from ongoing and past disposal of wastewater from OGD (i.e., produced water) into unlined produced water ponds (Grinberg, 2014, 2016; Heberger & Donnelly, 2015; Jordan et al., 2015; Stringfellow et al., 2015). The primary intent of percolation pits is to percolate produced water into subsurface media. This practice provides a direct pathway to transport produced water constituents into groundwater (Jordan et al., 2015; Stringfellow et al., 2015). Contaminated groundwater could then impact municipal, domestic, and irrigation wells (**Figure 5.7**). In addition, contaminated groundwater could also intercept rivers, streams, and surface water resources. Finally, contaminated water used by plants (including food crops), fish, and wildlife can introduce contaminants into the food chain. Other pathways of human exposure include skin contact via accidental exposure (e.g., falling into a pond) and inhalation of volatile compounds present in produced water from ponds.

Approximately 89% of produced water ponds and 99% of unlined produced water ponds in California are in the Tulare Basin, in the San Joaquin Valley (SJV) (DiGiulio & Shonkoff, 2019, 2021). Facilities containing unlined produced water ponds vary from single ponds to large complexes consisting of numerous ponds. Between 1977 and 2017, 16,129 MMbbls of produced water were disposed in unlined produced water ponds (**Figure 5.8**) representing a potential wide-scale legacy groundwater contamination issue in the Tulare Basin, where most unlined ponds are located (DiGiulio et al., 2021; DiGiulio & Shonkoff, 2019).

The SJV is arid-to-semiarid hot, with total annual precipitation from 12 to 45 cm (5 to 18 in) falling mostly in winter months (Faunt et al., 2010). While evaporation exceeds precipitation throughout most of the year, in practice, the year-round flow of water to unlined ponds results in most water percolating to subsurface media (Jordan et al., 2015). For instance, an analysis of evaporation/percolation in three unlined ponds in the Edison Field in the southeastern portion of the Tulare Basin indicated that 92% of disposed water percolated to subsurface media in 2006 (WZI Inc., 2020). Consequently, this disposal practice may introduce a potential contamination pathway for nearby USDWs.

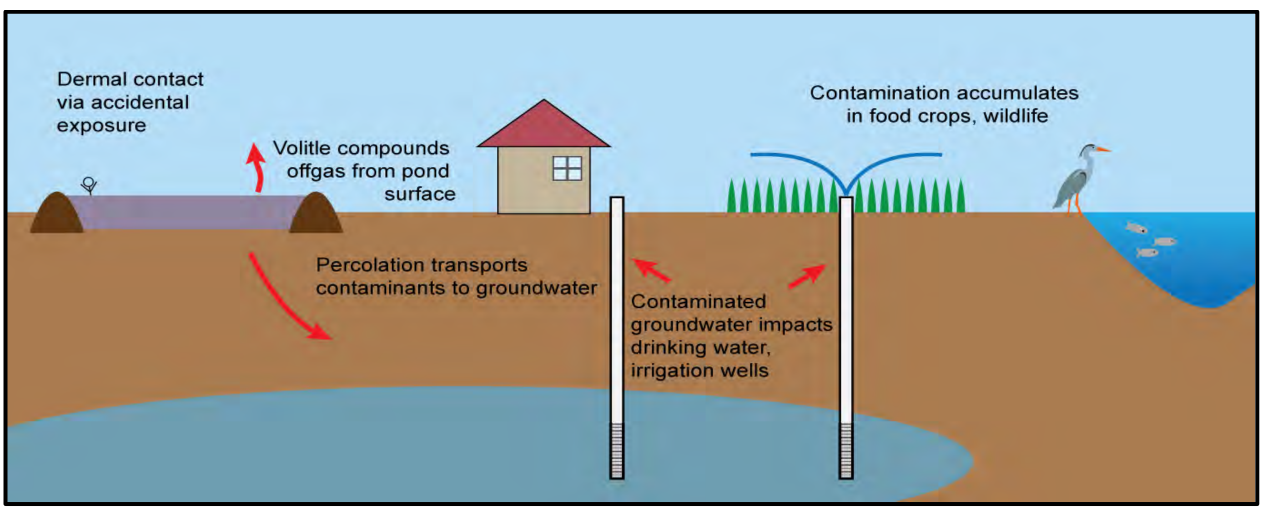

Figure 5.7. Conceptual contamination and exposure pathways associated with produced water disposal ponds.

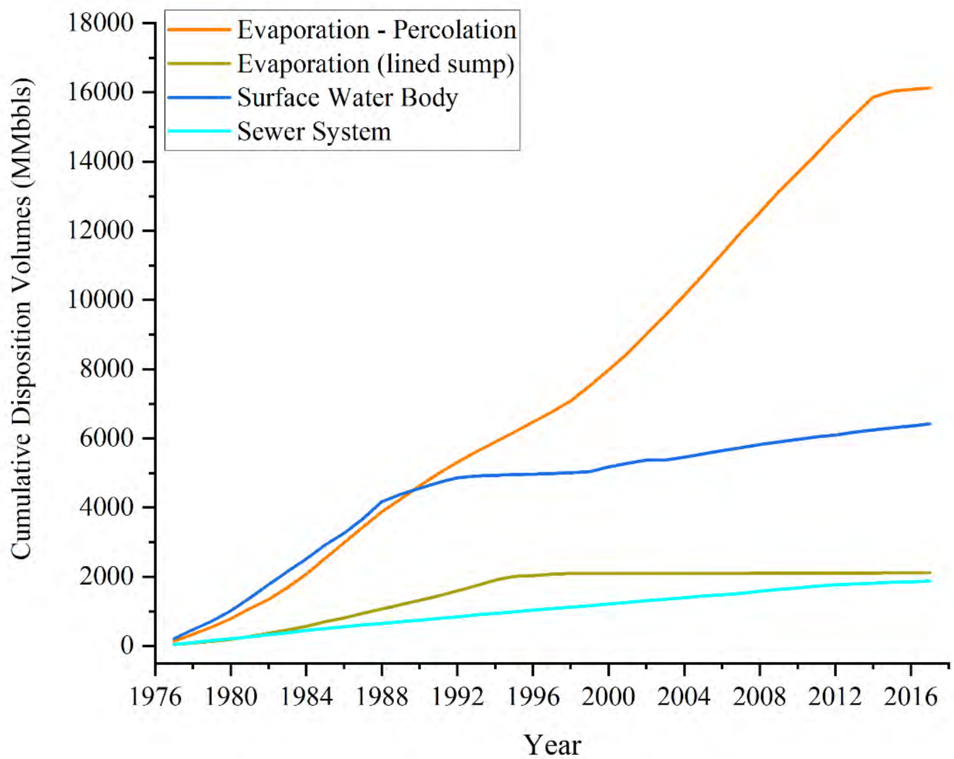

Figure 5.8. Cumulative volumes of produced water discharged into unlined produced water ponds, lined produced water ponds, surface water, and sewer systems from 1977 to 2017. Source: Figure S5 from DiGiulio et al. (2021).

5.5.2. Regulatory Actions Relevant to Produced Water Ponds in California

The California Legislature and the CVRWQCB, the regulatory jurisdiction where most unlined produced water ponds are located, have undertaken numerous regulatory actions to better control and understand the risks posed to groundwater resources and public health from the disposal of produced water into unlined produced water ponds.

In September 2013, the California Legislature passed Senate Bill 4 (SB 4), setting the framework for regulation of well stimulation technologies in California, including hydraulic fracturing (California Senate Bill No. 4, 2013). SB 4 required full disclosure of the composition of well stimulation fluids which could be present to some degree in produced water from stimulated wells. SB 4 also required the SWRCB to implement Regional Groundwater Monitoring Programs (RMPs) prioritizing monitoring of groundwater that has the potential to be a source of drinking water including from impact by well stimulation, UIC wells, and produced water ponds. The USGS, through funding from the SWRCB, is the technical lead on implementing RMPs (SWRCB, 2021a).

In May 2014, the CVRWQCB began an effort to better regulate the disposal of produced water into unlined produced water ponds (CVRWQCB, 2014). The CVRWQCB located 326 facilities with 1,100 produced water ponds that receive or had received produced water in the Tulare Basin (CVRWQCB, 2017). At 241 of these 326 (~74%) facilities, produced water was being discharged to produced water ponds without Waste Discharge Requirements (WDRs) required for operation.

At the remaining 85 facilities (~26%), wastewater was being discharged to produced water ponds under WDRs that were 20 years old or older. The CVRWQCB subsequently issued Notices of Violation to numerous facility operators not having WDRs (CVRWQCB, 2017, 2017a, 2017b).

In September 2014, the California Legislature passed Senate Bill 1281 (SB 1281) requiring improved reporting on the volume, characteristics, treatment, and disposition of produced fluids from any well to the California Department of Oil, Gas, and Geothermal Resources (DOGGR, now CalGEM) starting with the first quarter of 2015 (California Senate Bill No. 1281, 2014). CalGEM had previously used six category codes (including discharge to lined and unlined sumps) to track the disposition of produced water in California. Subsequently, this number increased to 12 category codes, including discharge to land surface and “domestic use” which includes irrigation (CalGEM, 2018).

SB 1281 does not mandate the tracking of waste products associated with the handling and management of produced water (e.g., filter socks, sludge from settling tanks, scale from pipes). It is unclear how these waste products are tracked in California, which agencies having jurisdiction for waste management, and the degree of fragmentation of waste management. For instance, while CalGEM may have jurisdiction for sludge management in oil-water separators, a regional water board may have jurisdiction for sludge management in produced water ponds. SB 1281 also does not mandate tracking the destination of produced water. Hence, produced water from a particular well or field cannot be traced to a produced water pond facility discharge point. Pursuant to SB 1281, CalGEM is required to provide the SWRCB with an “inventory of all unlined oil and gas field sumps” (California Senate Bill No. 1281, 2014).

Characterization of produced water under SB 1281 is limited to a determination of whether concentrations of TDS are greater or less than 10,000 mg/L (binary yes or no response). Prior to 2014, the CVRWQCB required determination of electrical conductivity, boron, and chloride concentrations in produced water discharged to produced water ponds. These constituents were monitored in order to evaluate compliance with the Tulare Basin Water Quality Control Plan effluent limitations (1,000 microSiemens per centimeter (µS/cm), 200 mg/L, and 1 mg/L, respectively) (CVRWQCB, 2018). Limits do not exist for other constituents present in produced water, such as heavy metals, radionuclides, and volatile organic compounds such as benzene, toluene, ethylbenzene, and xylenes (BTEX).

In May 2015, the CVRWQCB issued a directive pursuant to the California Water Code Section 13267 to 77 facility operators expanding chemical analysis of produced water discharged into ponds to major ions (e.g., sodium, potassium, calcium, magnesium, sulfate, chloride, bicarbonate, carbonate, hydroxide); target metals (e.g. chromium, nickel); trace metals (e.g., lithium, strontium); arsenic; petroleum hydrocarbons; polyaromatic hydrocarbons (PAHs); target VOCs (e.g., benzene, toluene, ethylbenzene, xylenes); and radionuclides (radium-226, radium-228, gross alpha) (CVRWQCB, 2015).

In June 2015, the California Legislature passed SB 83, which in part required that the SWRCB issue a status report (“Produced Water Pond Status Report”) on the regulation of oil field produced water ponds within each region by January 30, 2016, and every six months thereafter (California Senate Bill No. 83, 2015).

In April 2017, the CVRWQCB developed three general orders to facilitate the permitting of unlined produced water ponds. In areas where groundwater with beneficial use exists, General Order Number One applies to discharge facilities where wastewater effluent can meet the discharge requirements of the Tulare Lake Basin Plan (CVRWQCB, 2017), whereas General Order Number Two applies to discharge facilities where wastewater effluent cannot meet Tulare Lake Basin Plan discharge requirements (CVRWQCB, 2017a). Both general orders require quarterly chemical monitoring of produced water discharged into produced water ponds, and the installation of at least three monitoring wells in the vicinity of produced water ponds (CVRWQCB, 2017, 2017a). General Order Number Three applies to facilities where wastewater effluent exceeds the Tulare Lake Basin Plan effluent requirements, and where first encountered groundwater is associated with commercial oil and gas production or where natural background groundwater quality does not have beneficial use (CVRWQCB, 2017b).

In October 2017, the California Legislature passed Assembly Bill (AB) 1328 authorizing RWQCBs to require and make public information about chemicals added to produced water if discharged to surface or land (California Assembly Bill No. 1328, 2017). AB 1328 addressed the concern that there are numerous additives such as surfactants, solvents, and biocides used during oil and gas extraction that are not subject to target analyses at commercial laboratories routinely used to test produced water. Quarterly or semiannual reports on discharge of produced water to produced water ponds must now contain this information.

In July 2018, CalGEM commissioned a study to better understand reporting pursuant to SB 1281. DiGiulio and Shonkoff (2021) found that treatment of produced water prior to discharge in the Tulare Basin was limited to de-oiling (94.86%); de-oiling with other treatment (0.25%); no method specified (2.06%); and no treatment (2.83%). DiGiulio and Shonkoff (2021) also found that reporting pursuant to SB 1281 indicated that ~96% of produced water disposed in unlined produced water ponds in the Tulare Basin between 2015 and 2017 exceeded 10,000 mg/L TDS.

Finally, to better understand emissions of VOCs from produced water ponds, in May 2020, the California Air Resources Board (CARB) released a report on VOC emissions from produced water ponds in California (Schmidt & Card, 2020).

5.5.3. Chemical Characterization of Produced Water Disposed in Produced Water Ponds

USGS reports have summarized produced water composition from several oil and gas fields in California (**Table 5.1**). However, there is no counterpart which describes the disposition of waters contained in produced water ponds. Few peer-reviewed studies have characterized the chemical constituents of produced water contained within individual ponds in California (e.g., McMahon et al., 2018, 2019). This is a crucial knowledge gap, as both produced water treatment methods, along with shifts in geochemical setting (i.e., changes in redox status, evapoconcentration) during storage within percolation ponds, make it relatively likely that the chemistry of produced waters do not reflect the chemistry of pondwaters. To address this knowledge gap, publicly available data contained within the SWRCB Geotracker system (SWRCB, 2021b) were extracted and summarized.

The Geotracker website contains chemical data of samples collected from produced water ponds at a variety of timescales (e.g., quarterly, annually). For some facilities, and in relatively recent years, chemical data is provided electronically and can be downloaded directly in a digitized format (e.g., a comma separated value file). However, the vast majority of the data is contained within undigitized PDF format documents, necessitating manual retrieval from analytical reports. Data sets from the Tulare Basin were extracted from analytical reports dated prior to December 31, 2019.

In general, large produced water pond facilities had more sample data than small facilities. Hence, summary statistics presented here (**Table 5.5**) are biased toward large facilities. However, most produced water disposed in unlined produced water ponds is associated with large facilities. Thus, the summaries presented here are generally representative of the chemistry of produced water ponds on a statewide basis.

To assess the accuracy of the measured major cations and anions, a charge balance error was calculated for each sample. However, data points were not removed because large (>7%) charge imbalances were often due to a missing major ion analyte. All results that were reported as zero, a non-detection qualifier (e.g., “ND”), below a detection/reporting limit (e.g., “<0.05”), or negative were not considered in summary statistics. Detection limits for organic compounds were highly variable, complicating calculation of median and quartile values. In instances where a substantial fraction of analyses resulted in non-detection, there may be an upper bias estimation in quartile and median concentrations for organic compounds.

There is considerable spatial variability in the composition of produced water disposed in produced water ponds throughout the Tulare Basin. High concentrations of salts and BTEX components in produced water disposed in unlined produced water ponds generally occurs in the western and southwestern portion of the Tulare Basin (DiGiulio et al., 2021).

Chloride and boron are the most commonly measured (n>1,400) constituents across the database. The frequent measurement of chloride and boron is unsurprising, as measurement of these constituents is required by the Tulare Basin Water Quality Control Plan (CVRWQCB, 2018). Specific conductance or electrical conductivity was measured less frequently despite also being required under the basin plan. Major ions (calcium, magnesium, potassium, sodium, bicarbonate, and sulfate) and pH are the next most measured constituents (n>900). Most detections of analytes beyond electrical conductivity, TDS, chloride, and boron are from measurements made after the CVRWQCB expanded the list of required analytes in 2015 (CVRWQCB, 2015).

Several constituents of concern in the database exceed regulatory limits. Both median and maximum levels of electrical conductivity, chloride, and boron in produced water disposed in unlined ponds exceed allowable effluent limitations in the Tulare Basin Plan (**Figure 5.9**). Concentrations of other major ions (e.g., sodium), are also high. Elevated levels of salts in produced water can salinize groundwater resources having potential domestic, municipal, and agricultural use. High levels of total organic carbon reflect the presence of dissolved hydrocarbons remaining in produced water after water-oil separation. Arsenic is the primary inorganic constituent of concern, with median and maximum concentrations of 26 and 380 µg/L, respectively. The majority (74%) of detected arsenic concentrations exceed the California Maximum Contaminant Level (CA MCL) of 10 µg/L (**Table 5.5**).

Table 5.5. Characterization of water quality data from sampled produced water ponds in the Tulare Basin contained in the SWRCB Geotracker website (SWRCB, 2021b). Constituents include general water quality parameters, major and minor ions, trace elements, radionuclides, isotopes, nutrients, and organics. California maximum contaminant levels (MCLs) for regulated drinking water contaminants provided for reference (SWRCB, 2023).

					Percentile				
Constituents (units)	**Detections (%)**	**Min**	**Med**	**Max**	**5th**	**25th**	**75th**	**95th**	**CA MCLs**
General Water Quality									
Alkalinity as $CaCO_3$ (mg/L)	938 (99.8)	45	1,000	6,700	160	690	1760	3,120	
Hardness as $CaCO_3$ (mg/L)	calculation	4.87	345	21,000	46	180	650	2,070	
Specific Conductance (µS/cm)	1,101 (100)	220	15,000	216,000	545	6,100	30,000	52,200	
Total Dissolved Solids (mg/L)	1,187 (100)	150	9,530	95,000	390	4,580	17,000	31,200	
Total Organic Carbon (mg/L)	290 (100)	0.9	58	750	4.7	32.2	98	297	
Total Suspended Solids (mg/L)	243 (87.7)	1.2	26	3,500	3.01	12	58	199	
pH (pH units)	1,123 (100)	5.04	7.63	11.7	6.38	7.22	8	8.45	
Major Ions									
Bicarbonate (mg/L)	1,331 (99.8)	54.9	1,460	8,430	190	854	2,480	4,700	
Carbonate (mg/L)	165 (17.1)	0.9	77	1,870	5.12	30.1	175	502	
Bromide (mg/L)	135 (94.4)	0.11	11	370	0.234	4.9	37.5	110	
Chloride (mg/L)	1,597 (99.8)	11	2,050	59,600	55	266	7,200	15,800	
Sulfate (mg/L)	1,190 (88.6)	0.46	110	6,410	5.14	34.6	450	1,560	
Calcium (mg/L)	1,345 (99.9)	0.8	64	2,700	8.62	33.2	130	437	
Magnesium (mg/L)	1,330 (99.3)	0.032	39	4,980	1.65	17.6	84	229	
Potassium (mg/L)	969 (100)	0.38	72.6	1,010	2.2	35	103	230	
Sodium (mg/L)	1,352 (100)	15	2,500	31,100	140	1,230	4,900	10,000	
Inorganics									
Boron (mg/L)	1,429 (99.8)	0.048	40	360	0.65	7.72	65	111	
Antimony (µg/L)	58 (7.8)	0.21	3	2,200	0.853	1.3	97	223	6
Arsenic (µg/L)	360 (49.7)	0.47	26	380	3.48	9.85	53.5	153	10
Barium (mg/L)	734 (96.1)	0.001	1.44	130	0.067	0.512	4	13	1
Beryllium (µg/L)	14 (1.9)	0.5	10.9	120	0.591	1.05	13	68	4
Cadmium (µg/L)	7 (1)	0.23	1	10	0.239	0.415	2	7.72	5
Chromium (µg/L)	112 (15.1)	0.014	4.85	580	0.623	2.6	12.2	60.4	50[1]
Chromium VI (µg/L)	39 (12.1)	0.07	6.7	480	0.413	2.75	19.5	103	
Cobalt (µg/L)	102 (13.7)	0.06	0.975	150	0.5	0.653	1.58	12.9	
Copper (µg/L)	234 (31.5)	0.37	4.05	1,600	1.3	2.5	13	337	1,300[2]
Iron (mg/L)	500 (74.6)	0.011	1.44	77.4	0.071	0.328	3.7	14.3	
Lead (µg/L)	53 (7.1)	0.15	15	1,700	0.564	2.4	41	384	15[2]

					Percentile				
Constituents (units)	**Detections (%)**	**Min**	**Med**	**Max**	**5th**	**25th**	**75th**	**95th**	**CA MCLs**
Lithium (mg/L)	377 (92.6)	0.015	0.93	33	0.12	0.63	2.5	6.9	
Manganese (µg/L)	397 (90.8)	2.6	120	1,900	19.2	77	230	671	
Mercury (µg/L)	213 (28.9)	0.018	0.12	65	0.032	0.06	0.34	7.02	2
Molybdenum (µg/L)	266 (35.9)	0.28	12	600	1.3	4.32	28.8	118	
Nickel (µg/L)	324 (43.7)	0.3	7.4	1,700	1.66	3.5	17.2	64.8	100
Selenium (µg/L)	337 (46.3)	0.28	32	950	4.32	19	87	290	50
Silver (µg/L)	34 (4.6)	0.3	13.5	300	0.694	7.82	20.8	124	
Strontium (mg/L)	580 (96)	0.041	3.38	120	0.15	1.5	7.91	17	
Thallium (µg/L)	4 (0.6)	0.2	279	580	34.7	173	391	542	2
Vanadium (µg/L)	81 (10.9)	1	9.9	640	1.6	6	36	200	
Zinc (µg/L)	343 (45.9)	1.8	39	3,900	5.72	15	75	199	
Silica (mg/L)	140 (96.6)	10	70.5	270	18	40.5	140	210	
Radionuclides/Isotopes									
Deuterium (per mil)	417 (100)	-98.7	-54.1	26	-68.5	-59.6	-47.1	-29.5	
Oxygen-18 (per mil)	416 (100)	-44.3	-4.89	11.4	-8.39	-6.06	-3.37	-0.83	
Gross alpha (pCi /L)	280 (95.2)	0.015	12.6	310	0.418	5.2	28.4	101	15
Gross beta (pCi /L)	142 (100)	0.033	61.6	440	1.8	31.1	110	242	4[3]
Radium-226 (pCi /L)	362 (95.8)	0.065	2.6	55.3	0.238	1.1	7.79	24.1	5[4]
Radium-228 (pCi /L)	312 (91.5)	0.001	3.92	67.6	0.109	1.1	8.13	22.7	5[4]
Uranium (µg/L)	87 (30.1)	0.102	1.3	39	0.143	0.57	2.99	18.8	20[5]
Nutrients									
Ammonia (mg/L)	233 (98.3)	0.13	49.9	194	1.33	24.7	93.9	152	
Ammonium (mg/L)	43 (100)	0.21	64.3	170	0.593	35.4	100	159	
Nitrate (mg/L)	126 (14.3)	0.03	2.58	85.8	0.077	0.29	13.4	55.2	10[6]
Total Kjeldahl Nitrogen (mg/L)	47 (100)	0.25	72	220	0.656	1.65	110	168	
Organics									
Oil & Grease (mg/L)	292 (94.2)	1.3	19	1,800	3.96	8.65	46.2	160	
Benzene (µg/L)	540 (57)	0.09	22	5,700	0.78	5.8	182	1,500	1
Toluene (µg/L)	570 (62)	0.1	38	5,990	0.375	7.65	240	1,950	150
Ethylbenzene (µg/L)	496 (52.4)	0.12	14.5	4,000	0.688	4.9	53	240	300
p- & m-Xylenes (µg/L)	483 (67.4)	0.27	20	14,000	0.606	6.55	120	710	
o-Xylene (µg/L)	483 (67.2)	0.1	15	6,700	0.412	4.3	69	389	
Total Xylenes (µg/L)	638 (68.5)	0.14	24.3	20,700	0.83	6.6	131	960	1,750
Naphthalene (µg/L)	289 (51)	0.061	6.1	340	0.26	1.4	19	145	

1. Total chromium
2. Regulatory action level
3. millirem per year (mrem/yr)
4. Radium 226 + 228
5. pCi/L
6. As nitrogen (N)

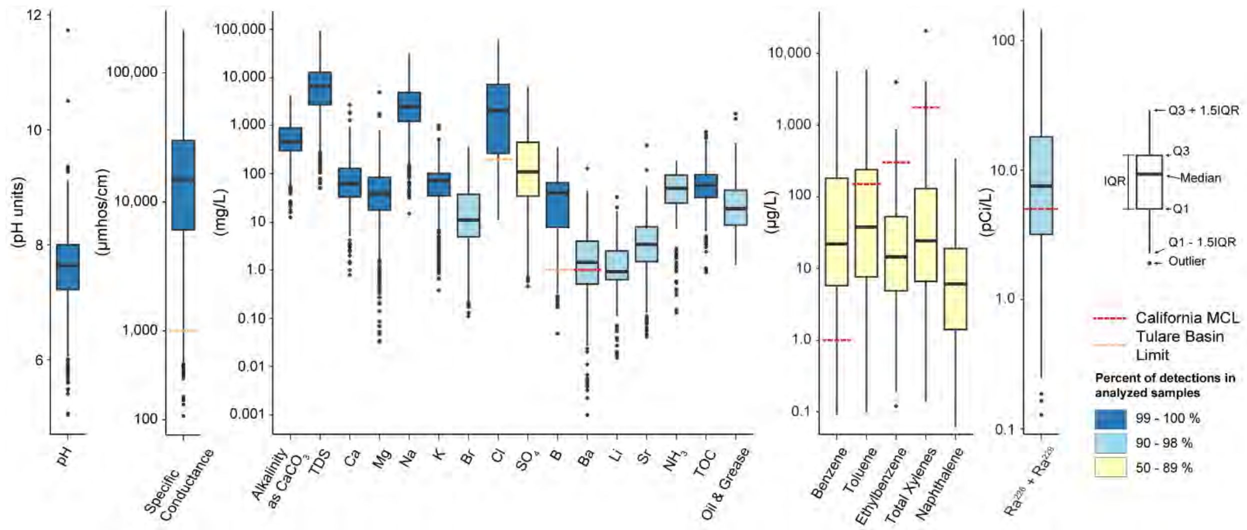

Figure 5.9. Boxplot of pH, conductivity, and other selected constituents and their relation to California regulatory limits for produced water disposal ponds, and drinking water (22 C.C.R. § 64431, 2021; 22 C.C.R. § 64442, 2021; 22 C.C.R. § 64444, 2021; CVRWQCB, 2018). Total xylenes are the maximum detected concentration of p-&m-xylenes, o-xylene, or total xylenes. Source: Figure 3 from DiGiulio et al. (2021).

Ammonium levels in produced water discharged to unlined produced water ponds are also quite high, with median and maximum levels of 64.3 and 170 mg/L, respectively. Both ammonia (which includes free ammonia and ammonium) and ammonium were often reported. Because the pH of water in most produced water ponds was near neutral, most ammonia was present as ammonium. A primary concern with high ammonium levels in produced water discharged in unlined ponds is nitrification. Unlike produced water coming directly from an oil and gas well, produced water in unlined ponds is oxic and can facilitate nitrification in subsurface media. The CA MCL for nitrate is 45 mg/L as nitrate or 10 mg/L as nitrogen. The CA MCL for nitrite is 1 mg/L. Because the toxicity of nitrate and nitrite are additive, the CA MCL for the sum of nitrate and nitrite as nitrogen is 10 mg/L, and only one of the detected sums of these constituents exceeds that level.

In comparison with produced water from shale formations (e.g., Marcellus, Utica), gross alpha, gross beta, radium-226, and radium-228 activities are relatively low in California's produced water ponds. However, despite being relatively low, the detected activities of these radionuclides are still concerning from a regulatory standpoint. Specifically, 58% of detected radium-226 + radium-228 activities meet or exceed the associated CA MCL (5 pCi/L) and 44% of detected gross alpha meets or exceeds the CA MCL (15 pCi/L). Radium mobilization from sediments near unlined produced water ponds has been observed in groundwaters associated with the Fruitvale, Lost Hills, and South Belridge oil fields (McMahon et al., 2019).

The median concentration of benzene in produced water discharged to produced water ponds (24 µg/L) is an order of magnitude higher than the CA MCL of 1 µg/L, while the median concentration of detected toluene, ethylbenzene, and total xylene concentrations are less than the associated CA MCLs (150, 300, and 1,750 µg/L, respectively) (**Figure 5.9**). However, the maximum detected levels of these constituents are well above the associated CA MCLs.

5.5.3.1 Emissions of Organic Compounds Produced Water Ponds

Relatively few studies have measured emissions of organic compounds from produced water disposal ponds, and thus there is a large knowledge gap surrounding this aspect of produced water disposal. Of the few studies that have measured emissions of these compounds (e.g., Lyman et al., 2018; Mansfield et al., 2018; Schmidt & Card, 2020; Thoma, 2009; Tran et al., 2018), only one has sampled produced water ponds in the California (Schmidt & Card, 2020). None of these studies measured transport distances of these compounds, and thus distances of impact are unknown.

Schmidt & Card (2020) analyzed a total of 95 samples from 25 disposal facilities. Of the sampled facilities only 19 utilized produced water disposal ponds, and thus a total of 89 samples were collected from produced water ponds. The aqueous sampling (**Table 5.6**) and vapor concentrations in flux chambers (**Table 5.7**) above produced water ponds provide additional information on concentrations of VOCs, especially BTEX components, and are another source of data for these constituents. In general, the lower bounds of the aqueous samples collected by Schmidt and Card (2020) (**Table 5.6**) agree with those in the Geotracker database (**Table 5.5**). However, the maximum detected values of BTEX compounds in the Geotracker data (**Table 5.5**) are generally 1–1.5 times those measured by Schmidt and Card (2020) **(Table 5.6**). Complete data for the aqueous and vapor samples collected by Schmidt and Card (2020) are provided in Appendix E.3.

Table 5.6. Summary of selected constituents of produced water pond aqueous samples. Source: Schmidt and Card (2020).

Constituents (units)	No. of Detections	Min	Med	Max	Percentile 5th	25th	75th	95th
Oil & Grease (mg/L)	94	1.4	13.5	660,000	2.95	7.13	28	537
Benzene (µg/L)	86	0.1	6	1,650	0.18	0.5	70.3	838
Ethylbenzene (µg/L)	84	0.11	6.45	1,600	0.22	0.95	34.3	688
Toluene (µg/L)	86	0.1	3.35	1,900	0.14	0.6	25.3	550
Total Xylenes (µg/L)	86	0.39	9.9	2,200	0.51	2.2	60.3	979
p- & m-Xylenes (µg/L)	85	0.29	5.7	1,400	0.4	1.3	40	629
o-Xylene (µg/L)	90	0.09	3.6	790	0.12	0.9	20.8	349

Table 5.7. Summary of selected constituents of produced water pond gases and vapors. Source: Schmidt and Card (2020).

Constituents (units)	No. of Detections	Min	Med	Max	Percentile			
					5th	25th	75th	95th
Total Non-Methane Hydrocarbons (C6 µg/m^3)	90	65.6	5,770	47,300,000	178	1,530	37,800	288,000
Total Non-Methane Hydrocarbons (C1 µg/m^3)	90	73	6,420	52,700,000	198	1,700	42,100	321,000
Benzene (µg/m^3)	88	1.47	56.7	125,000	2.94	10.1	342	11,800
Ethylbenzene (µg/m^3)	57	1.5	39.2	303,000	4.27	11.1	318	2,510
Toluene (µg/m^3)	75	0.92	55.7	574,000	2.93	9.94	571	19,800
m,p-Xylenes (µg/m^3)	62	1.1	84.2	579,000	2.98	16.4	602	9,120
o-Xylene (µg/m^3)	55	1.21	86.4	286,000	3.84	15.3	398	4,960
Total Xylene (µg/m^3)	71	0	86.3	865,000	0	10.3	739	13,200
Total BTEX (µg/m^3)	95	0	104	1,870,000	1.85	17.1	1,150	42,500
Carbon Dioxide (%)	40	0.01	0.05	0.41	0.02	0.02	0.13	0.32
Methane (ppmv)	88	0.47	11	1,350	1.18	2.67	117	487

Abbreviations: ppmv – parts per million by volume; µg/m^3 – micrograms per cubic meter

5.5.4. Number, Status, and Locations of Produced Water Ponds in the Tulare Basin

No individual publicly available State database accurately accounts for all produced water ponds in the Tulare Basin. DiGiulio et al. (2021) found major discrepancies between data sources in locating produced water ponds in the Tulare Basin. The authors catalogued a total of 1,784 produced water ponds in the Tulare Basin, of which 29 were used for mixing produced water with surface water and groundwater for agricultural irrigation. There were 1,317 ponds listed on the SWRCB Produced Water Ponds List, of which 511 were unique to this list; 311 ponds were listed in WellSTAR, of which 60 were unique to WellSTAR; and 1,213 ponds located on Geotracker, of which 407 were unique to Geotracker.

The discrepancy between identification of ponds on the SWRCB produced water pond list and Geotracker is due in part to a lack of identification of many closed produced water ponds on the SWRCB list. Other reasons for discrepancies between WellSTAR, Geotracker, and the SWRCB produced water pond list are unclear (DiGiulio et al., 2021). Precise information on location (latitude and longitude) was available for most (92.9%) ponds that were located. In Geotracker, there were 110 ponds that had only Public Land Survey System (PLSS) descriptions and 21 ponds that only had an oil and gas field identifier.

DiGiulio et al. (2021) also found that an unknown number of closed facilities remain unidentified. For example, while viewing produced water ponds on the Google Earth application of Geotracker, they noted the presence of three large inactive unlined produced water facilities west of the Belridge North field and one large inactive unlined produced water facility in the Midway-Sunset Field, cumulatively consisting of at least 95 unlined ponds not identified in any database. As such, we have included 95 unlined ponds as unidentified, although locations should be field verified as used for produced water disposal.

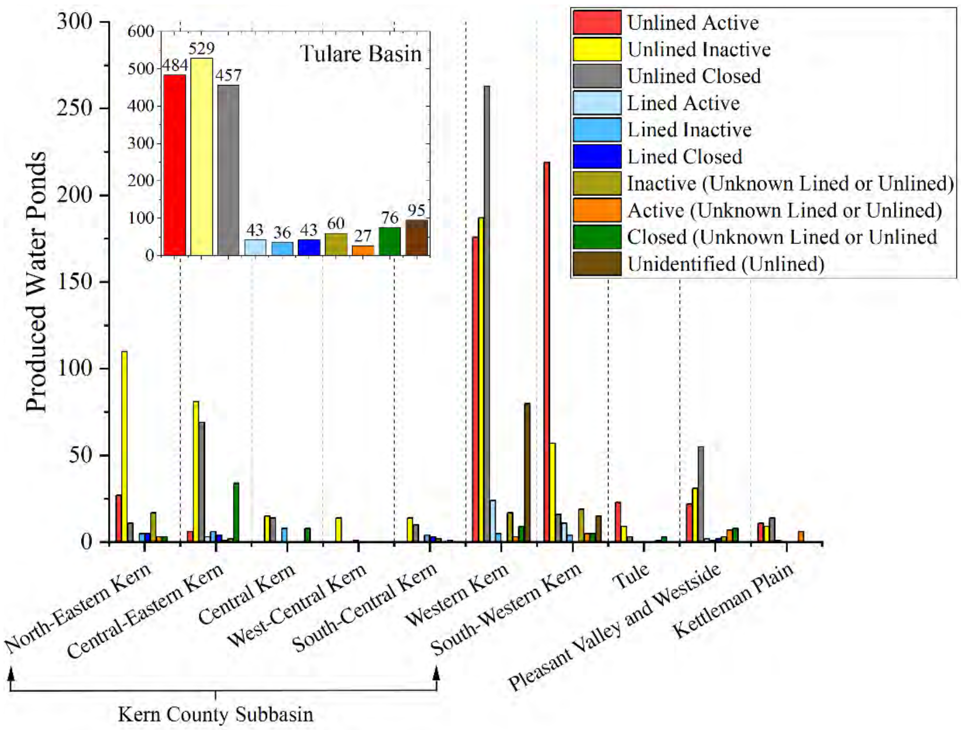

Figure 5.10. Summary and status of produced water ponds in the Tulare Basin. Source: Figure 2 modified from DiGiulio et al. (2021).

In summary, there appears to be at least 1,850 active, inactive, and closed ponds that were used exclusively to store or dispose produced water in the Tulare Basin (**Figure 5.10**). The status of ponds in WellSTAR were listed as active, idle, and removed. The latter two categories were assumed to refer to inactive and closed ponds. At least 85% (1,565) of ponds in the Tulare Basin are unlined, of which 31% (484) are still active. This is an underestimate of the number of unlined ponds, as the 60 unique WellSTAR entries contain no description of whether ponds are lined or unlined.

5.5.5. Exceedance of Effluent Limits in the Tulare Basin and Assessment of Potential Impact to Groundwater

The California Department of Water Resources (CDWR) created groundwater subbasins in California by dividing groundwater basins into smaller units using geologic and hydrologic barriers or, more commonly, institutional boundaries for the purpose of collecting and analyzing data and managing water resources (CDWR, 2021). Subbasins in the Tulare Basin are used here to describe locations where unlined produced water ponds overlie groundwater with municipal or agricultural beneficial use, and where impact to groundwater has been documented. A list of oil and gas fields associated with each subbasin is provided in Appendix E.4.

The disposal of produced water having high levels of electrical conductivity, chloride, and boron into unlined produced water ponds exceeding the Tulare Basin effluent limits has occurred and continues to occur in many areas of the Tulare Basin overlying groundwater resources. Groundwater monitoring at unlined produced water pond facilities is relatively sparse, but where monitoring has occurred, impact to groundwater has been observed and has proven too expensive to actively remediate. Hence, the practice of disposing produced water into unlined ponds can cause permanent damage to groundwater resources. Also, impact to groundwater has occurred at distances greater than 4 km (2.5 mi) from unlined ponds. Given demonstrated cases of impact to groundwater, unlined produced water ponds should not be located hydraulically upgradient of domestic, municipal, and agricultural water supply wells.

5.5.5.1 Counts of Unlined Ponds and Exceedances of Tulare Basin Effluent Limits in Basin Sub Areas

DiGiulio et al. (2021) found most unlined produced water ponds in California were located in the Kern County Subbasin (**Figure 5.11**). As such, this area, and counts of unlined ponds in particular, are the focus of discussion here. Complete counts of all types of produced water disposal ponds within each geographic area of the SJV are provided in Table E.4.

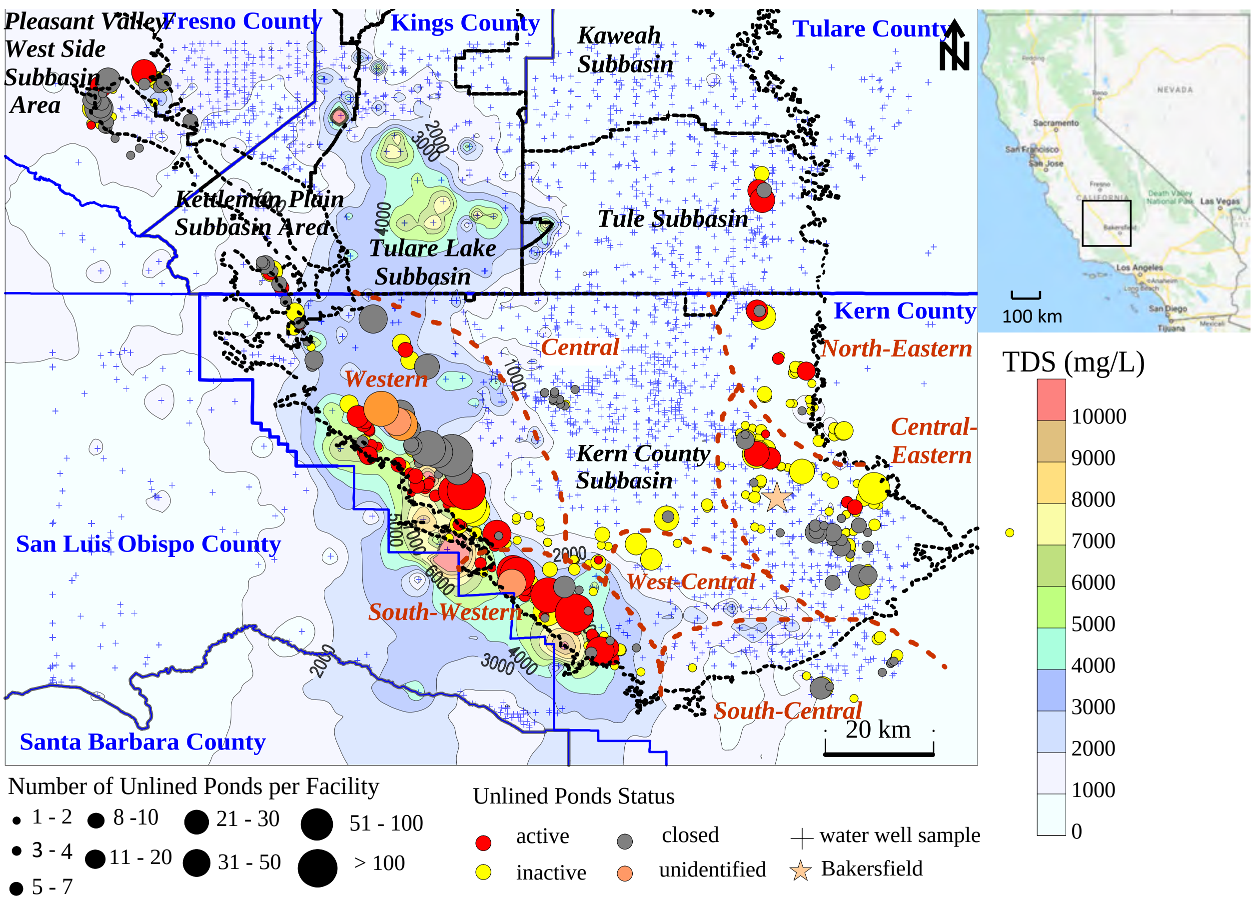

Figure 5.11. Interpolated levels (contour lines) of total dissolved solids (TDS) in groundwater from water well samples and the location of active, inactive, and closed unlined produced water pond facilities in subbasins within the Tulare Basin in the southern portion of the San Joaquin Valley. Source: Figure 1 from DiGiulio et al. (2021).

In the northeastern area of the Kern County Subbasin (148 unlined ponds, of which 27 are active) (Table E.4), levels of TDS in groundwater are generally <1,000 mg/L (**Figure 5.11**). While median levels of electrical conductivity, chloride, and boron of produced water discharged to ponds at facilities in this area were generally within the Tulare Basin effluent limitations, maximum levels of electrical conductivity, chloride, and boron indicate periodic exceedance of these standards (DiGiulio et al., 2021). Additionally BTEX compounds other than benzene were detected in produced water discharged to ponds (DiGiulio et al., 2021).

In the central-eastern area of the Kern Subbasin (156 unlined ponds, of which six are active) (Table E.4), TDS levels in water wells are generally <1,000 mg/L (**Figure 5.11**). Median levels of electrical conductivity, chloride, and boron of produced water discharged to ponds in this area were generally above the Tulare Basin effluent limitations, with maximum levels of electrical conductivity, chloride, and boron indicating significant exceedances of these standards (DiGiulio et al., 2021). Benzene was detected in produced water discharged to ponds at a maximum concentration of 2,410 µg/L (DiGiulio et al., 2021).

Relatively few produced water ponds are in the south-central (24 unlined ponds), central (29 unlined ponds), and west-central (14 unlined ponds) portions of the Kern Subbasin, and no unlined ponds are active in this area (Table E.4). In all of these areas, groundwater having TDS levels <3,000 mg/L is present (**Figure 5.11**). DiGiulio et al. (2021) did not find any pond effluent data in this area. Given the lack of active unlined disposal ponds in these areas, the primary concern is potential groundwater contamination from legacy ponds.

The western portion of the Kern Subbasin has the largest number of produced water ponds (626 unlined ponds, of which 176 are active) in the Tulare Basin (**Figure 5.11**, Table E.4). Most produced water ponds in this area lie directly east of oil and gas fields where there is a transition from brackish groundwater (TDS 3,000–10,000 mg/L) to fresher (TDS <3,000 mg/L) groundwater from west to east (**Figure 5.11**), toward the synclinal axis of the San Joaquin Valley (DiGiulio et al., 2021). Produced water disposed in unlined ponds in this area far exceeds the Tulare Basin effluent limits. BTEX compounds were consistently detected in produced water disposed in ponds in this area with a maximum concentration of benzene at 5,700 µg/L (DiGiulio et al., 2021).

Most active unlined ponds (292 ponds, of which 219 are active) are within the southwestern portion of the Kern Subbasin (**Figure 5.11**, Table E.4). Like the western portion of the Kern Subbasin, produced water disposed in unlined ponds in this area far exceeds the Tulare Basin effluent limits, and BTEX compounds were consistently detected in produced water disposed in ponds in this area, with a maximum concentration of benzene at 3,600 µg/L (DiGiulio et al., 2021).

5.5.5.2 Documented Impacts to Groundwater in the Tulare Basin

DiGiulio et al. (2021) primarily documented impacts to groundwater in the western portion of the Kern Subbasin (**Figure 5.12**), where the authors mainly found groundwater monitoring was occurring. However, impacts to groundwater near the Race Track Hill facility in the Edison Field (the only field in the eastern SJV where DiGiulio et al. (2021) found groundwater monitoring was occurring) near Bakersfield were also observed (**Figure 5.12**). Thus, impacts to groundwater via unlined disposal ponds appear to be possible anywhere that this practice has happened, or is currently happening, and any geographic heterogeneity is likely more a function of the location of monitoring infrastructure rather than other drivers (e.g., hydrogeologic setting, geochemical).

DiGiulio et al. (2021) found levels of electrical conductivity, TDS, chloride, and boron in impacted wells to range anywhere from two times to as much as ~46 times those in unimpacted wells (**Figure 5.13**). The only disagreement to this trend were boron levels in monitoring wells downgradient of the S.E. Taft Old and New facilities, which were two times higher in the unimpacted wells. However, after discounting outliers (i.e., values falling outside of the third quartile plus or -1.5 times the interquartile range), levels of these constituents in impacted wells range from two times to 19 times higher, and on average are ~6.5 times higher than those in the unimpacted wells. Using the elevated levels of electrical conductivity, TDS, chloride, and boron, DiGiulio et al. (2021) documented the distances at which produced water disposal facilities impacted groundwater. The distances of impacts range from anywhere to as little as less than 0.5 km (0.3 mi) to as much as greater than 4 km (2.5 mi) (**Table 5.8**). With the exception of the Race Track Hill facility (**Table 5.8**), groundwater was impacted at distances more than 1 km (3,281 ft) from produced water disposal pond facilities.

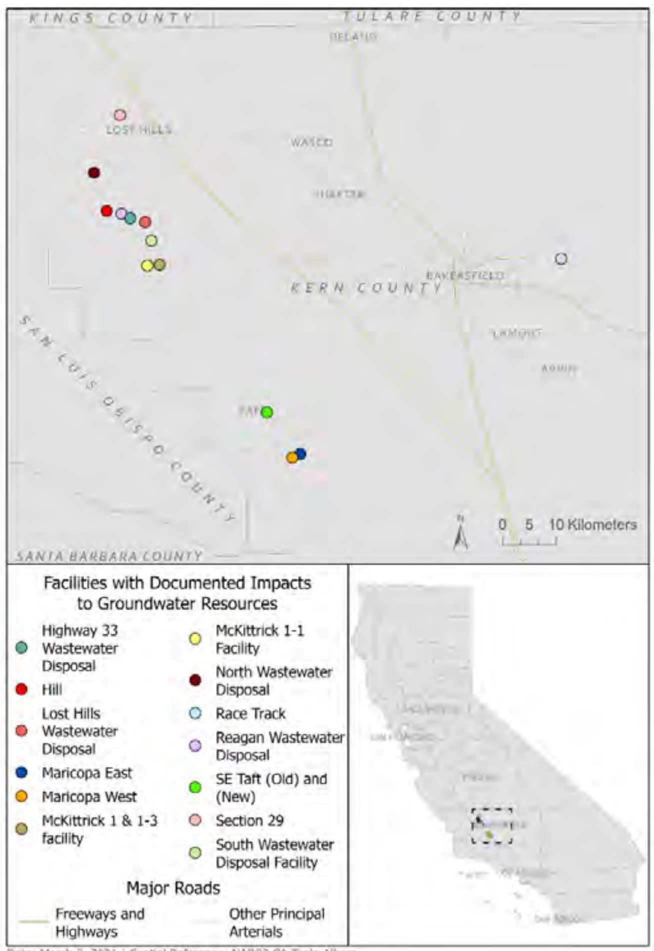

Figure 5.12. Locations of produced water pond facilities where groundwater monitoring indicates impact. Source: Figure 4 modified from DiGiulio et al. (2021).

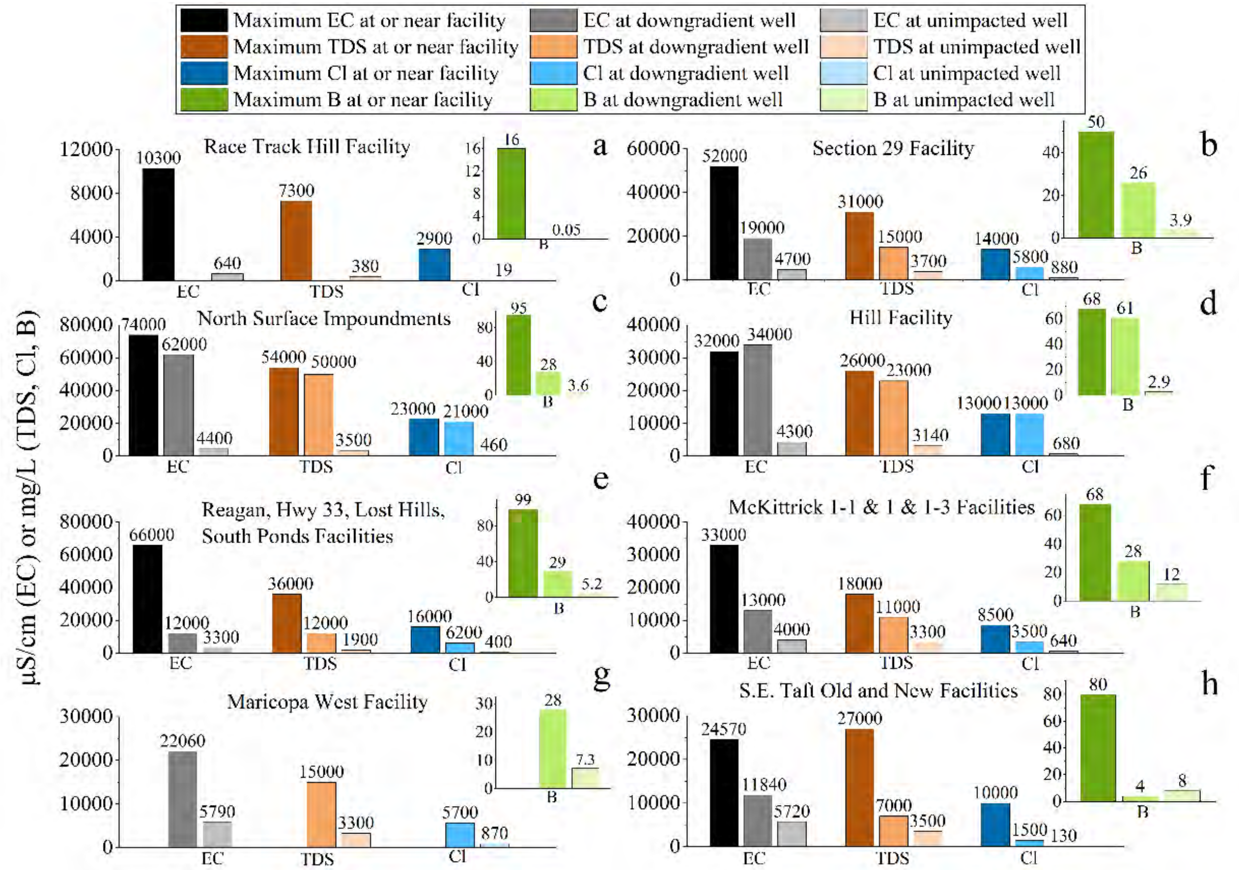

Figure 5.13. Concentrations of electrical conductivity (EC), total dissolved solids (TDS), chloride (Cl), and boron (B) (inset) in groundwater monitoring wells at facilities with an impact to groundwater. Downgradient and unimpacted monitoring wells are located more distant from a facility in the direction of groundwater flow. Source: Figure 5 from DiGiulio et al. (2021).

Table 5.8. Maximum concentrations of benzene, toluene, ethylbenzene, total xylenes, and the distance downgradient of facilities at which groundwater monitoring wells indicate an impact to groundwater.

Facility Name	Associated Field	Max Benzene (µg/L)	Max Toluene (µg/L)	Max Ethylbenzene (µg/L)	Max Xylenes (µg/L)	Distance of impact
Race Track Hill	Edison	<0.50	67	<0.50	<0.50	<0.5 km (0.3 mi)
Section 29	Lost Hills	47	5.7	0.26	3.1	>1.7 km (1.1 mi)
North Surface Impoundments	Belridge North	360	<2.0	<2.0	15	>1.5 km (0.9 mi)
Hill	Belridge South	84	140	28	140	>1.4 km (0.9 mi)
Reagan, Hwy 33, Lost Hills, South Ponds	Belridge South	3.7	43	13	NA	>4 km (2.5 mi)
McKittrick 1-1 and McKittrick 1 & 1-3	Cymric	1.6	7.0	<0.25	<0.25	>2 km (1.2 mi)
Maricopa West	Midway Sunset	<2.0	<2.0	<2.0	<2.0	>1.2 km (0.75 mi)
S.E. Taft Old and New	Midway Sunset	<2.0	<2.0	<2.0	<2.0	>1.2 km (0.75 mi)

In addition to elevated levels of electrical conductivity (EC), TDS, chloride, and boron, DiGiulio et al. (2021) also observed BTEX compounds and other hydrocarbons in monitoring wells near disposal facilities (**Table 5.8**). For example, BTEX compounds and other hydrocarbons (e.g., naphthalene, methyl naphthalenes, trimethylbenzenes) were detected in monitoring well samples near the closed Section 29 Facility (**Figure 5.12, Table 5.8**). At the nearby Lost Hills facility (**Figure 5.12**) Karolytė et al. (2021) demonstrated the presence of surface disposed produced water in groundwater using noble gas isotope ratios, although benzene concentrations (0.87 µg/L) were less than both the CA MCL and the U.S. EPA MCL (1 and 5 µg/L, respectively). Both Karolytė et al. (2021) and DiGiulio et al. (2021) detected benzene (15.1 µg/L) in a monitoring well east of the McKittrick 1-1 and McKittrick 1 & 1-3 Facilities (**Figure 5.12**). Karolytė et al. (2021) utilized noble gas isotope mixing ratios to demonstrate the nearby McKittrick disposal ponds were the likely surface source of produced water. The highest benzene concentrations (360 µg/L) observed in monitoring wells by DiGiulio et al. (2021) (**Table 5.8**) were located near the North Surface Impoundments Facility (**Figure 5.12**). While most organic compounds were below detection near the Race Track Hill facility, DiGiulio et al. (2021) observed a maximum detectable concentration of toluene at 67 µg/L, which they attributed to the disposal of produced water into unlined ponds and spray irrigation (**Table 5.8**).

5.5.5.3 Potential Impacts to Groundwater in the Tulare Basin

In January 2015, an independent scientific study on well stimulation in California commissioned by the California Natural Resources Agency concluded that the disposal of produced water in unlined produced water ponds posed a risk to groundwater resources. The report recommended that produced water discharged to these ponds should contain non-hazardous concentrations of chemicals or their use should be phased out in the future (Jordan et al., 2015; Stringfellow et al., 2015). The report stated further that groundwater investigations should be conducted to determine if historical disposal activities have impacted groundwater resources in the vicinity of these produced water ponds (Jordan et al., 2015).

The recent comprehensive assessment of unlined produced water ponds in the SJV by DiGiulio et al. (2021) bolsters this recommendation. Their investigation also supports a recommendation that the definition of protected groundwater during disposal of produced water into produced water ponds should be consistent with the definition of protected groundwater used in California's UIC program and for hydraulic fracturing. This inconsistency appears to be a major driver for this disposal practice, especially in the western and southwestern portion of the Kern Subbasin or Tulare Basin.

Further research would help determine whether individual groundwater plumes from large, closely spaced, historical, and active facilities in the western portion of the Kern Subbasin are in the process of forming "mega" plumes moving eastward toward the synclinal axis of the SJV and toward numerous irrigation and public water supply wells.

5.5.6. Populations Living Near Produced Water Infrastructure

As previously discussed, produced water potentially poses numerous health hazards (e.g., exposure to carcinogens) to human beings, and these hazards may occur via multiple exposure pathways (groundwater, air, etc.). A proximity analysis was conducted to quantify the number of people potentially at risk from produced water ponds (detailed in Chapter 7). To better constrain populations that may be impacted by legacy water disposal activities, the total number of individuals near a pond of any status (active, idle, or closed) and water disposal wells were also calculated (**Figure 5.14**; Table E.5, Appendix E.5). In general, roughly 545,000 Californians live within 1 km (3,281 ft) of an active, inactive, or historical produced water pond. About 168,000 Californians live within 1 km (3,281 ft) of an active pond, slightly less than the ~261,000 Californians that live within 1 km (3,281 ft) of a water disposal well (**Figure 5.5**). While these counts provide an approximation of populations that could be impacted by surficial processes (i.e., suspension of legacy contaminated sediments or air emissions from active infrastructure), this estimate does not fully capture populations that may be impacted by subsurface processes.

Fully constraining the risk of exposure to populations via subsurface pathways relies on two factors: (1) having knowledge of the spatial distribution of drinking water wells; and (2) understanding the subsurface geochemistry and hydrogeology. Locations of wells in California are relatively poorly constrained using publicly available data. Due to privacy concerns, coordinates of drinking water wells are logged as the centroid of the PLSS sections, and as such the spatial accuracy of these coordinates range from ± 142 m (467 ft) to ± ~1,140 m (3,729 ft) (Johnson & Belitz, 2015). As this range spans nearly all of the considered buffer distances, counts using these distances would be highly speculative and likely miss a substantial amount of residents relying on groundwater. Furthermore, while there is a large volume of literature supporting the inclusion of the buffer distances used to consider air emissions (see Chapter 7), their selection is likely more arbitrary for considering subsurface impacts.

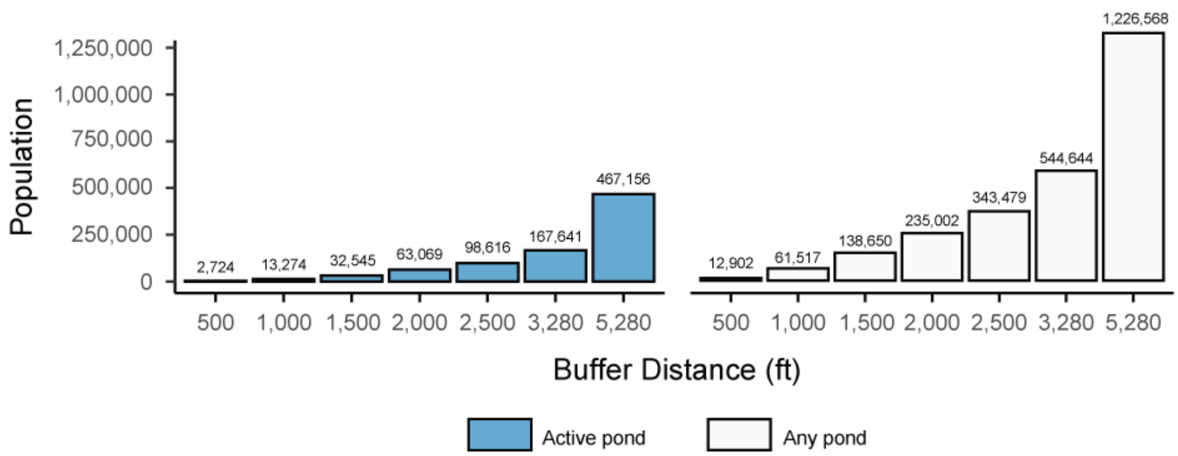

Figure 5.14. Total populations living within buffer distances of both active, and any status produced water disposal ponds.

As previously discussed, subsurface transport of contaminants has been observed anywhere from 0.5 km (1,640 ft) to greater than 4 km (2.5 mi) from pond facilities, thus the buffer distances that are appropriate for airborne contaminants would likely not completely identify groundwater receptors. Additionally, subsurface contaminant transport is mediated by both geochemical and hydrological conditions, both of which can be highly heterogeneous over relatively small spatial areas. Furthermore, current land use practices, which are also quite diverse, can enhance or retard subsurface contaminant transport. Consequently, transport distances are likely equally disparate. Thus, drinking water wells were not considered in this analysis, and future research efforts could be devoted to this topic to fully constrain the risk produced water ponds pose to communities relying on groundwater resources.

5.5.7. Available Information on Setbacks from Produced Water Management Facilities at Other States.

In Colorado, after January 15, 2021, operators must design, construct, and operate pits that are within 2,000 ft (610 m) of an existing building unit or designated outside activity area to emit less than 2 tons per year (tpy) VOCs (COGCC Rule 903.d(6)A.i, 2021). In highly populated counties (Adams, Arapahoe, Boulder, Broomfield, Denver, Douglas, Jefferson, Larimer, and Weld), pits must emit less than 2 tpy VOCs regardless of distance to existing buildings (COGCC Rule 903.d(6)A.ii, 2021). Otherwise, pits must emit less than 5 tpy VOCs. Operators cannot construct new Centralized Waste Management Facilities (large pit facilities) within 2,000 ft (610 m) of the nearest Building Unit or High Occupancy Building Unit, unless all Building Unit owners and tenants within 2,000 ft (610 m) consent to a closer location (COGCC Rule 907.b(5)G, 2021).

In Utah, a disposal facility must be located a minimum of 1 mi (1.6 km) from residences or occupied buildings not associated with the facility unless a waiver has been signed by the owners of the residences and buildings within one mile (Utah Admin. Code R649-9-3.3.2, 2013) or within 500 ft (152 m) of a wetland, water-course or lakebed (Utah Admin. Code R649-9-3.4.1, 2013).

5.6. Exposure Pathways from the Discharge of Produced Water to Surface Water

Humans may contact radionuclides, metals, organic compounds, or degradation products of organic compounds associated with the discharge of produced water through multiple exposure pathways. These include: dermal contact during swimming; ingestion via drinking water intake; incidental ingestion during swimming; inhalation and dermal contact during bathing and showering; consumption of fish, crops, or livestock that have bioaccumulated produced water contaminants; inhalation of volatile compounds from surface water; and inhalation of dust from ephemeral stream beds (**Figure 5.15**).

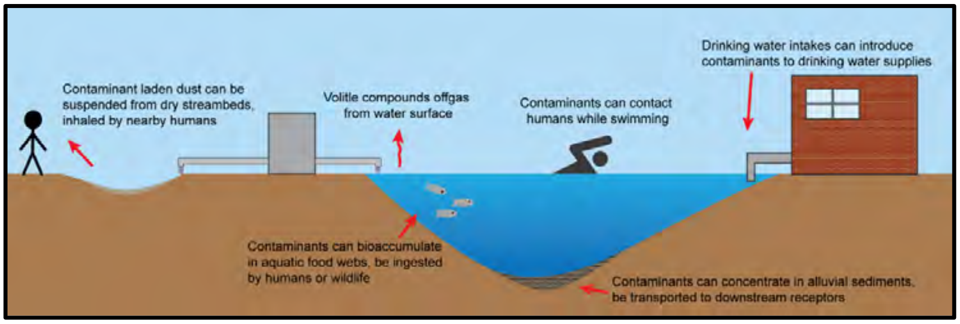

Figure 5.15. Conceptual pathways of surface discharges of produced water.

Produced water can be directly discharged to surface water or indirectly discharged to surface water through publicly owned treatment works (POTW). Any discharge of pollutants to surface waters must obtain authorization to discharge (i.e., a National Pollutant Discharge Elimination System permit) (US EPA, 2020). Under 40 Code of Federal Regulations (C.F.R.) 435 Subpart C, the direct onshore discharge of produced water to surface water must meet an Effluent Limitation Guideline (ELG) of "zero discharge" of pollutants (US EPA, 2020), essentially resulting in a prohibition of direct discharges of produced water to surface water. However, 40 C.F.R. § 435 Subpart C allows indirect discharges of produced water to surface water through POTWs, and does not specify pretreatment standards (US EPA, 2020). In 2016, the US EPA prohibited the indirect discharge of produced water from unconventional wells to POTWs (81 Fed. Reg., 2016). Disposal of produced water into sanitary sewer systems had occurred in fields where production wells have been stimulated (e.g., Wilmington Oil Field in Los Angeles County and a small amount from the Lost Hills Oil Field and Midway-Sunset Oil Field in Kern County) (Stringfellow et al., 2015).

Produced water can be directly or indirectly discharged to surface water under 40 C.F.R. § 435 in Subparts E, F, and H (US EPA, 2020). Under 40 C.F.R. § 435 Subpart E, produced water can be discharged directly to surface water if production wells are located west of the 98th meridian and produced water "is of good enough quality to be used for wildlife or livestock watering or other agricultural uses and that the produced water is actually put to such use during periods of discharge" (US EPA, 2020). The ELG for discharge under 40 C.F.R. § 435 Subpart E is limited to an oil and grease concentration ≤35 mg/L (US EPA, 2020). Under 40 C.F.R. § 435 Subpart F, produced water can be discharged directly to surface water if production wells produce ≤10 barrels of crude oil per day (i.e., stripper wells) (US EPA, 2020).

The direct discharge of produced water to surface water in California reached a peak in 1988 with discharge of 497.2 MMbbls (18.9% of produced water disposition) and a low in 2002 with a discharge of 2.2 MMbbls (0.1% of produced water disposition). In 2017, 58.9 MMbbls of produced water was discharged directly to surface water (1.8% of produced water disposition) (**Figure 5.3**). Cumulative direct disposal to surface water from 1977 to 2017 was 6,424 MMbbls, second only to disposal in unlined produced ponds for surface disposal methods (**Figure 5.3**). Hence, disposal to surface water continues to be an important disposal method for surface disposal methods (non-injection). However, it is unclear what proportions of discharge are occurring under 40 C.F.R. § 435 Subpart E and F. Discharge to a POTW (sewage) with subsequent discharge to surface water reached a peak in 1984 at 67.2 MMbbls (2.5% produced water disposition) and a low in 2017 at 13.8 MMbbls (0.43% of produced water).

For discharge of produced water from conventional oil and gas wells, operators in California are required by the sanitation districts to obtain pretreatment permits. However, pretreatment of produced water is typically minimal, consisting primarily of oil and water separators, followed by clarification and sometimes air stripping or flotation, and does not remove most chemicals associated with well stimulation operations or associated with oil and gas production. Additionally, sewage treatment plants are not typically equipped to handle produced water, potentially disrupting the treatment process and discharging salt and other contaminants into the environment (Stringfellow et al., 2015).

A search was conducted on U.S. EPA's National Pollutant Discharge Elimination System (NPDES) General Permit Web Inventory under the term "oil and gas extraction" between January 1, 1976, to February 1, 2021. This search revealed only one offshore permit issued in 2013. A search was then conducted for NPDES permits for oil and gas wastewater discharge in the California Integrated Water Quality System (CIWQS) (SWRCB, 2021c). Two permits were located for offshore discharge, one permit for stormwater discharge, and one permit for discharge of treatment groundwater from a condensate spill.

While CalGEM disposal records and reporting pursuant to SB 1281 indicate that direct discharge of produced water to surface water is ongoing, NPDES permits in CIWQS indicate little or no discharge of produced water traceable to NPDES permits. It does not appear that past and present locations of discharge of onshore produced water to surface water can be determined through CIWQS. Given these limitations it is not possible to evaluate potential impact to public health from disposal of produced water to surface water in California.

5.7. Exposure Pathway Analysis from Spills of Produced Water

Surface spills and leaks can occur at any time in the production process. Releases can result from tank ruptures, piping failures, blowouts, other equipment failures and defects, overfills, fires, vandalism, accidents, or improper operations (NYSDEC, 2011). Additionally, natural disasters (e.g., floods or earthquakes) may damage storage and disposal sites or cause them to overflow. Once released, these materials can run off into surface water bodies and/or seep into groundwater that serve as drinking water sources.

5.7.1. Environmental Impacts

Spills pose a wide variety of environmental concerns (**Figure 5.16**). For example, spills on the land surface can greatly enrich topsoil sodium and chloride content, and increase mortality rates in vegetative communities (Adams, 2011). Furthermore, chemical constituents of produced water including trace metals (Chen et al., 2017; Oetjen et al., 2018), salts, BTEX compounds (Gross et al., 2013; Shores et al., 2017), and other organic compounds (Cozzarelli et al., 2017; Drollette et al., 2015), can percolate into groundwater, providing a subsequent exposure route to co-located drinking water wells. In agricultural areas, the percolation of sodium is especially troublesome, as sodium can deplete soil nutrients (calcium, magnesium, potassium) via exchange reactions (Bäckström et al., 2004; Cates et al., 1996; Norrström & Bergstedt, 2001; Rossi, Bain, Elliott, et al., 2017; Shanley, 1994), negatively affect soil structure (Amrhein et al., 1994), reduce soil hydraulic conductivity, and salinize groundwater sources (Schoups et al., 2005; Suarez, 1989), rendering them unsuitable for irrigation (Maas, 1986).

Spills can also introduce contaminants to surface water, with a subsequent exposure route to humans through a drinking water intake or bioaccumulation in fish. For example, spills have been found to cause endocrine-disrupting activity in aquatic communities (Cozzarelli et al., 2017; Kassotis et al., 2014, 2016, 2020). Spills of produced water into surface water could also result in an accumulation of NORM (Lauer et al., 2016; Lauer & Vengosh, 2016) or trace metals (Lauer et al., 2016) in alluvial sediments, which can be mobilized by flood events or anthropogenic activities (Pizzuto, 2014; Rossi, Bain, Hillman, et al., 2017; Steding et al., 2000; Tao et al., 2005).

5.7.2. A Summary of Spill Incidents in California

Any significant or threatened release of produced water and hazardous substances must be reported to the California Office of Emergency Services (CalOES) (19 C.C.R. § 2631, 2016). The reporting threshold varies by chemical but there is no reporting threshold for produced water. Similarly, there are locational differences in reporting thresholds, with spills of oil greater than 1 barrel being the mandated threshold outside of the SJV, and 5 or 10 barrel thresholds (depending on the oil field) mandated within the SJV (San Joaquin Valley Field Rule, 1996). The CalOES maintains a database, known as the HazMat Spill Release Reporting Database, with information on the location, size, and composition of the spill; whether the spill impacted a waterway; and the cause of the spill (CalOES, 2021).

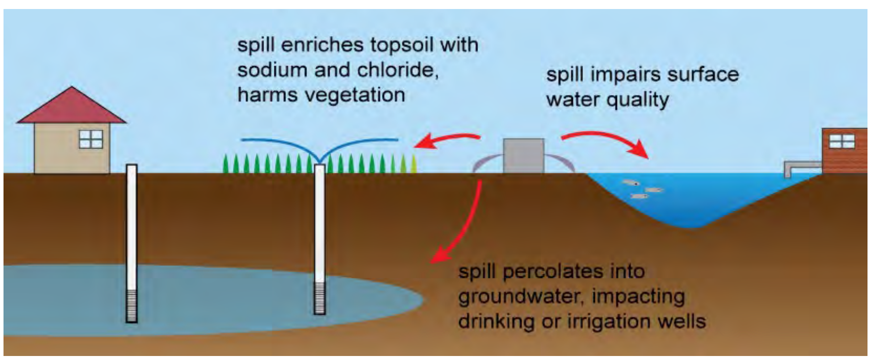

Figure 5.16. Conceptual pathways of spills.

5.7.2.1 Reported Spills in California from 2006–2020

Rossi et al. (2022) recently quantified the volume and frequency of onshore spills of crude oil and produced water in the California between 2006 and January 1, 2021. The authors retrieved every spill incident in the HazMat database containing the key words "produced water" or "crude oil," and observed a total of 2,299 incidents involving a spill of crude oil, 1,029 incidents involving a spill of produced water, and 288 incidents which involved a mixture of these two substances whose proportion was undifferentiated. During the period of 2006–2020, they noted the number of reported spill incidents involving crude oil or produced water appeared to be decreasing, with the frequency of incidents involving produced water declining relatively slower (**Figure 5.17**).

Rossi et al. (2022) observed the majority of produced water spills (65%) occurred in Kern County (**Table 5.9**), and the breakdown of crude oil spills on a per county basis follow similar trends as those observed in the produced water spills (**Table 5.9**). Only the top six counties (which represent 95% or more of spill incidents), ranked by incident counts are presented in **Table 5.9**; a complete listing of incidents by county is provided in the Appendix (Table E.6).

5.7.2.2 Comparisons to Other States

Rossi et al. (2022) also compared spill events in California to other peer-reviewed studies that examined spill incidents in other states. In general, they found trends in California crude oil and produced water spill volumes during the period of 2006–2014 were similar to those observed in North Dakota by Maloney et al. (2017), with spill events in both states marked by both chronic and catastrophic spill incidents (although the magnitude of events were more extreme in California) (**Table 5.10**).

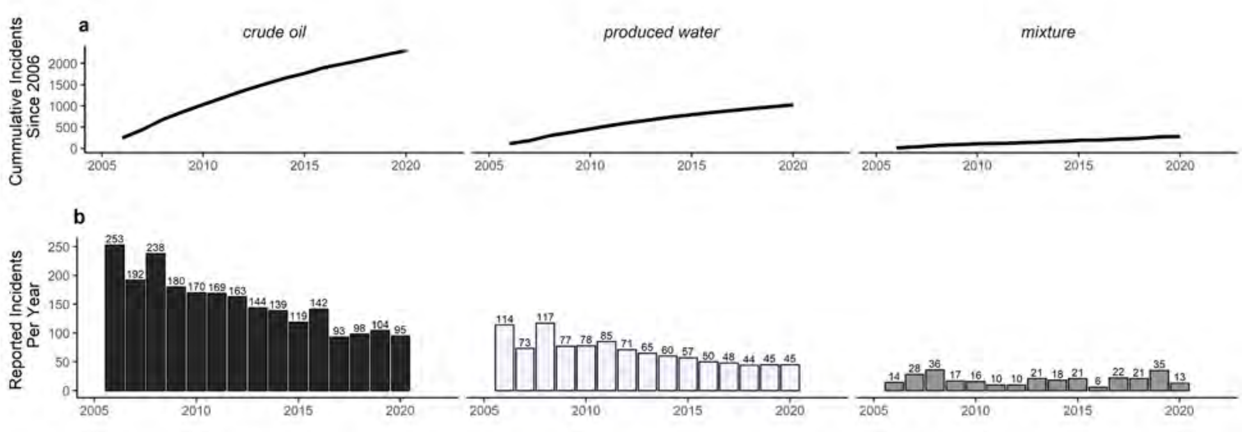

Figure 5.17. Reported number of incidents involving crude oil, produced water, or a mixture of both in the CalOES HazMat Spill Release Reporting Database (CalOES, 2021). Source: Figure 3 from Rossi et al. (2022).

Table 5.9. Breakdown of spills of crude oil, produced water, and a mixture of both by county. Source: Table 1 from Rossi et al. (2022).

Crude oil spills				Produced water spills				Mixture spills			
County	Count	%	Cum. %	County	Count	%	Cum. %	County	Count	%	Cum. %
Kern	1,165	51%	51%	Kern	665	65%	65%	Kern	126	44%	44%
Los Angeles	383	17%	67%	Los Angeles	117	11%	76%	Los Angeles	77	27%	70%
Santa Barbara	271	12%	79%	Santa Barbara	108	10%	86%	Santa Barbara	32	11%	82%
Ventura	204	9%	88%	Ventura	44	4%	91%	Ventura	18	6%	88%
Orange	63	3%	91%	Orange	28	3%	93%	Monterey	11	4%	92%
Fresno	54	2%	93%	Monterey	27	3%	96%	Fresno	10	3%	95%
San Bernardino	39	2%	95%	Fresno	22	2%	98%	Orange	8	3%	98%
Total	2299			Total	1029			Total	288		

Table 5.10. Comparison of total and average crude oil and produced water spills per year for the period of 2006–2014. Spill data for Colorado, New Mexico, North Dakota, and Pennsylvania were taken from Maloney et al. (2017). Source: Table from Rossi et al. (2022).

State	Period of analysis	Crude oil		Produced water	
		Total spills	Average yearly spills	Total spills	Average yearly spills
California	2006–2014	1,648	183	740	82
Colorado	2006–2013	48	6	29	4
New Mexico	2006–2014	121	14	138	15
North Dakota	2005–2014	2,624	263	1,538	154
Pennsylvania	2006–2014	18	2	215	24

5.7.2.3 Impacts of Spill Events on Drinking Water

Rossi et al. (2022) found that relatively few onshore incidents impacted California state waters. Specifically, they observed that 12% of crude oil, 16% of produced water, and 18% of mixture spills, respectively, have affected waterways (**Table 5.11**). These proportions were relatively higher than those reported by the U.S. EPA in an analysis of hydraulic fracturing-related spills in nine states (Arkansas, Colorado, Louisiana, New Mexico, Oklahoma, Pennsylvania, Texas, Utah, Wyoming) from 2006 to 2012 (12% and 4%, respectively) (US EPA, 2015). Rossi et al. (2022) noted that this discrepancy may have resulted due to the U.S. EPA study only considering spills associated with unconventional OGD.

Table 5.11. Counts of crude oil, produced water, and mixture spills, and documented impacts to waterways or drinking water. Source: Table 3 from Rossi et al. (2022).

	Spills Impacting Water count (%)	Spills Impacting Drinking Water count (%)
Crude oil		
Yes	273 (11.8)	0 (0)
No	2,002 (86.6)	106 (19.5)
Unknown	24 (1.0)	426 (78.3)
Produced water		
Yes	159 (15.3)	0 (0)
No	861 (83.0)	189 (78.8)
Unknown	9 (0.9)	43 (17.9)
Mixture		
Yes	52 (17.8)	0 (0)
No	229 (78.4)	38 (37.6)
Unknown	7 (2.4)	59 (58.4)

Impacts to drinking water were included in California spill reporting beginning in 2016, and Rossi et al. (2022) observed no crude oil or produced water spills were reported to have impacted drinking water (**Table 5.11**). They did note a discrepancy between crude oil and produced water spills, with 80% of reported crude oil spills indicating unknown impacts to drinking water, whereas 80% of produced water spills were reported to have not impacted drinking water (**Table 5.11**), but were unable to identify the cause.

From the data contained within spill incident reports, Rossi et al. (2022) were not able to determine what is included in the definition of “drinking water” and how impacts are determined. They postulated the requirement comes from 42 United States Code § 11004 (42 USC § 11004, 2010), but after a search of 5,000 incident reports in the HazMat database, only 28 (0.56%) were found to report impacts to drinking water, two of these incidents mentioned a well, and only one incident contained a mention of a state agency field verifying the impact to drinking water. Thus, Rossi et al. (2022) concluded impacts to drinking water were likely self-reported by the party responsible for the spill, and postulated (from the documents available on public facing websites) that there may not be a protocol for a third party (i.e., an agency with regulatory authority) to verify impact to drinking water resources following a spill event.

5.7.2.4 Inconsistencies in Spill Volume Reporting

To examine the accuracy of spill volumes in the HazMat database, Rossi et al. (2022) conducted a detailed examination of updated incident reports of produced water spills during the period of 2018–2020. They found the total volume of produced water spilled per year in 2018, 2019, and 2020 are 35%, 1,286%, and 2,750% higher, respectively, than the initially reported volumes (**Figure 5.18**). A discrepancy occurred during 2019 in Kern County (CalOES Control #19-6568), where the final volume of spilled produced water was ~1,930 times higher (~11,600 bbls) than the amount (~6 bbls) in the initial spill report (Rossi et al., 2022). Rossi et al. (2022) found no mention of a groundwater monitoring plan in the associated Notice of Violation (V19-0017), and the nearest well in the Groundwater Ambient Monitoring and Assessment (GAMA) system (Well ID L10007494132-CYM-24R2D, ~2.4 km [1.5 mi] north of the expression), was installed independently of the spill event (Kennedy Jenks, 2019).

A previous study, Stringfellow et al. (2015), noted that this reporting inconsistency increases uncertainty in understanding exposure pathways and environmental impacts from accidental releases. Additionally, linking spill incidents to well stimulation activities is difficult, as operators are not required to report whether a spill was associated with well stimulation, and incident reports do not contain an American Petroleum Institute (API) number (Stringfellow et al., 2015). A subsequent study, Caryotakis et al. (2015), attempted to link spill incidents to well activities, but was unable to due to the lack of these pieces of information.

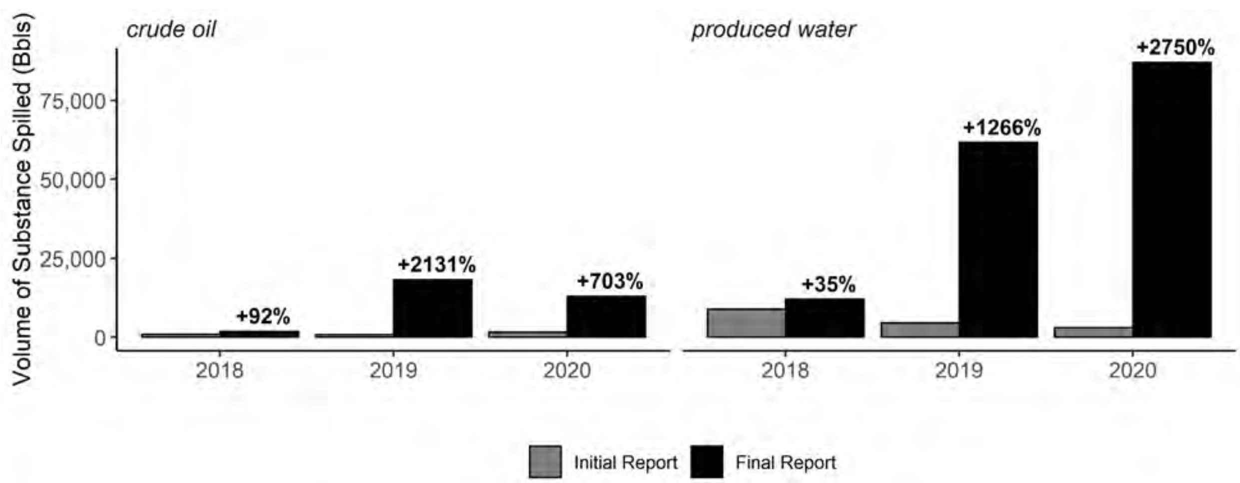

Figure 5.18. Comparison of the total reported volumes of crude oil and produced water in the initial (grey) and updated (black) CalOES spill incident reports per year. Annotations provide the percent increases of the total. Source: Figure 5 from Rossi et al. (2022).

5.7.2.5 Spill Occurrence by Volume of Material Released

Rossi et al. (2022) used the final volumes from the spill reports to generate cumulative distribution functions for each substance. They noted that while produced water spills are relatively less frequent than crude oil spills (**Figure 5.17**), typical volumes of produced water spill incidents greatly overshadow typical volumes of crude oil spill incidents (**Figure 5.19**). In particular, they observed that 50% of crude oil spills involve roughly four or less barrels of material, whereas 50% of produced water spills involve 20 or less barrels of material. This discrepancy becomes even more pronounced when considering a higher percentage of incidents, as 75% of crude oil spills are ~10 barrels or less, and 75% of produced water spills are ~100 barrels or less. Trends in the frequency of produced water spills on a per volume basis generally followed trends noted by the U.S. EPA in an multi-state analysis of hydraulic fracturing related spills during the period of 2006–2015 (US EPA, 2015).

Rossi et al. (2022) used the cumulative distribution functions for each substance to assess the adequacy of the volumetric thresholds recently released by CalGEM. Specifically, the Discussion Draft Rule that CalGEM released in October 2021 proposes instituting statewide volume thresholds for crude oil and produced water spills (0.5 and 10 barrels, respectively) occurring within 976 m (3,200 ft) of a sensitive receptor (e.g., residences, education resources, health care facilities) (CalGEM, 2021c). Rossi et al. (2022) considered crude oil spill volumes during the period 2018–2020 and noted that approximately 13% of these spills would not be reported using the proposed threshold. Likewise, approximately 38% of produced water spills were less than the proposed 10-barrel threshold. Thus, the selected thresholds appeared to introduce an inconsistency in spill reporting, which could be corrected by instituting a two-barrel reporting threshold for produced water spills (Rossi et al., 2022). Rossi et al. (2022) noted that these thresholds would only exist for areas containing sensitive receptors, which is not true for the western margins of the SJV, a relatively sparsely populated area that contains a substantial amount of oil and gas infrastructure (Rossi et al., 2022).

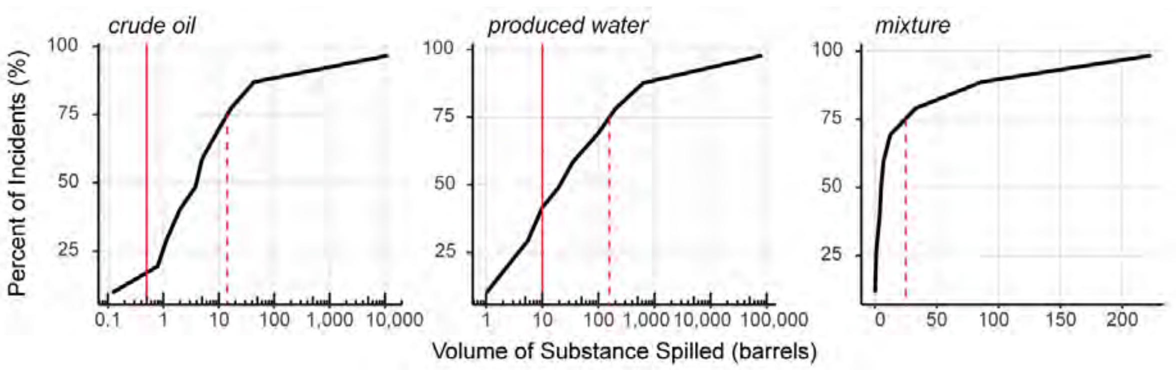

Figure 5.19. Percent of incidents in 2018–2020 involving crude oil, produced water, and mixtures of the two substances for any given volume with solid vertical annotation lines indicating proposed reporting thresholds for spilled materials (CalGEM, 2021c), and dashed vertical annotation lines indicating the volume that 75% of spill incidents are less than. Data used to generate these cumulative distributions were taken from the updated spill reports. Source: Figure 6 from Rossi et al. (2022).

5.7.2.6 Summary of Shortcomings of the Spill Database

In summary, Rossi et al. (2022) found it difficult to thoroughly analyze spill incidents in California using the current publicly facing database. Their findings were in line with a previous analysis, Caryotakis et al. (2015), who described the HazMat spill database as "incomplete, disorganized, and difficult to analyze effectively." Extra sources (e.g., CalGEM notice of violations) must be located to link extra information such as the type (conventional or unconventional) of operations (Caryotakis et al., 2015; Stringfellow et al., 2015). Furthermore, accurate release volumes of spill incidents must be manually retrieved from updated incident reports on a case-by-case nature, and comprehensive geospatial analyses of spill incidents are impossible due to the lack of exact location data reporting in spill reports (Rossi et al., 2022). Likewise, currently it is nearly impossible for outside parties to determine the environmental impacts associated with a particular spill event; Rossi et al. (2022) found incident reports to contain no mention of monitoring activities following releases. Due to these limitations, it is not possible to evaluate the potential impact of crude oil and produced water spills on public health.

5.8. Exposure Pathways from Use of Produced Water for Irrigation

In the United States, the practice of reusing untreated (from a water quality point of view) oil field produced water for irrigation is limited to select oil fields in the Central Valley region of California (Mahoney et al., 2021). This practice is currently expanding; the Kern-Tulare Water District has constructed an additional reservoir — the Guzman Reservoir completed in early 2021 (Google Earth Pro, 2021) — to increase capacity to receive produced water from oil field operators. Although the use of produced water for irrigation represents an additional exposure pathway, a Finding of No Significant Impact (FONSI) report by the U.S. Bureau of Reclamation determined that the new Kern-Tulare Water District reservoir project would have a beneficial impact on air quality from the reduction of sulfur dioxide and nitrogen oxides released to the air due to reduced emissions from existing activities such as produced water injection and the pumping and distribution of water for irrigation (USBR, 2017).

The SJV occupies the southern two-thirds of the Central Valley in California and is separated into the San Joaquin Basin to the north and the Tulare Basin to the south. The SJV is one of the most explored hydrocarbon-containing basins in the United States, with over 100,000 oil and gas wells (Hosford Scheirer, 2013) and one of the most agriculturally productive regions in the world (Hanak et al., 2017) — supplying over one-third of vegetables and two-thirds of the fruits and nuts consumed in the United States (CDFA, 2021; Xiao et al., 2017). Agriculture in the SJV is dependent on surface water from winter/spring snowpack melt, with excess demand met by groundwater withdrawal (Famiglietti et al., 2011), especially during drought years (CDWR, 2021; Faunt et al., 2009; Hanak et al., 2017).

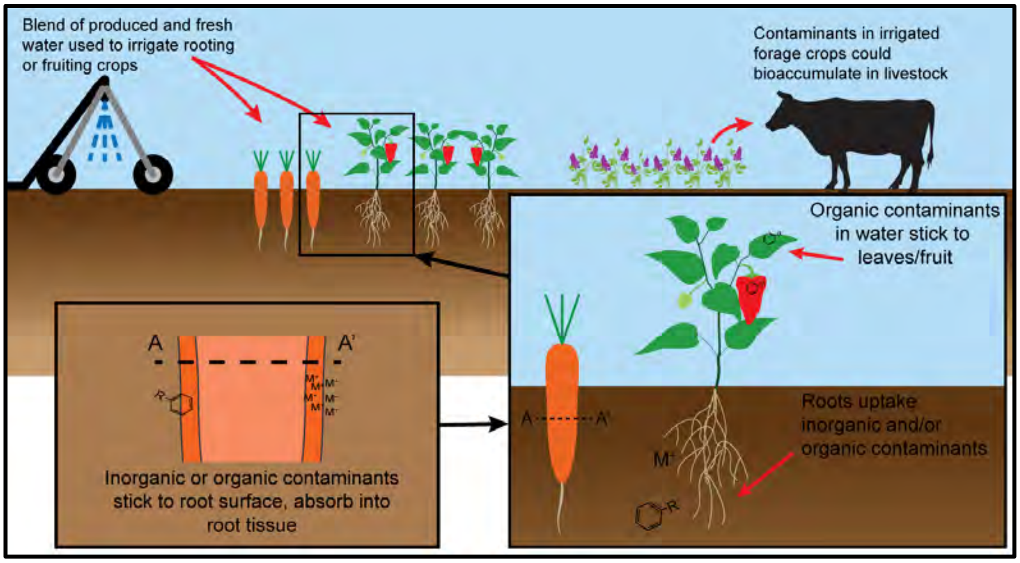

Figure 5.20. Conceptual contamination and exposure pathways of the use of produced water for irrigation.

If produced water is used for irrigation, exposure pathways include bioaccumulation of compounds in food for direct or indirect (via livestock) human consumption or via drinking water from groundwater contamination (**Figure 5.20**). A portion of the produced water in the SJV is combined with surface and groundwater and used for the irrigation of crops for human consumption. However, the use of produced water from stimulated wells for irrigation has been met with more concern, as a technical review of well stimulation in California concluded that produced water from stimulated wells could contain hazardous chemicals and chemical byproducts (CCST, 2015). The report included recommendations that agencies of jurisdiction should clarify that produced water from hydraulically fractured wells cannot be reused for purposes such as irrigation, which could negatively impact the environment, human health, wildlife, and vegetation (CCST, 2015).. This ban should continue until or unless testing for hydraulic fracturing chemicals and breakdown products shows non-hazardous concentrations, or required water treatment reduces concentrations to non-hazardous levels (CCST, 2015).. At present. produced water used for irrigation does not come from wells that have been hydraulically fractured.

In January 2016, the CVRWQCB convened a food safety expert panel to examine the safety of using produced water for irrigation of food crops for direct or indirect human consumption. The water board released a White Paper summarizing findings and recommendations of the panel in January 2021 (Mahoney et al., 2021). The panel recommended that the water board (1) discontinue crop sampling given other anthropogenic sources of chemicals and numerous uncertainties and limitations of analytical methods; (2) continue and periodically update water quality monitoring requirements as new analytical methods for regulatory use emerge; (3) evaluate the spatial and temporal variability of produced water used for irrigation; (4) consider the use of non-targeted analytical methods and bioanalytical assays to better characterize produced water used for irrigation; (5) continue disclosure of chemical additives currently used for oil and gas production; (6) continue evaluation of new additives; (7) consider requiring the disclosure of mass data for additives; (8) develop a list of additives considered as low hazard for potential use by oil and gas field operators; (9) continue compiling chemical and toxicological information on additives as new information emerges; (10) consider findings of the panel when approving Waste Discharge Requirements for use of produced water for irrigation; (11) sponsor laboratory and controlled field studies to better understand the fate and transport of chemicals in produced water during irrigation; and (12) sponsor soil studies to better understand the impact of produced water on soil properties, fertility, microbiology, and accumulation of heavy metals and persistent organic compounds. The published White Paper from the panel was divided into three main tasks: (1) characterize the chemicals (either added or naturally occurring) in produced water, and assess their hazards; (2) perform a literature review to see the hazards from ingesting these chemicals, examine plant uptake of these chemicals, and determine the persistence of these chemicals in agricultural ecosystems; and (3) perform an experimental manipulation of irrigation of crops with and without produced water. In general, the panel concluded that no immediate threat to either human health or crop safety resulted from reusing produced water for irrigation. The panel issued general recommendations that the current produced water reuse program should continue with the sole modification of discontinuing crop sampling, potential hazards from chemical additives should be further constrained, and data gaps should be closed by conducting environmental studies and employing emerging water quality methods.

5.9. Summary

The generation of produced water (a by-product of many oil and gas related activities) has been increasing in California since 1994. Produced water can contain a wide range of chemical constituents including residual petroleum hydrocarbons, chemical additives, geogenic compounds, and degradation byproducts of chemical transformations. Although some of these inorganic (e.g., arsenic, radium) and organic (e.g., benzene, toluene) compounds are known toxicants, produced waters are not classified as hazardous waste under the Resource Conservation and Recovery Act, and analysis requirements for produced waters discharged to percolation ponds in the CVRWQCB jurisdiction have only relatively recently been strengthened. For example, starting in 2015 the CVRWQCB required a relatively comprehensive analysis of produced waters disposed in unlined percolation ponds, but other regional water quality control boards do not appear to have adopted similarly stringent regulatory programs.

Produced water is most often disposed of via subsurface injection, which is commonly used for enhanced oil recovery. Produced waters disposed of in this manner can potentially impact domestic or municipal water wells via a variety of pathways, leading to groundwater contamination (**Figure 5.4**). From publicly accessible documents, it is not clear if any of these impacts have occurred as a result of subsurface injection in California. A U.S. EPA-funded audit, completed in 2011, identified deficiencies (e.g., an inconsistent definition of protected water, lax enforcement of appropriate maximum allowable surface injection pressures) in California’s UIC program. The audit, in conjunction with the passage of Senate Bill 83 in 2015, led to a strengthened oversight of the UIC program. Currently a panel comprised of a diverse group of experts is evaluating the regulatory performance and administration of the UIC Program and will make recommendations of improvements. At present, approximately 261,000 Californians live within 1 km (3,281 ft) of a water disposal well (**Figure 5.5**).

Another common disposal method of produced water is discharge into lined or unlined earthen structures known as produced water ponds. Like other disposal methods, the disposal of water in these ponds could potentially impact humans via a number of exposure pathways (**Figure 5.7**). Disposal ponds are primarily located in the southern SJV; however, ponds are also located in Southern California. Currently no state agency maintains a comprehensive list of all ponds in California (DiGiulio et al., 2021). Disposal of produced water into unlined produced water ponds has been ongoing in California since the early 20th century, but this practice has drastically decreased since 2014. Likewise, disposal of produced water into lined ponds has decreased since the early 1990s. An analysis of chemical data collected from produced water ponds in the SWRCB's Geotracker database highlights that detected concentrations of constituents of concern in produced water ponds commonly exceed CA MCLs (**Figure 5.9**). Likewise, detected concentrations of electrical conductivity, chloride, and boron in 75% or more samples exceed the Tulare Basin effluent limits, often in areas that overlie groundwater resources. Despite this clear threat to groundwater resources, groundwater monitoring at unlined produced water pond facilities is relatively sparse. Airborne emissions of organic compounds from ponds also likely pose another public health concern, but these emissions are relatively under-characterized in the peer reviewed literature. Roughly 545,000 (~1 in 75) Californians live within 1 km (3,281 ft) of an active, inactive, or historical produced water pond, with about 168,000 of those residents located within 1 km (3,281 ft) of an active pond. The lack of spatially explicit domestic well locations, coupled with a lack of knowledge pertaining to the transport distances of airborne contaminants, precludes determining what proportion of these populations are at risk.

The discharge of produced water to surface water poses the potential for humans to come into contact with a variety of chemical constituents (e.g., radionuclides, trace metals, organic compounds) via multiple exposure pathways (**Figure 5.15**). Conceptually, produced water discharges to surface waters can occur directly or indirectly via POTWs. While indirect discharges via POTWs are allowed (with the exception of produced waters from unconventional wells), pretreatment standards do not exist for waters discharged in this way. In California, produced water undergoes minimal pretreatment prior to discharge to POTWs; consequently, most chemicals associated with well stimulation operations remain. In California, this practice peaked in 1984 (67.2 MMbbls or 2.5% produced water disposition) and decreased until 2017 (13.8 MMbbls or 0.43% of produced water disposition). In general, regulatory limitations (i.e., 40 C.F.R. §§ 435.30-435.34, 2021) have effectively prohibited direct discharges to surface waters except for certain uses. For example, one such use applicable to California is discharging produced water (provided it meets Effluent Limitation Guidelines) for wildlife, livestock watering, or other agricultural purposes. Direct discharges to surface water in California peaked in 1988 (497.2 MMbbls or 18.9% produced water disposition) and have generally declined until 2017 (58.9 MMbbls or 1.8% of produced water disposition). While surface discharges of produced water appear to continue to be an important surface disposal method in California (second only to discharges into unlined ponds), it is unclear exactly what use these discharges fall under. Furthermore, searches of both the NPDES General Permit Web Inventory and CIWQS returned scant information relating to contemporary or historical produced water discharges. Thus, potential impacts to public health from disposal of produced water to surface water in California were not evaluated.

Spills of produced water pose multiple concerns for human, vegetative, and biotic receptors through both surface and subsurface pathways (**Figure 5.16**). Significant releases of produced water must be reported to CalOES; however, there is no reporting threshold for produced water. Between January 1, 2006, and January 1, 2021, a total of 1,029 spill incidents involving produced water have been reported to CalOES, with the majority (51%) of these events occurring in Kern County. None of these incidents have been reported to impact drinking water, but from publicly available data it is not clear how impacts to drinking water are determined. Furthermore, it is unclear if groundwater monitoring is conducted following large spill events. While the frequency of spills of produced water appears to be decreasing since 2006, comparisons to studies examining the frequency of produced water spills in other states suggest produced water spills may occur relatively more frequently in California. Although CalOES maintains a publicly available database of spill events, retrieving data pertaining to spill incidents is time intensive, and generally lacks precise location data. Moreover, updated spill volumes are not rapidly retrievable, and during the years 2018–2020, volumes of produced water spilled were underreported anywhere from 35% to 2,750%. These data limitations make it nearly impossible to evaluate potential impacts of produced water spills on public health in California.

The SJV has the unique distinction of being both one of the most agriculturally productive regions in the world, and one of the most explored hydrocarbon-containing basins in the United States. Significant water demand, projected to be exacerbated by both population growth and climatic shifts, has led to the blending of produced water with surface and groundwater to be used for agricultural irrigation in select areas of the Tulare Basin. This practice is currently expanding, with a new reservoir currently (at the time of writing this report) being constructed within the Kern-Tulare Water District to expand the storage capacity of blended water (i.e., blends of fresh and produced water). The possible existence of hazardous chemicals in produced water used for irrigation has garnered concerns from an expert panel reviewing well stimulation in California, and led to the recommendation that produced waters from hydraulically fractured wells be disallowed for irrigation purposes. To determine the safety of this practice, the CVRWQCB convened a separate food safety expert panel, who released a White Paper in January 2021. This white paper contains a list of 12 findings and recommendations and concludes no immediate threat to either human health or crop safety resulted from reusing produced water for irrigation. In general, the panel recommended that the current produced water reuse program should continue with the sole modification of discontinuing crop sampling, that potential hazards from chemical additives should be further constrained, and data gaps should be closed by conducting environmental studies and employing emerging water quality methods. Similarly, after reviewing the Kern-Tulare Water District reservoir project, the U.S. Bureau of Reclamation issued a FONSI. As such, although the reuse of produced water for crop irrigation does pose a potential contaminant pathway, the likelihood of this occurring seems relatively small compared to other pathways such as accidental releases of produced water, or the discharge of produced water into unlined pits.

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Appendix E

E.1. Produced Water Dataset Compilation

Produced water datasets were cleaned and standardized for compilation. All results that were reported as zero, a non-detection qualifier (e.g., "ND"), below a detection/reporting limit (e.g., <0.05), or negative were not considered in compiled summary statistics. Results reported as a range (e.g., >100 mg/L) were removed to allow for consolidation. If no measurement value was provided for a given analysis or if the value was "NA", it was assumed that the analysis was not done. Charge balance values were included in some databases; however, data points were not removed because large charge imbalances were often due to a missing major ion analyte(s). Duplicate samples across USGS datasets were removed when both API and sample date information were available. Summary statistics, including minimum, maximum, and percentiles, for common water quality parameters and other measured constituents were then calculated. Due to inconsistent data reporting and limited availability of detection/reporting limits, well API, and sample date information across all datasets, aggregation of produced water data by well API was not possible. As such, samples taken from the same well, but on different dates were treated as separate samples for compiled summary statistics.

Table E.1. Compiled Produced Water Quality for OGD in California. Only constituents with at least one detection are listed here.

Constituents	Detections (%)	Min	Med	Max	Percentile				
					5th	25th	75th	95th	Units
General Water Quality									
Alkalinity	877 (100)	73	2,900	5,600	916	2,500	3,600	4,400	mg/L
Alkalinity as $CaCO_3$	1,490 (100)	0.34	2,800	5,800	255	2,000	3,300	4,100	mg/L
Alkalinity, total	143 (100)	100	855	6,680	256	524	1,800	2,870	mg/L
Hardness	307 (99.4)	0.2	150	8,820	2.1	5.8	506	2,970	mg/L
Specific conductance	356 (100)	29	35,000	190,476	3,790	16,150	42,000	60,210	mMhos/cm
Electrical conductivity	186 (100)	0.29	55.7	52,200	5.44	27.1	2250	8350	mMhos/cm
Total dissolved solids	4,070 (100)	28	26,000	890,000	3,250	18,000	31,000	47,000	mg/L
Salinity	279 (100)	9	3,690	97,200	50	129	20,450	30,110	mg/L
Total organic carbon	22 (95.7)	18	225	2,054	25.7	110	798	1,167	mg/L
Dissolved organic carbon	63 (100)	6.2	130	5,000	9.04	42.5	214	2,010	mg/L
Oxidation reduction potential	244 (100)	-219	192	424	-61.1	130	353	402	mV
Resistivity	862 (100)	0.08	0.37	32.4	0.19	0.25	1.02	4.09	ohm-m
Turbidity	160 (100)	0.7	100	1,000	15.8	78.9	333	973	NTU
Specific Gravity	1,317 (100)	0.99	1.02	1.22	1.002	1.01	1.024	1.04	unitless
pH	3,967 (100)	1.0	7.6	11.8	6.7	7.3	7.8	8.3	pH units

Constituents	Detections (%)	Min	Med	Max	Percentile				
					5th	25th	75th	95th	Units
Major Ions									
Bicarbonate	1,702 (99.2)	2.0	1,154	12,809	163	582	2,270	4,550	mg/L
Carbonate	329 (27.5)	1	51.6	2,250	3.76	20.4	138	447	mg/L
Bromide	2,606 (97.6)	0.19	100	16,000	28	73	130	166	mg/L
Chloride	4,211 (99.9)	1.0	14,000	360,000	408	8,670	17,000	24,980	mg/L
Sulfate	3,023 (73.8)	0.1	38	15,250	3.77	24	87.2	475	mg/L
Calcium	4,333 (99.9)	0.1	190	190,000	22	128	350	2,110	mg/L
Magnesium	4,306 (99.5)	0.08	120	10,000	6.8	67	166	457	mg/L
Potassium	3,082 (99.8)	1.2	190	52,000	33	140	300	1,400	mg/L
Sodium	4,102 (100)	4.48	8,700	120,000	870	6,200	10,400	13,000	mg/L
Inorganics									
Aluminum	55 (44.3)	0.01	0.63	2,530	0.025	0.2	2.5	518	mg/L
Antimony	253 (9.8)	10	160	17,000	30	70	260	478	µg/L
Arsenic	194 (7.6)	10	190	4,600	40	90	298	996	µg/L
Barium	3,316 (96.6)	0.01	7.7	26,300	1.0	5.1	11	55	mg/L
Beryllium	76 (2.9)	10	10	4,130	10	10	20	170	µg/L
Boron	3,289 (99.3)	0.02	92	158,000	4.2	62	105	150	mg/L
Cadmium	52 (2.0)	10	30	420	10	10	40	143	µg/L
Cesium	42 (82.3)	20	195	900	20.5	60	400	567	µg/L
Chromium	643 (25.1)	10	40	9,400	10	30	70	200	µg/L
Chromium VI	68 (3.1)	10	10	610	10	10	20	93	µg/L
Cobalt	102 (3.9)	10	30	8,510	10	10	50	344	µg/L
Copper	884 (33.6)	10	40	184,000	10	30	80	619	µg/L
Fluoride	337 (12.8)	0.03	1.4	53	0.17	0.5	3.8	23.2	mg/L
Iodine	451 (95.5)	0.1	35	294	2.2	15.6	61	136	mg/L
Iron	2,693 (91.8)	0.01	12	48,100	0.4	3.5	37	130	mg/L
Lead	240 (9.3)	10	80	30,000	10	20	170	1,200	µg/L
Lithium	2,759 (98.9)	0.004	5.8	17,500	0.99	4.15	8.3	18.1	mg/L
Manganese	2,579 (95.0)	10	480	85,7000	110	250	920	2,800	µg/L
Mercury	7 (0.3)	10	30	980	10	10	160	755	µg/L
Molybdenum	343 (13.2)	10	40	48,500	10	20	70	270	µg/L
Nickel	550 (21.5)	10	50	22,000	10	22.5	100	396	µg/L
Selenium	429 (16.7)	10	280	15,000	54	130	530	1,900	µg/L
Silver	33 (1.3)	10	50	260	10	30	60	162	µg/L
Strontium	2,886 (99.8)	0.01	11.2	190,000	2.80	7.2	16	126	mg/L

Constituents	Detections (%)	Min	Med	Max	Percentile 5th	25th	75th	95th	Units
Thallium	27 (1.0)	10	90	6,400	13	25	365	3,010	µg/L
Vanadium	91 (3.6)	10	70	24,000	10	45	135	1,350	µg/L
Zinc	1,017 (38.8)	10	110	243,000	30	70	250	1,920	µg/L
Silica	744 (98.5)	0.18	60	2,200	14	36	90.2	177	mg/L
Hydrogen sulfide	444 (17.1)	0.01	0.22	1,111	0.06	0.1	1	6.19	mg/L
Radionuclides/Isotopes									
Gross alpha	1,916 (81.8)	0.05	66.1	2,589	7.33	32.9	109	238	pCi/L
Gross beta	2,283 (97.6)	0.14	144	41,000	29.2	88.2	227	1,380	pCi/L
Radium-224	21 (100)	2.3	12	130	4	8	25	47.7	pCi/L
Radium-226	2,326 (98.6)	0.03	24.7	917	5.21	15.7	33.2	65.5	pCi/L
Radium-228	258 (94.8)	0.08	13	515	1.48	5.59	28.6	60.8	pCi/L
Radon	513 (71.2)	0.3	98	3,917	6	40.2	193	556	pCi/L
Radon-222	1,148 (71.5)	0.52	106.3	250,690	10.2	49	213	1,560	pCi/L
Uranium	8 (22.2)	0.28	1.84	7.03	0.44	1.25	4.37	6.84	µg/L
Nutrients									
Ammonia	158 (99.3)	1.28	27.5	2,300	7.08	17	41.0	75.5	mg/L
Ammonia (as N)	30 (100)	1.4	106	460	5.38	10.9	161	428	mg/L
Ammonium	272 (92.8)	3	138	2,560	12.2	73.8	201	377	mg/L
Nitrate	214 (8.9)	0.1	12	800	0.6	1.59	24.8	170	mg/L
Nitrate (as N)	14 (13.0)	0.1	0.89	14.4	0.1	0.17	6.05	11.5	mg/L
Nitrite	646 (28.0)	0.04	0.09	10	0.04	0.05	0.27	0.97	mg/L
Nitrite (as N)	4 (5.4)	1.99	3.78	5.8	2.01	2.11	5.49	5.74	mg/L
Nitrite, nitrate	1 (0.6)	220	220	220	220	220	220	220	mg/L
Nitrite, nitrate (as N)	37 (22.8)	0.02	0.07	8.02	0.02	0.03	0.11	2.53	mg/L
Phosphate	6 (54.5)	0.2	1.15	20.5	0.2	0.23	2.04	15.9	mg/L
Phosphate, Ortho	3 (6.8)	0.31	2.4	16.8	0.52	1.36	9.6	15.4	mg/L
Organics									
Total carbohydrates	2,041 (97.4)	1.2	97	11,000	21	53	190	560	mg/L
Guar gum	155 (89.5)	30	150	3500	36.7	79	255	1,490	mg/L
Benzene	2,293 (98.0)	10	710	25,000	80	300	1,400	3,600	µg/L
Toluene	2,307 (98.5)	10	1,900	61,000	170	885	3,000	4,970	µg/L
Ethylbenzene	2,277 (97.2)	10	250	5,300	40	140	360	670	µg/L
m-Xylenes	68 (100)	210	770	6,000	300	488	1,200	2,030	µg/L
o-Xylene	2,129 (98.3)	10	420	5,700	70	230	640	1,200	µg/L
Total Xylenes	2,307 (98.5)	10	1,200	19,000	140	570	2,000	3,800	µg/L

Constituents	Detections (%)	Min	Med	Max	Percentile 5th	25th	75th	95th	Units
Naphthalene	9 (75)	10	30	3,900	14	30	250	2,980	µg/L
1,2,4-Trimethylbenzene	4 (80)	250	300	3,400	255	273	1,090	2,940	µg/L
1,3,5-Trimethylbenzene	2 (40)	90	535	980	135	313	758	936	µg/L
Acetate	54 (98.1)	0.8	34	4,865	3.13	11.5	414	1,730	mg/L
Acetic acid	9 (60)	2.2	37	910	2.28	2.7	340	850	mg/L
Fuel oil No.2	6 (100)	12	28	46	14.3	21.3	40.8	45.3	mg/L
Gasoline	6 (100)	4.4	5.85	16	4.6	5.2	10.5	15	mg/L
Hydrotreated light petroleum distillate	6 (100)	4.8	34.5	150	8.6	22.8	52.3	127	mg/L
Total petroleum hydrocarbons	2 (100)	79	1,290	2,500	200	680	1,890	2,380	mg/L
Methane	2,336 (98.5)	0.006	0.74	280	0.04	0.27	1.40	3.5	mg/L
Propane	31 (93.9)	0.2	372	7,080	0.25	42.4	1,070	4,820	µg/L
p-Bromofluorobenzene	1 (100)	10	10	10	10	10	10	10	µg/L
p-Cymene	2 (40)	30	205	380	47.5	118	293	363	µg/L
n-Butylbenzene	2 (40)	20	165	310	34.5	92.5	238	296	µg/L
n-Propylbenzene	2 (40)	60	485	910	103	273	698	868	µg/L
2,2-Dibromo-3-nitrilopropionamide	52 (32.7)	5	15	20	5	10	20	20	mg/L
Gases									
Argon	21 (100)	0.012	0.029	1.92	0.012	0.015	0.153	1.89	mol %
C6+ Hydrocarbons	20 (95.2)	0.002	0.64	3.08	0.0019	0.059	1.16	1.9	mol %
Hexane, normal	3 (75)	0.03	0.25	0.29	0.052	0.14	0.27	0.29	mol %
Isobutane	18 (85.7)	0.0021	0.23	3.12	0.018	0.104	0.35	2.51	mol %
Isopentane	18 (85.7)	0.0003	0.061	1.96	0.002	0.028	0.56	1.93	mol %
n-Butane	32 (84.2)	0.0007	0.162	6.31	0.0011	0.029	0.85	4.32	mol %
Carbon dioxide	127 (96.9)	0.29	28.4	700	3.86	21.9	35.2	86.9	mg/L
Carbon monoxide	1 (4.76)	0.18	0.18	0.18	0.18	0.18	0.18	0.18	mol %
Helium	9 (69.2)	0.0058	0.0077	0.013	0.0058	0.0065	0.0095	0.012	mol %
Nitrogen	21 (100)	0.31	1.04	94.6	0.32	0.53	8.43	93.3	mol %
Oxygen	4 (100)	0.097	0.255	2.49	0.11	0.16	0.87	2.17	mol %

Abbreviations: mg/L - millgrams per liter; mMhos/cm - millimhos per centimeter; mol % - mole percent; mV – millivoit; NTU - nephelometric turbidity unit; ohm-m - ohm-metre; pCi/L - picocuries per liter; µg/L - micrograms per liter

E.2. Locations of Water Disposal Wells

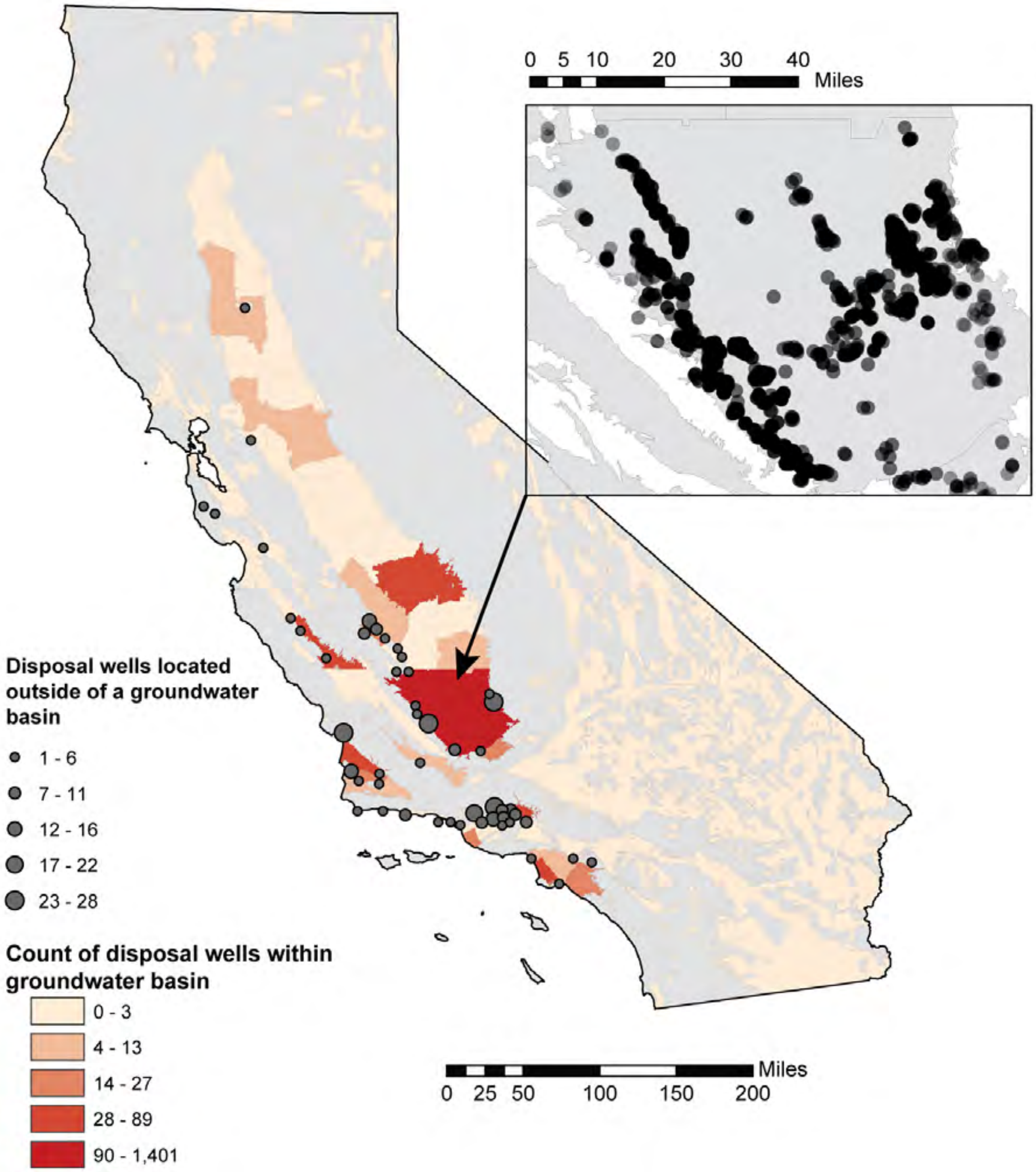

Figure E.1. Locations of all water disposal wells contained within the CalGEM "All Oil and Gas Wells" dataset (CalGEM, 2021d). Source: Groundwater basins from CADWR (2020).

E.3. Characterization of the Chemistry of Produced Water Ponds

Table E.2. Summary of produced water ponds aqueous data as measured by the California Air Resources Board. Source: Schmidt and Card (2020).

					Percentile				
Constituents	**No. of Detections**	**Min**	**Med**	**Max**	**5th**	**25th**	**75th**	**95th**	**Units**
Oil & Grease	94	1.4	13.5	660,000	2.95	7.13	28	537	mg/L
BTEX									
Benzene	86	0.1	6	1,650	0.18	0.5	70.3	838	µg/L
Ethylbenzene	84	0.11	6.45	1,600	0.22	0.95	34.3	688	µg/L
Toluene	86	0.1	3.35	1,900	0.14	0.6	25.3	550	µg/L
Total Xylenes	86	0.39	9.9	2,200	0.51	2.2	60.3	979	µg/L
p- & m-Xylenes	85	0.29	5.7	1,400	0.4	1.3	40	629	µg/L
o-Xylene	90	0.09	3.6	790	0.12	0.9	20.8	349	µg/L
Other Species									
Bromobenzene	0	--	--	--	--	--	--	--	µg/L
Bromochloromethane	0	--	--	--	--	--	--	--	µg/L
Bromodichloromethane	0	--	--	--	--	--	--	--	µg/L
Bromoform	0	--	--	--	--	--	--	--	µg/L
Bromomethane	0	--	--	--	--	--	--	--	µg/L
n-Butylbenzene	25	0.11	0.63	250	0.14	0.44	2.8	54.7	µg/L
sec-Butylbenzene	37	0.16	0.53	190	0.17	0.23	1.7	18.6	µg/L
tert-Butylbenzene	3	0.24	0.25	3.6	0.24	0.25	1.93	3.27	µg/L
Carbon tetrachloride	0	--	--	--	--	--	--	--	µg/L
Chlorobenzene	2	0.19	0.22	0.24	0.19	0.2	0.23	0.24	µg/L
Chloroethane	0	--	--	--	--	--	--	--	µg/L
Chloroform	0	--	--	--	--	--	--	--	µg/L
Chloromethane	0	--	--	--	--	--	--	--	µg/L
2-Chlorotoluene	0	--	--	--	--	--	--	--	µg/L
4-Chlorotoluene	0	--	--	--	--	--	--	--	µg/L
Dibromochloromethane	0	--	--	--	--	--	--	--	µg/L
1,2-Dibromo-3-chloropropane	0	--	--	--	--	--	--	--	µg/L
1,2-Dibromoethane	0	--	--	--	--	--	--	--	µg/L
Dibromomethane	0	--	--	--	--	--	--	--	µg/L
1,2-Dichlorobenzene	0	--	--	--	--	--	--	--	µg/L
1,3-Dichlorobenzene	0	--	--	--	--	--	--	--	µg/L
Dichlorodifluoromethane	0	--	--	--	--	--	--	--	µg/L
1,1-Dichloroethane	0	--	--	--	--	--	--	--	µg/L
1,2-Dichloroethane	0	--	--	--	--	--	--	--	µg/L
1,1-Dichloroethene	0	--	--	--	--	--	--	--	µg/L
cis-1,2-Dichloroethene	0	--	--	--	--	--	--	--	µg/L
trans-1,2-Dichloroethene	0	--	--	--	--	--	--	--	µg/L
1,2-Dichloropropane	0	--	--	--	--	--	--	--	µg/L

					Percentile				
Constituents	No. of Detections	Min	Med	Max	5th	25th	75th	95th	Units
1,3-Dichloropropane	0	--	--	--	--	--	--	--	µg/L
2,2-Dichloropropane	0	--	--	--	--	--	--	--	µg/L
1,1-Dichloropropene	0	--	--	--	--	--	--	--	µg/L
cis-1,3-Dichloropropene	0	--	--	--	--	--	--	--	µg/L
trans-1,3-Dichloropropene	0	--	--	--	--	--	--	--	µg/L
Hexachlorobutadiene	0	--	--	--	--	--	--	--	µg/L
Isopropylbenzene	60	0.14	1.33	240	0.15	0.46	2.71	14.2	µg/L
p-Isopropyltoluene	45	0.15	0.81	200	0.16	0.33	3.6	50.1	µg/L
Methylene chloride	0	--	--	--	--	--	--	--	µg/L
Methyl t-butyl ether	1	95.5	95.5	95.5	95.5	95.5	95.5	95.5	µg/L
Naphthalene	64	0.46	8.35	280	0.92	1.95	18	73.6	µg/L
n-Propylbenzene	62	0.11	1.15	500	0.14	0.34	2.68	16	µg/L
Styrene	0	--	--	--	--	--	--	--	µg/L
1,1,1,2-Tetrachloroethane	0	--	--	--	--	--	--	--	µg/L
1,1,2,2-Tetrachloroethane	0	--	--	--	--	--	--	--	µg/L
Tetrachloroethene	3	0.13	0.17	0.2	0.13	0.15	0.19	0.2	µg/L
1,2,3-Trichlorobenzene	0	--	--	--	--	--	--	--	µg/L
1,2,4-Trichlorobenzene	0	--	--	--	--	--	--	--	µg/L
1,1,1-Trichloroethane	0	--	--	--	--	--	--	--	µg/L
1,1,2-Trichloroethane	0	--	--	--	--	--	--	--	µg/L
Trichloroethene	1	0.9	0.9	0.9	0.9	0.9	0.9	0.9	µg/L
Trichlorofluoromethane	0	--	--	--	--	--	--	--	µg/L
1,2,3-Trichloropropane	1	51	51	51	51	51	51	51	µg/L
1,1,2-Trichloro-1,2,2-trifluoroethane	0	--	--	--	--	--	--	--	µg/L
1,2,4-Trimethylbenzene	82	0.13	3.65	1,200	0.18	0.88	13.8	91	µg/L
1,3,5-Trimethylbenzene	69	0.12	1.1	300	0.15	0.39	3.35	19	µg/L
Vinyl chloride	0	--	--	--	--	--	--	--	µg/L

Table E.3. Summary of produced water ponds air emissions data as measured by the California Air Resources Board. Source: Schmidt and Card (2020).

					Percentile				
Constituents	**No. of Detections**	**Min**	**Med**	**Max**	**5th**	**25th**	**75th**	**95th**	**Units**
Total Non-Methane Hydrocarbons	90	65.6	5,770	47,300,000	178	1,530	37,800	288,000	C6 $\mu g/m^3$
Total Non-Methane Hydrocarbons	90	73	6,420	52,700,000	198	1,700	42,100	321,000	C1 $\mu g/m^3$
TO-14 BTEX									
Benzene	86	1.4	47.3	158,000	2.38	6.77	514	14,600	$\mu g/m^3$
Ethylbenzene	78	1.75	49.2	666,000	2.45	10.3	245	3,960	$\mu g/m^3$
Toluene	83	1.39	46.8	587,000	2.79	11.5	736	27,300	$\mu g/m^3$
m,p-Xylene	81	1.32	69.6	1,130,000	2.64	15.2	553	8,570	$\mu g/m^3$
o-Xylene	76	1.89	63.3	205,000	3.87	14.1	476	5,420	$\mu g/m^3$
TO-15 BTEX									
Benzene	88	1.47	56.7	125,000	2.94	10.1	342	11,800	$\mu g/m^3$
Ethylbenzene	57	1.5	39.2	303,000	4.27	11.1	318	2,510	$\mu g/m^3$
Toluene	75	0.92	55.7	574,000	2.93	9.94	571	19,800	$\mu g/m^3$
m,p-Xylenes	62	1.1	84.2	579,000	2.98	16.4	602	9,120	$\mu g/m^3$
o-Xylene	55	1.21	86.4	286,000	3.84	15.3	398	4,960	$\mu g/m^3$
Total Xylene	71	0	86.3	865,000	0	10.3	739	13,200	$\mu g/m^3$
Total BTEX	95	0	104	1,870,000	1.85	17.1	1,150	42,500	$\mu g/m^3$
Carbon Dioxide	40	0.01	0.05	0.41	0.02	0.02	0.13	0.32	%
Methane	88	0.47	11	1,350	1.18	2.67	117	487	ppmv
TO-14									
1,2,3-Trimethylbenzene	51	1.87	43.9	203,000	5.34	13.6	177	4,050	$\mu g/m^3$
1,2,4-Trimethylbenzene	80	2.17	38.4	164,000	2.86	9.92	249	4,830	$\mu g/m^3$
1,3,5-Trimethylbenzene	77	2.23	32.6	239,000	3.18	8.69	202	3,000	$\mu g/m^3$
1,3-Diethylbenzene	57	2.79	43.9	590,000	5.79	15.9	276	8,690	$\mu g/m^3$
1,4-Diethylbenzene	58	2.31	59.5	88,100	3.91	21.4	235	6,150	$\mu g/m^3$
1-Butene	3	2.18	9.27	32.7	2.89	5.73	21	30.4	$\mu g/m^3$
1-Pentene	4	8.94	11.2	1320	9.16	10	339	1,120	$\mu g/m^3$
2,2,4-Trimethylpentane	48	1.99	52.4	1,460,000	2.46	6.84	229	3,230	$\mu g/m^3$
2,2-Dimethylbutane	2	23.9	27.8	31.8	24.3	25.8	29.8	31.4	$\mu g/m^3$
2,3,4-Trimethylpentane	47	1.79	32.3	883,000	2.06	6.89	255	2,580	$\mu g/m^3$
2,3-Dimethylbutane	2	2.15	2.97	3.79	2.23	2.56	3.38	3.71	$\mu g/m^3$
2,3-Dimethylhexane	30	2.19	81.5	132,000	4.21	18.1	410	3,170	$\mu g/m^3$
2,3-Dimethylpentane	35	2.23	42	393,000	3.03	8.99	212	15,200	$\mu g/m^3$
2,4-Dimethylhexane	45	1.77	19.9	576,000	3.39	7.62	147	1,600	$\mu g/m^3$
2,4-Dimethylpentane	54	1.54	53.2	1,586,188	2.43	8.19	463	3,940	$\mu g/m^3$
2,5-Dimethylhexane	39	2.92	62.1	468,000	4.1	14.5	198	9,640	$\mu g/m^3$
2-Ethyltoluene	47	1.66	52.1	531,000	4.36	20.8	195	18,500	$\mu g/m^3$

Constituents	No. of Detections	Min	Med	Max	Percentile 5th	25th	75th	95th	Units
2-Methylheptane	41	5.37	82.1	1,520,000	13.3	34.6	259	1,990	µg/m^3
2-Methylpentane	50	2.36	65.6	1,040,000	2.85	13.1	447	2,900	µg/m^3
3-Ethyltoluene	46	3.36	31.3	297,000	4.7	16.4	173	1,840	µg/m^3
3-Methylheptane	40	5.57	67.4	614,000	7.08	34.1	135	17,600	µg/m^3
3-Methylhexane	66	1.4	42.2	1,100,000	3.53	11	319	1,050	µg/m^3
3-Methylpentane	49	1.99	23.9	816,000	2.71	7.17	190	6,410	µg/m^3
4-Ethyltoluene	64	1.49	40.9	427,000	2.7	13.7	359	3,400	µg/m^3
Acetylene	5	12.1	34.6	57.3	13.2	17.3	41.4	54.1	µg/m^3
a-Pinene	10	3.24	26.6	10,900	4.73	9.07	75.8	6,120	µg/m^3
b-Pinene	12	3.14	40.6	11,700	12.1	31.5	195	5,480	µg/m^3
c-2-Butene	0	--	--	--	--	--	--	--	µg/m^3
c-2-Pentene	5	2.13	11.6	81.7	2.13	2.13	22.9	70	µg/m^3
Cyclohexane	31	2	39.6	79,000	2.08	4.53	346	10,000	µg/m^3
Cyclopentane	1	114	114	114	114	114	114	114	µg/m^3
d-Limonene	13	2.43	22.8	14,300	3.73	12.4	168	6,920	µg/m^3
Dodecane	77	1.9	37.5	78,500	3.24	9.15	162	2,220	µg/m^3
Ethane	92	1.82	44.5	25,100	4.18	11.6	552	4,900	µg/m^3
Ethene	40	1.89	17.7	647	2.26	4.47	31.7	317	µg/m^3
i-Butane	50	2.14	19.4	31,000	2.83	7.46	155	2,450	µg/m^3
i-Pentane	63	1.54	43	405,000	2.06	6.7	237	5,150	µg/m^3
i-Propylbenzene	56	1.37	35.4	233,000	2.77	8.39	245	1,070	µg/m^3
Isoprene	1	123	123	123	123	123	123	123	µg/m^3
Methylcyclohexane	49	4.16	76.7	1,930,000	4.7	9.63	720	4,330	µg/m^3
Methylcyclopentane	15	1.46	8.07	1,590	2.17	6.04	25.3	511	µg/m^3
n-Butane	75	1.62	14.4	159,000	2.28	6.31	74.6	3,110	µg/m^3
n-Butylbenzene	27	6.43	79.2	15,200	8.11	32.5	370	2,530	µg/m^3
n-Decane	74	1.88	52.5	826,000	4.2	14.1	221	4,280	µg/m^3
n-Heptane	63	1.39	28.7	2,260,000	2.22	5.9	118	2,060	µg/m^3
n-Hexane	79	1.46	38.9	1,920,000	1.85	4.97	134	7,990	µg/m^3
n-Nonane	75	1.76	31.4	1,600,000	3.14	11.7	164	3,390	µg/m^3
n-Octane	79	1.98	30.1	1,910,000	2.64	7.16	130	1,410	µg/m^3
n-Pentane	85	1.81	21.1	790,000	2.75	6.17	157	11,300	µg/m^3
n-propylbenzene	54	2.16	28.5	188,000	3.51	12.6	278	1,340	µg/m^3
Propane	84	3.02	42.4	10,500	3.55	9.86	299	4,640	µg/m^3
Propene	6	3.9	29.1	37.1	9.7	27.5	34	36.7	µg/m^3
Styrene	34	3.63	26	1140	4.17	11.1	113	1,010	µg/m^3
t-2-Butene	1	17.2	17.2	17.2	17.2	17.2	17.2	17.2	µg/m^3
t-2-Pentene	7	3.84	21.5	198	5.91	11	39.1	154	µg/m^3
Undecane	78	1.58	46.1	374,000	2.41	9.38	201	5,900	µg/m^3

Constituents	No. of Detections	Min	Med	Max	Percentile 5th	25th	75th	95th	Units
TO-15									
1,1,1-Trichloroethane	0	--	--	--	--	--	--	--	µg/m³
1,1,2,2-Tetrachloroethane	1	2.56	2.56	2.56	2.56	2.56	2.56	2.56	µg/m³
1,1,2-Trichloroethane	2	870	4340	7,820	1,220	2,610	6,080	7470	µg/m³
1,1-Dichloroethane	0	--	--	--	--	--	--	--	µg/m³
1,1-Dichloroethene	4	6.14	16.9	53.5	6.14	6.15	34.2	49.7	µg/m³
1,2,4-Trichlorobenzene	0	--	--	--	--	--	--	--	µg/m³
1,2,4-Trimethylbenzene	50	1.22	28.1	210,000	3.71	12.9	327	9,800	µg/m³
1,2-Dibromoethane	2	5	14.9	24.9	5.99	9.96	19.9	23.9	µg/m³
1,2-Dichlorobenzene	4	1.44	4.81	9.84	1.78	3.16	6.87	9.25	µg/m³
1,2-Dichloroethane	0	--	--	--	--	--	--	--	µg/m³
1,2-Dichloropropane	0	--	--	--	--	--	--	--	µg/m³
1,3,5-Trimethylbenzene	31	1.46	23.3	55,800	2.56	7.03	178	7,090	µg/m³
1,3-Butadiene	0	--	--	--	--	--	--	--	µg/m³
1,3-Dichlorobenzene	0	--	--	--	--	--	--	--	µg/m³
1,4 Dioxane	1	38.4	38.4	38.4	38.4	38.4	38.4	38.4	µg/m³
1,4-Dichlorobenzene	0	--	--	--	--	--	--	--	µg/m³
2-Butanone	53	2.69	367	34,200	6.56	49.6	3230	10,800	µg/m³
2-Hexanone	18	2.56	39.7	743	6.44	13.5	143	359	µg/m³
2-propanol	25	7.38	96	1,900	8.92	32.8	346	1,140	µg/m³
4-Ethyltoluene	33	2.33	22	214,000	4.42	8.45	428	23,700	µg/m³
4-Methyl-2-pentanone	16	6.45	25.4	500	7.08	10.7	38.7	357	µg/m³
Acetone	77	4.74	435	49,100	10.9	90.4	2,960	15,800	µg/m³
Benzyl chloride	2	2.25	7.88	13.5	2.81	5.07	10.7	12.9	µg/m³
Bromochloromethane	0	--	--	--	--	--	--	--	µg/m³
Bromodichloromethane	0	--	--	--	--	--	--	--	µg/m³
Bromoform	0	--	--	--	--	--	--	--	µg/m³
Bromomethane	6	3	20.9	26.9	4.89	12.2	25.8	26.7	µg/m³
Carbon disulfide	29	4.91	58.5	1,000	10.3	22.7	190	523	µg/m³
Carbon tetrachloride	0	--	--	--	--	--	--	--	µg/m³
Chlorobenzene	1	71.3	71.3	71.3	71.3	71.3	71.3	71.3	µg/m³
Chloroethane	0	--	--	--	--	--	--	--	µg/m³
Chloroform	0	--	--	--	--	--	--	--	µg/m³
Chloromethane	7	0.83	18.9	77.3	1.24	8.01	35.9	69.9	µg/m³
cis-1,2-Dichloroethene	0	--	--	--	--	--	--	--	µg/m³
cis-1,3-Dichloropropene	0	--	--	--	--	--	--	--	µg/m³
Cyclohexane	6	1.33	841	124,000	111	449	1,700	93,300	µg/m³
Dibromochloromethane	0	--	--	--	--	--	--	--	µg/m³
Dichlorodifluoromethane	0	--	--	--	--	--	--	--	µg/m³
Dichloromethane	0	--	--	--	--	--	--	--	µg/m³
Ethanol	8	3.76	30.9	986	4.94	8.34	90.6	717	µg/m³

					Percentile				
Constituents	**No. of Detections**	**Min**	**Med**	**Max**	**5th**	**25th**	**75th**	**95th**	**Units**
Ethyl acetate	0	--	--	--	--	--	--	--	µg/m^3
Freon 113	0	--	--	--	--	--	--	--	µg/m^3
Freon 114	0	--	--	--	--	--	--	--	µg/m^3
Hexachlorobutadiene	0	--	--	--	--	--	--	--	µg/m^3
Methyl methacrylate	2	4.12	4.16	4.19	4.12	4.14	4.17	4.19	µg/m^3
Methyl tert butyl ether	0	--	--	--	--	--	--	--	µg/m^3
Naphthalene	36	0.83	11	2,410	1.02	3.62	26.2	836	µg/m^3
n-Heptane	16	23.6	221	2,040,000	31.7	53.2	871	1,030,000	µg/m^3
Styrene	4	5.74	68.1	3,120	5.79	5.99	877	2,670	µg/m^3
Tetrachloroethene	3	3.74	64.9	234	9.85	34.3	149	217	µg/m^3
Tetrahydrofuran	0	--	--	--	--	--	--	--	µg/m^3
trans-1,2-Dichloroethene	0	--	--	--	--	--	--	--	µg/m^3
trans-1,3-Dichloropropene	2	9.31	78.9	148	16.3	44.1	114	142	µg/m^3
Trichloroethene	0	--	--	--	--	--	--	--	µg/m^3
Trichlorofluoromethane	0	--	--	--	--	--	--	--	µg/m^3
Vinyl acetate	3	18.7	394	2,640	56.2	206	1,510	2,410	µg/m^3
Vinyl chloride	0	--	--	--	--	--	--	--	µg/m^3

E.4. Counts of Produced Water Ponds by Location and Status

Table E.4. Oil and gas fields having produced water ponds from DiGiulio et al. (2021).

Field Name	Field Code	County	Irrigation Pond	Unlined Active Pond	Unlined Inactive Pond	Unlined Closed Pond	Lined Active Pond	Lined Inactive Pond	Lined Closed Pond	Lined or Unlined Inactive Pond	Lined or Unlined Active Pond	Lined or Unlined Closed	Unidentified	Total Ponds	GW Subbasin
Northeastern Area of Kern Subbasin															
Jasmin	328	Kern	0	7	10	2	0	0	3	0	0	0	0	22	Kern
Kern Bluff	336	Kern	0	0	3	0	0	0	0	3	0	0	0	6	Kern
Kern Front	338	Kern	1	14	35	0	0	0	0	6	1	0	0	57	Kern
Kern River	340	Kern	0	0	13	2	0	0	0	0	0	2	0	17	Kern
Mount Poso	488	Kern	9	6	15	1	0	0	0	4	2	0	0	37	Kern
Poso Creek	566	Kern	19	0	17	6	0	2	2	3	0	1	0	50	Kern
Round Mountain	628	Kern	0	0	17	0	0	3	0	1	0	0	0	21	Kern
Area Summary			**29**	**27**	**110**	**11**	**0**	**5**	**5**	**17**	**3**	**3**	**0**	**210**	
Central Eastern Area of Kern Subbasin															
Ant Hills	018	Kern	0	0	1	0	0	3	0	0	0	0	0	4	Kern
Edison	222	Kern	0	6	43	7	3	1	0	0	1	30	0	91	Kern
Edison, Northeast	224	Kern	0	0	0	0	0	0	0	0	1	0	0	1	Kern
Fruitvale	256	Kern	0	0	11	2	0	0	0	1	0	0	0	14	Kern
Mountain View	490	Kern	0	0	25	60	0	2	4	0	0	4	0	95	Kern
Rosedale Ranch	626	Kern	0	0	1	0	0	0	0	0	0	0	0	1	Kern
Area Summary			**0**	**6**	**81**	**69**	**3**	**6**	**4**	**1**	**2**	**34**	**0**	**206**	
Central Area of the Kern Subbasin															
Bellevue	044	Kern	0	0	4	0	0	0	0	0	0	0	0	4	Kern
Canal	104	Kern	0	0	0	0	0	4	0	0	0	0	0	4	Kern
Canfield Ranch	106	Kern	0	0	0	0	0	1	0	0	0	5	0	6	Kern
Greeley		Kern	0	0	0	0	0	0	0	0	0	0	0	0	Kern
Rio Bravo	602	Kern	0	0	0	0	0	3	0	0	0	0	0	3	Kern
Semitropic	690	Kern	0	0	1	11	0	0	0	0	0	1	0	13	Kern
Strand	787	Kern	0	0	8	2	0	0	0	0	0	0	0	10	Kern
Stockdale	786	Kern	0	0	2	0	0	0	0	0	0	0	0	2	Kern
Ten Section	766	Kern	0	0	0	0	0	0	0	0	0	2	0	2	Kern
Wasco	822	Kern	0	0	0	1	0	0	0	0	0	0	0	1	Kern
Area Summary		**Kern**	**0**	**0**	**15**	**14**	**0**	**8**	**0**	**0**	**0**	**8**	**0**	**45**	
West Central Area of the Kern Subbasin															
Coles Levee North	156	Kern	0	0	7	0	0	0	0	0	0	0	0	7	Kern
Coles Levee South	158	Kern	0	0	7	0	0	1	0	0	0	0	0	8	Kern
Area Summary			**0**	**0**	**14**	**0**	**0**	**1**	**0**	**0**	**0**	**0**	**0**	**15**	
South Central Area of the Kern Subbasin															
Comanche Point	160	Kern	0	0	4	0	0	0	0	0	0	0	0	4	Kern
Landslide	375	Kern	0	0	1	0	0	0	0	0	0	0	0	1	
San Emido Nose		Kern	0	0	0	0	0	0	0	0	0	0	0	0	Kern

Field Name	Field Code	County	Irrigation Pond	Unlined Active Pond	Unlined Inactive Pond	Unlined Closed Pond	Lined Active Pond	Lined Inactive Pond	Lined Closed Pond	Lined or Unlined Inactive Pond	Lined or Unlined Active Pond	Lined or Unlined Closed	Unidentified	Total Ponds	GW Subbasin
Tejon	752	Kern	0	0	5	6	0	4	3	0	0	0	0	18	Kern
Tejon Hills	756	Kern	0	0	3	4	0	0	0	0	0	0	0	7	Kern
Tejon North	758	Kern	0	0	1	0	0	0	0	0	0	0	0	1	Kern
Wheeler Ridge	832	Kern	0	0	0	0	0	0	0	0	0	1	0	1	Kern
Valpredo	808	Kern	0	0	0	0	0	0	0	2	0	0	0	2	Kern
Yowlumne		Kern	0	0	0	0	0	0	0	0	0	0	0	0	Kern
Area Summary			**0**	**0**	**14**	**10**	**0**	**4**	**3**	**2**	**0**	**1**	**0**	**34**	
Western Area of the Kern Subbasin															
Antelope Hills	020	Kern	0	18	4	0	0	0	0	0	0	0	0	22	Kern
Antelope Hills North	022	Kern	0	0	4	0	0	0	0	0	0	0	0	4	Kern
Asphalto	032	Kern	0	19	6	1	0	0	0	1	1	0	0	28	Kern
Belgian Anticline	042	Kern	0	85	1	0	0	0	0	1	0	0	0	87	Kern
Blackwells Corner	060	Kern	0	0	0	6	0	0	0	0	0	1	0	7	Kern
Carneros Creek	117	Kern	0	8	2	0	0	0	0	0	0	0	0	10	Kern
Chico-Martinez	140	Kern	0	3	2	0	0	0	0	0	0	0	0	5	Kern
Cymric	190	Kern	0	22	92	0	0	0	0	4	2	3	0	123	Kern
Devils Den	204	Kern	0	4	8	5	0	1	0	0	0	0	0	18	Kern
Elk Hills	228	Kern	0	1	30	0	0	0	0	0	0	0	0	31	Kern
Lost Hills	432	Kern	0	4	9	8	3	0	0	3	0	0	0	27	Kern
Lost Hills Northwest	434	Kern	0	0	0	0	0	0	0	3	0	0	0	3	Kern
McDonald Anticline	450	Kern	0	3	3	19	0	2	0	0	0	0	0	27	Kern
McKittrick	454	Kern	0	4	6	0	0	0	0	2	0	0	0	12	Kern
Belridge North	050	Kern	0	3	5	25	4	0	0	1	0	0	80	118	Kern
Belridge South	052	Kern	0	2	14	198	17	2	0	0	0	5	0	238	Kern
Temblor Ranch	762	Kern	0	0	0	0	0	0	0	2	0	0	0	2	Kern
Welcome Valley	826	Kern	0	0	1	1	0	0	0	0	0	0	0	2	Kern
Area Summary			**0**	**176**	**187**	**263**	**24**	**5**	**0**	**17**	**3**	**9**	**80**	**764**	
Southwestern Area of the Kern Subbasin															
Buena Vista	080	Kern	0	0	4	9	0	0	0	0	0	0	0	13	Kern
Midway-Sunset	102	Kern	0	219	53	7	11	4	0	19	5	5	15	338	Kern
Area Summary			**0**	**219**	**57**	**16**	**11**	**4**	**0**	**19**	**5**	**5**	**15**	**351**	
Tule Subbasin															
Deer Creek	194	Tulare	0	23	6	3	0	0	0	0	1	3	0	36	Tule
Deer Creek North	196	Tulare	0	0	3	0	0	0	0	0	0	0	0	3	Tule
Area Summary			**0**	**23**	**9**	**3**	**0**	**0**	**0**	**0**	**1**	**3**	**0**	**39**	
Pleasant Valley and Westside Subbasins															
Coalinga	150	Fresno	0	22	22	44	2	1	2	2	7	4	0	106	Pleasant Valley/ Westside

Field Name	Field Code	County	Irrigation Pond	Unlined Active Pond	Unlined Inactive Pond	Unlined Closed Pond	Lined Active Pond	Lined Inactive Pond	Lined Closed Pond	Lined or Unlined Inactive Pond	Lined or Unlined Active Pond	Lined or Unlined Closed	Unidentified	Total Ponds	GW Subbasin
Coalinga, East Extension	152	Fresno	0	0	7	5	0	0	0	0	0	4	0	16	Westside
Guijarral Hills	288	Fresno	0	0	2	3	0	0	0	1	0	0	0	6	Pleasant Valley
Jacalitos	326	Fresno	0	0	0	3	0	0	0	0	0	0	0	3	Pleasant Valley
Area Summary			**0**	**22**	**31**	**55**	**2**	**1**	**2**	**3**	**7**	**8**	**0**	**131**	
Kettleman Plain Subbasin															
Pyramid Hills	578	Kings	0	11	9	14	1	0	0	0	6	0	0	41	Kettleman Plain
Helm	300	Fresno	0	0	1	1	0	1	2	0	0	0	0	5	Kings
Raisin City	584	Fresno	0	0	1	0	2	1	26	1	0	5	0	36	Kings
Riverdale	613	Fresno	0	0	0	1	0	0	1	0	0	0	0	2	Kings
Area Summary			0	11	11	16	3	2	29	1	6	5	0	84	
Total Pond Summary			**29**	**484**	**529**	**457**	**43**	**36**	**43**	**60**	**27**	**76**	**95**	**1879**	

E.5. Populations Living in Proximity to Produced Water Ponds

Table E.5. Total populations living within buffer distance of produced water disposal features.

Buffer Distance	Population Living Within Distance of a Pond	Population Living Within Distance of an Active Pond	Population Living Within Distance of a Disposal Well	Population Living Within Distance of Water Infrastructure
500 ft (152 m)	12,902	2,724	4,346	7,058
1,000 ft (305 m)	61,517	13,274	20,695	33,253
1,500 ft (457 m)	138,650	32,545	50,493	80,099
2,000 ft (610 m)	235,002	63,069	93,664	149,654
2,500 ft (762 m)	343,479	98,616	150,377	236,921
3,281 ft (1 km)	544,644	167,641	261,320	402,463
5,280 ft (1.61 km)	1,226,568	467,156	681,756	1,023,614

E.6. County Level Spill Counts

Table E.6. Breakdown of spills of crude oil, produced water, and a mixture of both by county. Source: Table S1 from Rossi et al. (2022).

County	Crude oil spills		Produced water spills		Mixture spills	
	Count	%	Count	%	Count	%
Alameda	1	0.04	1	0.1		
Colusa					1	0.3
Contra Costa	21	0.9			3	1.0
Fresno	54	2.3	22	2.1	10	3.5
Kern	1,165	50.7	665	64.6	126	43.8
Kings	12	0.5	3	0.3	2	0.7
Los Angeles	383	16.7	117	11.4	77	26.7
Madera	1	0.04				
Merced	1	0.04				
Monterey	34	1.5	27	2.6	11	3.8
Orange	63	2.7	28	2.7	8	2.8
Placer	10	0.4				
Riverside	1	0.04	1	0.10		
San Benito	1	0.04				
San Bernardino	39	1.7				
San Diego	1	0.04				
San Francisco	1	0.04				
San Joaquin	8	0.3	1	0.1		
San Luis Obispo	18	0.8	4	0.4		
Santa Barbara	271	11.8	108	10.5	32	11.1
Shasta	1	0.04				
Solano	5	0.2	2	0.2		
Stanislaus	1	0.04				
Sutter			5	0.5		
Tulare	3	0.1	1	0.1		
Ventura	204	8.9	44	4.3	18	6.3
Total	2,299		1,029		2,88	

CHAPTER SIX

Legacy Oil and Gas Infrastructure: Implications for Public Health

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6.0. Abstract

In this chapter, the potential hazards, exposure pathways, impacts to human health, and data gaps related to abandoned and idled wells and other associated legacy oil and gas infrastructure in the state of California are examined. Data from the California Geologic Energy Management Division (CalGEM) provided the basis to examine the current number of indexed idle and abandoned wells and overall trends in the number of producing wells from the period of 2019–2021. According to CalGEM's records, there are approximately 41,100 idle wells and 128,900 abandoned wells in the state; however, multiple studies suggest that the number of abandoned wells may be significantly greater than those indexed by CalGEM. Current trends in the number of producing wells indicates a year-over-year decrease in the number of producing wells from 2018–2021. The number of idle and abandoned wells is expected to increase as more wells reach their end of life or become no longer economically viable.

Few studies have examined emissions of hazardous air pollutants from idle or abandoned wells; however, it is likely that anytime there exists a pathway for gas to escape to the atmosphere, there is also the potential for co-occurring volatile organic compounds (VOCs) and other toxic air contaminants (TACs) to be released. A review of the epidemiological literature revealed insufficient information to draw conclusions about the potential health risks associated with proximity to inactive wells, abandoned wells, and other legacy oil and gas infrastructure.

Hazards associated with the in-place abandonment of pipelines include the release of residual oil and gas compounds, treatment chemicals, naturally occurring radioactive materials (NORM), technologically enhanced naturally occurring radioactive materials (TENORM), polychlorinated biphenyls (PCBs), and asbestos. A number of states have developed or are developing regulations on the disposal of TENORM associated with oil and gas development — California is not one of them. Despite existing regulations for pipeline abandonment, leaks from improperly abandoned pipelines in California have resulted in occupational exposures and threats to nearby communities.

Significant knowledge gaps surrounding the number and location of idle-deserted and abandoned wells and abandoned legacy pipelines remain. Studies of emissions from idle, inactive, and abandoned wells in the state remain limited. The extent of PCB contamination, TENORM/NORM buildup, and presence of asbestos in pipeline coatings in legacy infrastructure in California is unknown.

6.1. Introduction

California has a long history of drilling for oil and gas. The first commercial oil well in California was drilled in 1876, just 17 years after the discovery of oil in Pennsylvania. This well was located in Pico Canyon near Santa Clarita, and initially produced 25 barrels of oil per day, increasing to 150 barrels per day after drilling deeper (AOGHS, 2020). However, as is typical for most wells, this well's production slowed with time, and then the well ceased its production and eventually required abandonment.

In 2022, more than 146 years later, 58,000 wells are actively producing across California. An additional 41,100 wells are currently idle, often because they do not produce enough oil or gas to be economically viable, and 128,900 wells have gone through their lifecycle and have been plugged and abandoned **(Table 6.1)**. This chapter addresses the potential hazards, impacts to human health, research findings, and data gaps related to these abandoned and idle wells and other associated legacy oil and gas infrastructure.

6.2. Idle, Idle-deserted, and Abandoned Wells and Associated Infrastructure in California

6.2.1. Clarification of terminology for these well types

States and countries use different nomenclature systems to refer to oil and gas wells at various stages of their lifecycles. Here, we briefly explain the terms used in California and in this report as defined in the California Public Resource Codes and by the California Geologic Energy Management Division (CalGEM) to provide clarity in the subsequent sections of this report.

An active well is a well that has been drilled and completed and has been used for oil or gas production, enhanced oil recovery, reservoir pressure management, or injection of waste or other fluids within the past 24 months. “Idle well” means any well that for a period of 24 consecutive months has not either produced oil or natural gas, produced water to be used in production stimulation, or been used for enhanced oil recovery, reservoir pressure management, or injection (Cal. Pub. Res. Code § 3008, 2018). Unlike abandoned wells, idle wells can be returned to production and injection. An idle well continues to be an idle well until it has been properly abandoned in accordance with California Public Resources Code (P.R.C.) § 3208 (2017) or it has been shown to the Division's satisfaction that, since the well became an idle well, the well has for a continuous six-month period either maintained production of oil or natural gas, maintained production of water used in production stimulation, or been used for enhanced oil recovery, reservoir pressure management, or injection (P.R.C. § 3008, 2018). An “idle-deserted well” is defined as “an oil and gas well determined by the supervisor to be deserted under [Public Resources Code] [s]ection 3237 and for which there is no operator responsible for its plugging and abandonment under [Public Resources Code] [s]ection 3237” (P.R.C. § 3251, subd. (e).

There are factors such as loss of economic viability that will result in an operator's decision to plug and abandon a well at its own cost according to California’s plugging and abandonment standards. The state is responsible for the cost of plugging idle-deserted wells because there is no operator responsible for their plugging and abandonment under P.R.C. § 3237 Abandonment of a well is permanent; wells which are abandoned do not start producing again. Current plugging and abandonment procedures focus on preventing pollutants from reaching the surface or entering subsurface groundwater. The current abandonment standards have remained relatively unchanged since 1978 and are further described in Section 6.3.4 (CCST, 2018). Wells plugged prior to these modern plugging requirements were regulated under much less stringent standards. Prior to regulations from the Department of Conservation, some legacy abandoned wells were not plugged at all. Because many of these wells could be undocumented by CalGEM in their current system, there is a concern that they are not included in total wells counts.

The total number of abandoned wells in the United States is estimated at more than 3 million and increasing (US EPA, 2022a). In the United States, more than three-quarters of the abandoned wells are oil wells with the remaining wells gas wells. As can be seen in **Figure 6.1**, most of the abandoned wells are unplugged but not necessarily leaking.

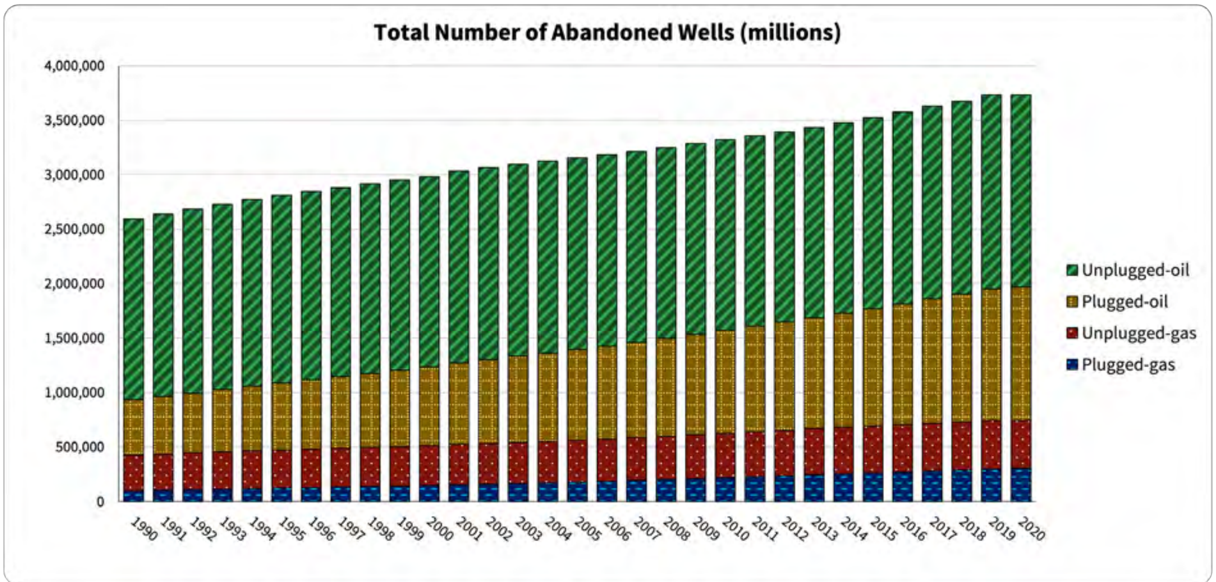

Figure 6.1. Total number of abandoned wells (millions) in the United States. Source: US EPA (2022a).

6.2.2. Number and Location of Abandoned Wells in California

Well status and location data were obtained from the CalGEM "All Wells" dataset (CalGEM, 2022a); numbers of wells of each category are shown in **Table 6.1**. As of September 2022, there were approximately 129,000 plugged and abandoned wells in California. Abandoned wells are located throughout the state but are at greatest density in the Central Valley, Los Angeles Basin, and the Sacramento regions (**Figure 6.2**). In California, nonassociated gas (gas produced without oil) is typically produced in the northern part of the state, while associated gas (gas produced as byproduct of oil production) is most common in Southern California.

The California Council on Science and Technology (CCST) estimated that approximately 41,000 abandoned wells were plugged before modern requirements went into effect in 1978, increasing the risk that some abandoned wells may need to be "re-abandoned" in the future (CCST, 2018). Inadequate abandonment practices in the early 20th century included using trash, telephone poles, logs, and rocks to block up wells (California State Lands Commission, 2017). Ongoing projects are working to identify and properly plug these legacy abandoned wells throughout the state (e.g., the Coastal Hazards and Legacy Oil and Gas Well Removal and Remediation Program).

The actual number of abandoned wells in California may be significantly higher than reported in the CalGEM dataset. There is a long history of drilling for oil in California, going back to the late 1800s; contemporaneous records of drilling and abandoning are not available for many of these legacy wells (California State Lands Commission, 2020). A study by Lebel et al. (2020) suggested that the number of abandoned wells in California may be underreported by 17% based on a comparison of CalGEM data with historical U.S. Geological Survey (USGS) maps from the 1940s. Another study by Williams et al. (2021) suggested that abandoned oil and gas wells in California total approximately 200,000.

Table 6.1. Number of wells in California according to well status from the CalGEM “All Wells” Dataset as of September 8, 2022. In addition to the well types already discussed, “New” means a well has been recently permitted and is in the process of being drilled and “Canceled” means that the well permit was canceled and no well was drilled.

Well Status	Count
Plugged and Abandoned	128,864
Idle	41,069
Active	58,011
Canceled	9,286
New	3,722
Plugged Only	186
Unknown*	37

***Well status not known; mostly older wells dated pre-1976.

6.2.3. Number and Location of Idle and Idle-deserted Wells in California

Approximately 41,100 wells are listed as idle in the CalGEM database. Long-term idle wells were not differentiated from other idle wells in the database; however, according to the most recent Idle Well Program report, 17,560 idle wells met the definition of long-term idle at some point in 2019 (CalGEM, 2021). The locations of active, idle, and plugged wells are shown in **Figure 6.2**. Idle wells are generally located in the same regions as active wells. Because idle production wells must be non-producing for a 24-month period, there is an inherent lag between when production stops and a well is categorized as idle. There is also a period between when an idle well starts producing and when it is considered an active well, however, this is only a six-month period. Active wells are not all producing wells and can be injectors, underground gas storage, or observation wells as well. Given the issues noted in this paragraph, the true number of wells that are not actively producing at any given time may not be reliably estimated in CalGEM’s “All Wells” dataset.

An idle-deserted well refers to an oil and gas well determined by the supervisor to be deserted under P.R.C. § 3237 and for which there is no operator responsible for its plugging and abandonment under P.R.C. § 3237. Although CalGEM maintains a list of idle wells, they have not historically monitored operator solvency (CCST, 2018). CalGEM is currently in the process of identifying idle-deserted wells under its Well Abandonment Program. In order to consider a well idle-deserted, CalGEM must (1) determine if a well is deserted by the operator, and (2) perform a financial solvency test to determine if any there are any solvent entities responsible for plugging the well (CalGEM, 2021). In the Idle Well Program report covering the reporting period of January 1, 2019, to December 31, 2019, CalGEM identified 24 idle-deserted wells and an additional 3,265 wells that are deserted or potentially deserted (CalGEM, 2021). The process of determining if a well (or group of wells) is idle-deserted, or if there is a solvent responsible entity, takes approximately four to six months (CalGEM, 2021).

A study by CCST (2018) identified idle-deserted (referred by CCST as orphaned) and likely idle-deserted wells using the following criteria:

- **Likely idle-deserted wells**: wells with no production or injection in past five years and belong to operators with no California production in past five years.
- **Wells at high risk of becoming idle-deserted wells**: wells with no production or injection in past five years and the operator is small and operates primarily idle and marginal wells.
- **Other idle and economically marginal wells**: wells producing <5 barrels of oil equivalent per day

CCST estimated 2,565 wells in California are likely idle-deserted wells and another 2,975 are at high risk of becoming idle-deserted wells in the near future. A further 69,425 economically marginal or idle wells are at risk of becoming idle-deserted wells in the future due to declining production or if acquired by financially weak operators. The locations of these wells are shown in **Figure 6.3**.

Based on 2019 data provided to the Interstate Oil and Gas Compact Commission, there are an estimated 4,844 idle-deserted wells in California (Interstate Oil and Gas Compact Commission, 2020). For comparison, another study by Nelson and Fisk (2021) estimated that there were approximately 1,400 idle-deserted wells in California in 2006. **Figure 6.4** shows the net change of number of oil and gas wells producing each month compared to the same month from the prior year.

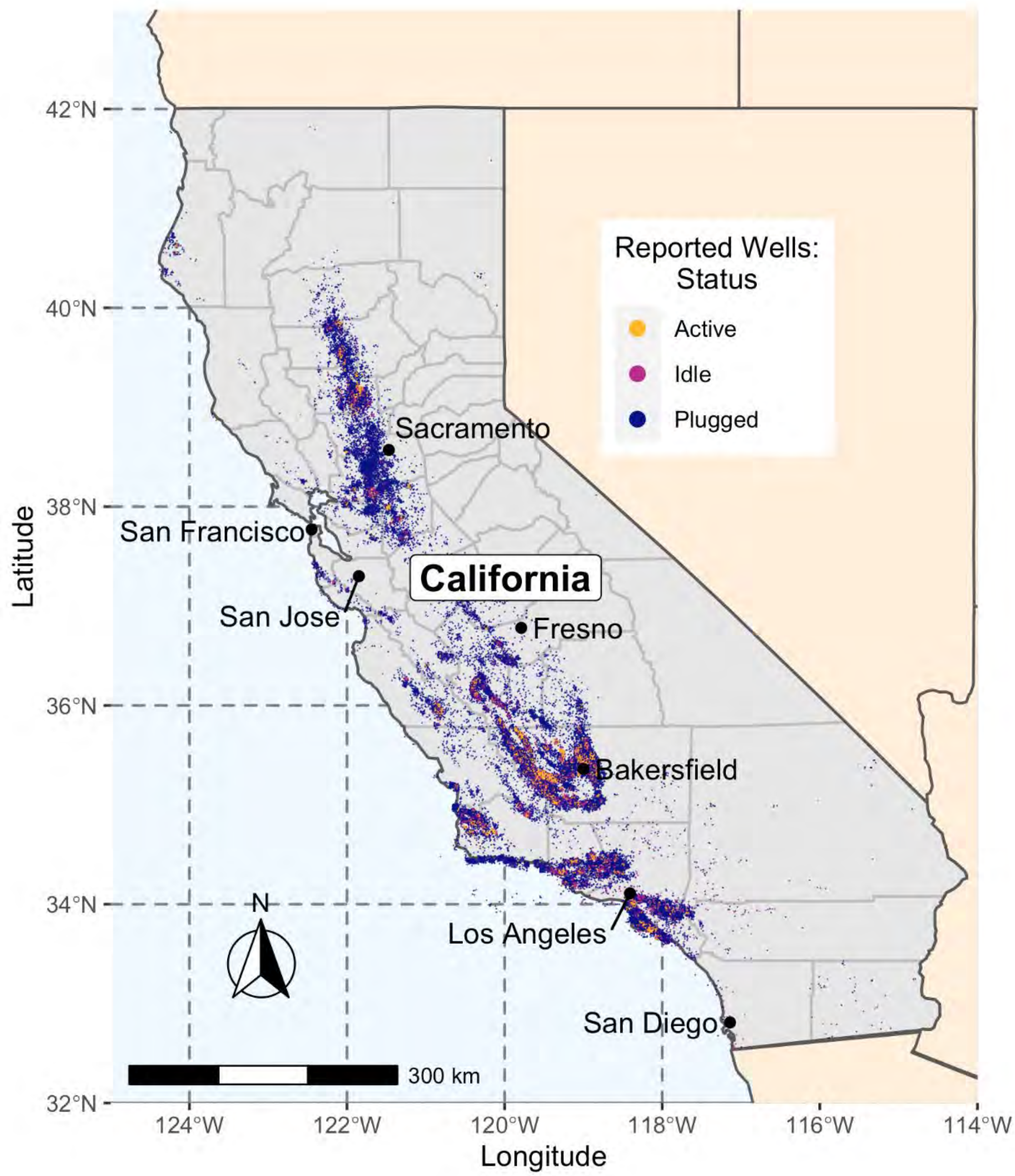

Figure 6.2. Location of active, idle, and plugged wells in California. Source: Adapted from Lebel et al. (2020).

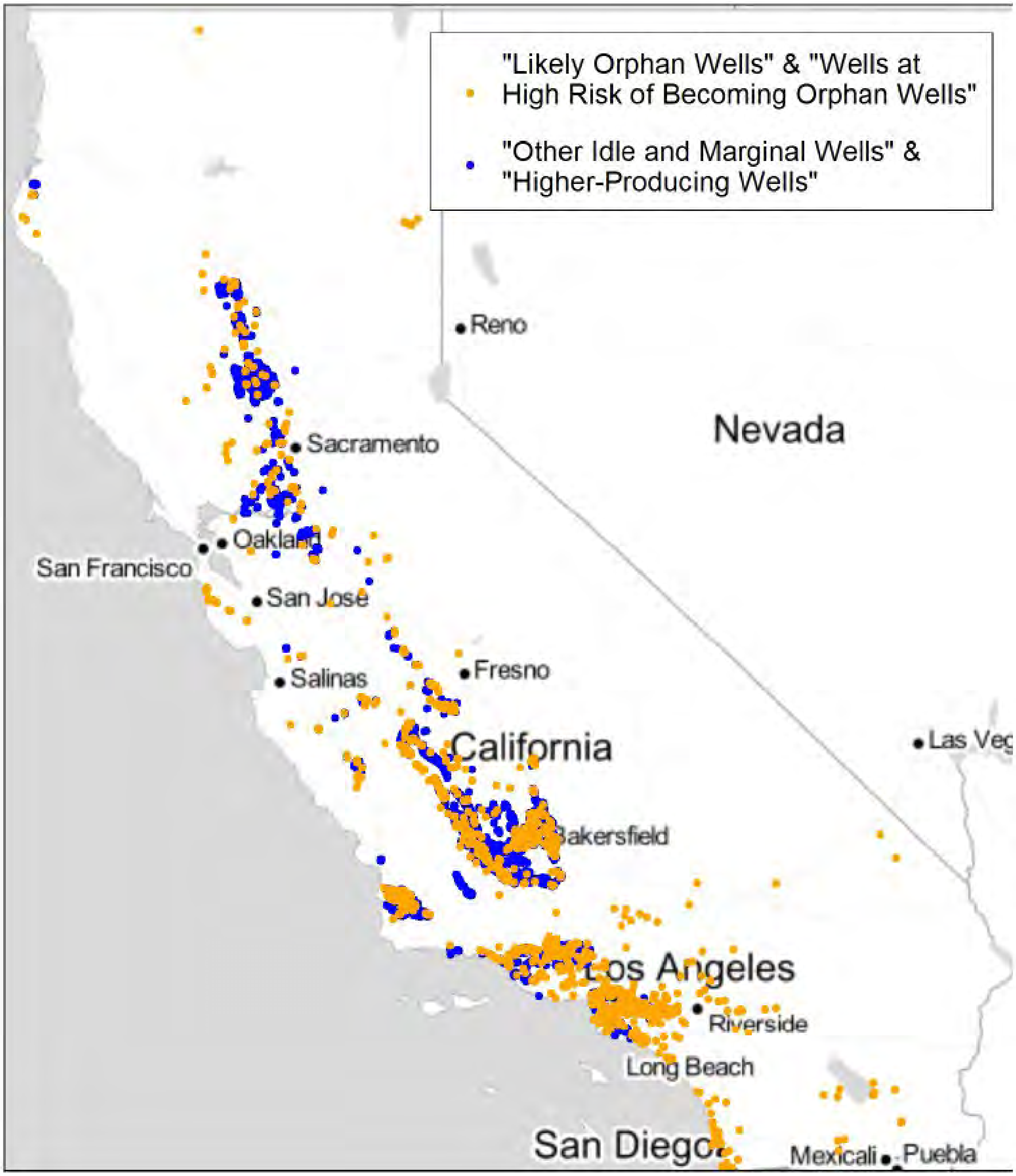

Figure 6.3. Location of likely idle-deserted wells (referred to in this report as "orphaned") and wells at high risk of becoming idle-deserted in California. Source: CCST (2018).

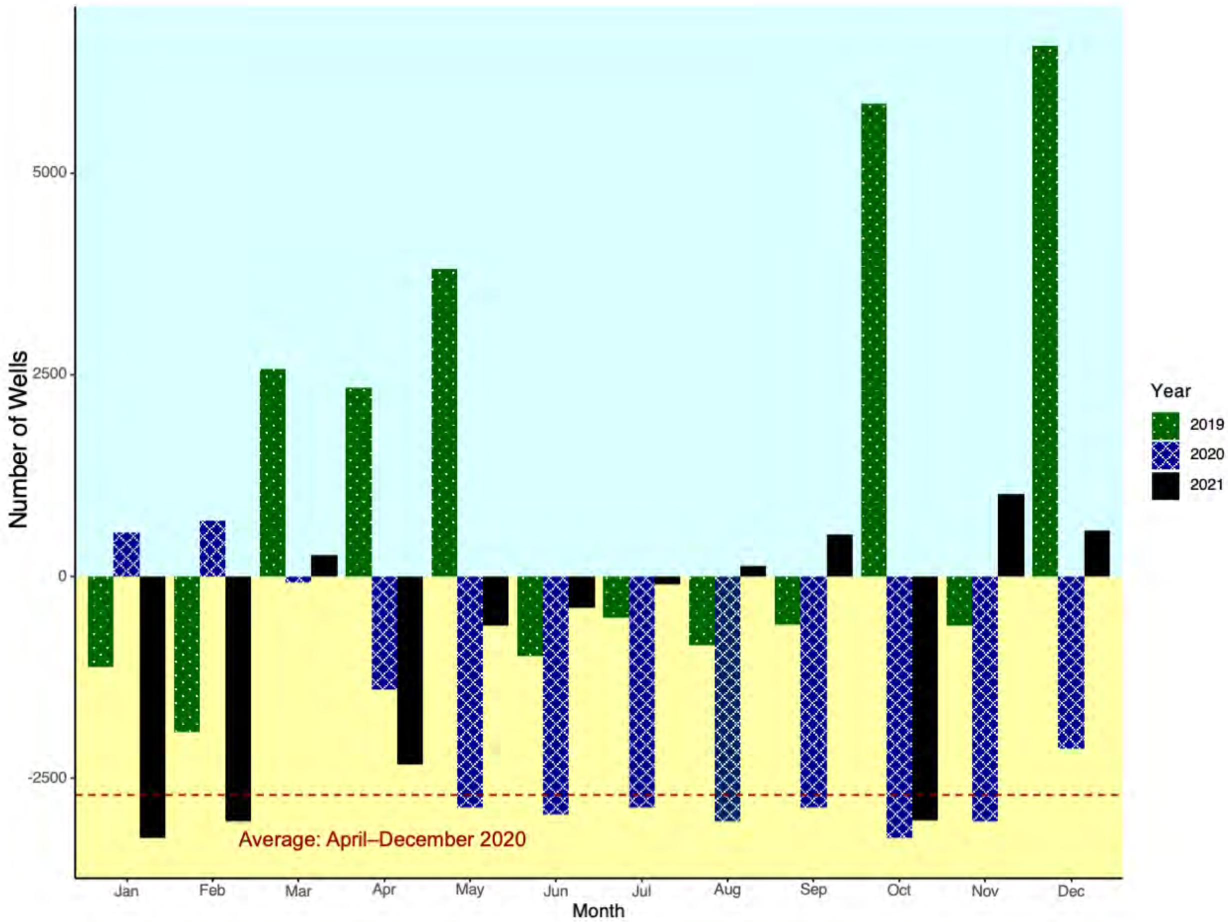

Figure 6.4. Net change in the number of oil and gas wells producing each month compared to the same month from the prior year. Positive values indicate a net increase in the number of wells producing, and negative values indicate that fewer wells were producing over the same month in the previous year. Source: Production data reported by CalGEM from 2018–2021 (CalGEM, 2022b).

6.2.4. Number and Location of Legacy Pipelines and Associated Infrastructure

CalGEM is currently in the process of mapping the locations of active pipelines, tanks, vessels, and other associated oil and gas infrastructure. Under 14 California Code of Regulations (C.C.R.) § 1774.2, operators must provide lists and maps of any active pipelines that pass through sensitive areas, environmentally sensitive areas, urban areas, and designated waterways as part of their pipeline management plans (14 C.C.R. § 1774.2, 2018). Similarly, under 49 Code of Federal Regulations (C.F.R.) 192.727 and 195.59, operators of pipelines that pass under, over, or through a commercially navigable waterway are required to submit data on pipeline abandonment to the National Pipeline Mapping System (49 C.F.R. § 195.59, 2019; 49 C.F.R. § 192.727, 2010; Research and Special Programs Administration, 2000). This data will provide a record of active pipelines in areas with the highest potential to impact human health, however, it does not address the current state of abandoned pipelines and infrastructure, nor take into account future land use scenarios. Idle, abandoned, removed, idle-deserted, and deserted pipelines are not active and not reported by any operators in their pipeline management plans (CalGEM, personal communication, 2021).

We are not aware of any publicly available database of abandoned pipelines, flowlines, gathering lines, or other associated abandoned oil and gas infrastructure that falls under CalGEM's jurisdiction. An assumption could be made that there are at least one or two pipelines for every active or idle well in California, and that the average length and number of pipelines associated with idle and idle-deserted wells is the same as those associated with active wells (CalGEM, personal communication, 2021). The same assumptions cannot be made for abandoned wells. Under 14 C.C.R. § 1776, well site and lease restoration requires operators to remove all tanks, aboveground pipelines, debris, and other facilities and equipment within one year of plugging and abandonment of the last well (14 C.C.R. § 1776, 2006). Underground pipelines can be abandoned in-place after they are purged of oil and filled with an inert fluid. It is estimated that underground pipelines associated with wells are buried between 3–6 ft (91–189 cm) deep, with an average depth of 4 ft (122 cm) (CalGEM, personal communication, 2021). Gathering lines and flowlines in rural areas are likely to be routed above ground (and likely to be removed during lease restoration), while those in sensitive areas or urban areas are more likely to be routed underground (CalGEM, personal communication, 2021). Less is known about pipeline removal practices for legacy abandoned wells, which were abandoned before modern well abandonment requirements were put into effect in 1978. In some areas, cleanup and removal of abandoned pipelines from legacy oil and gas wells is an ongoing operation, as erosion continually exposes legacy infrastructure (California State Lands Commission, 2020).

6.3. Health and Safety Hazards, Risks and Impacts Associated with Idle, Idle-deserted and Abandoned Wells

Idle, idle-deserted, and abandoned wells can pose a risk to human health in several ways. Oil, gas, and other naturally occurring chemicals and radioactive materials can migrate through a variety of leakage pathways associated with these well types, resulting in gas emissions to the atmosphere or the contamination of groundwater or surface water resources. Abandoned and idle wells may also act as conduits for well stimulation fluids or pressurized steam from nearby operations to reach the surface or leak into surrounding groundwater resources. This could directly impact human health, depending on the proximity of these wells to human populations and the nature and extent of the leakage.

UIC project reviews include an evaluation of plugged and abandoned as well as idle wells that could potentially act as conduits. If they are found to be conduits they must be monitored, remediated, or plugged and abandoned. Conduit analysis (including analysis and potential remediation of abandoned wells) is also done as part of the aquifer exemptions mentioned in Chapter 5. Nevertheless, there are leaks that may remain undetected for extended periods of time (Kang et al., 2019). As abandoned wells age, they may become more prone to failure from a combination of catastrophic events (such as earthquakes) and/or the accumulation of small-scale and large-scale failures (Kang et al., 2019). Failures in wellbore integrity can result in leaks and may be due to a wide variety of chemical, mechanical, and physical factors, such as thermal stress, pressure changes, poor cementing and abandoning operations, thread leaks, and the corrosion and dissolution of cement in acidic environments (Kang et al., 2019). Potential leakage pathways for abandoned wells are illustrated in **Figure 6.5**, and include leakage through cement plugs or casing cement, between the casing, cement, and/or surrounding reservoir rock, and along any shear zones that pass through the wellbore. Current standards require that wells have multiple layers of casing and cement to mitigate potential leakage pathways; however, wells can still be susceptible to leakage, particularly due to the corrosive effects of hydrogen sulfide on steel casings and cement, or poor well completion and abandonment procedures (Chilingar & Endres, 2005). Legacy abandoned wells may not have been constructed (or abandoned) to current standards and may have an increased potential for well leakage.

The process of abandoning (or re-abandoning) wells also carries the risk of loss of well control, which has the potential to impact public health through the release of crude oil to the environment or the release of gas and toxic air contaminants (TACs), causing fires, explosions, or impacting air quality (California State Lands Commission, 2017). For example, on January 11, 2019, a contractor was re-plugging a 1930s era gas well in Marina del Rey that was abandoned in the late 1950s (Department of Conservation, 2019). The well was located within 30 ft (9 m) of a sidewalk, 50 ft (15 m) of a road, and 100 ft (30 m) of residences. In the process of pulling tubing out of the well, pressure built up and blew a column of gas, water, and mud 100 ft (30 m) into the air (Department of Conservation, 2019). To minimize this risk, CalGEM may require the use of blowout preventer equipment during abandonment operations (14 C.C.R. § 1723 (e), 2006); however, in this case an estimated 100,000 ft^3 (2830 m^3) of gas was released before the blowout preventer was used to seal the well. Failure of blowout preventer equipment, while rare, does happen, but it should be noted that the blow out preventer itself is not the only means of well control. Additionally, blowout preventers are connected to the top of the well casing and are not intended to protect from leakage from the outside of the casing (California State Lands Commission, 2017). Loss of well control, while generally uncommon, may be more problematic when re-abandoning legacy abandoned wells, as reservoirs may re-pressurize over time and records of well construction and abandonment may not always be available (California State Lands Commission, 2017).

Idle and abandoned wells may also contribute to the formation of surface expressions in oilfields undergoing cyclic steam stimulation. Surface expressions are the release of steam, water, oil, or soil from the subsurface to the surface and may take the form of steam outlets, puddles or streams of oil, or sinkholes filled with steam and other noxious gases (Pollack et al., 2020). Surface expressions are a hazard to oilfield workers and were responsible for the death of one oilfield employee in California. There are many possible causes for surface expressions in California, including active and abandoned wells acting as conduits, natural faults or induced fractures, and fluid flow in porous media along structural features (Pollack et al., 2020). A study of surface expressions in the Midway-Sunset oilfield in Kern County found that surface expressions are significantly associated with the density of plugged wells (Pollack et al., 2020). High densities of poorly plugged abandoned wells could act as a conduit for steam and oil migration, or might be indicative of other underlying geologic factors that contribute to both surface expressions and well abandonment (Pollack et al., 2020).

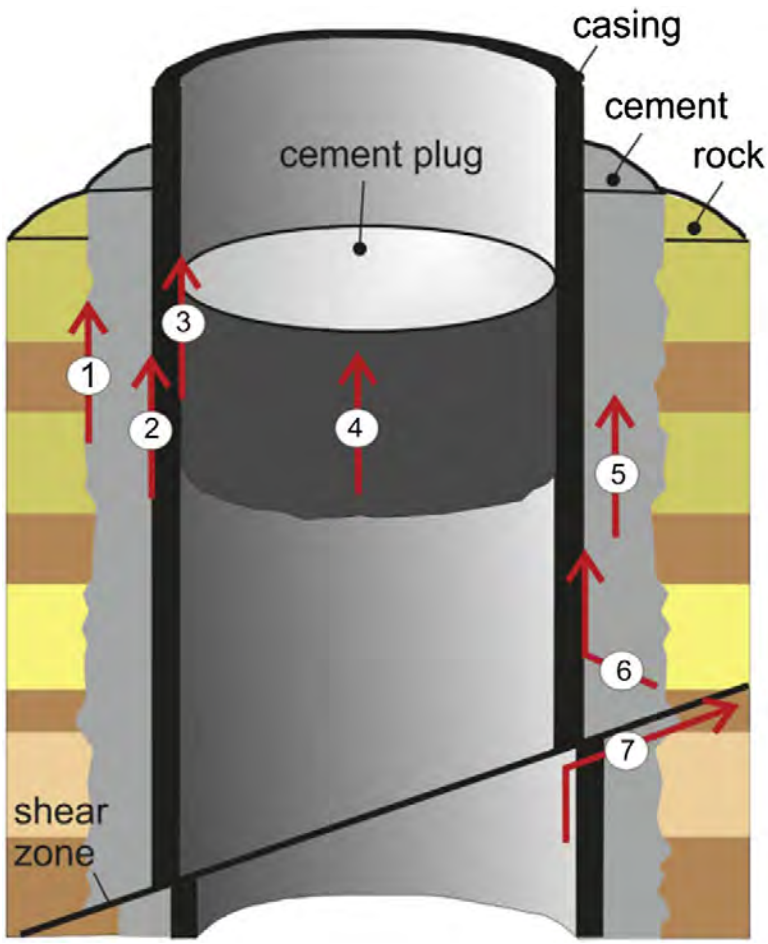

Figure 6.5. Potential leakage pathways for plugged and abandoned wells. (1) Between cement and surrounding formation; (2) between casing and cement; (3) between cement plug and casing/production tubing; (4) through cement plug; (5) through cement; (6) across cement and then between cement and casing; and (7) along a sheared wellbore. Source: Alboiu and Walker, (2019).

6.3.1. Air Pathways

Idle, idle-deserted, and abandoned wells present many of the same public health and safety risk factors as active wells. Wells can serve as a conduit for fluid migration from reservoir cavities deep within the Earth, creating the potential for crude oil, gas, formation water, and volatile organic compounds (VOCs) to reach the surface and be released into the atmosphere (CCST, 2018; CCST et al., 2015; Townsend-Small & Hoschouer, 2021). Emissions of volatile components from idle, idle-deserted, and abandoned wells can include methane, VOCs and other TACs, criteria pollutants, gaseous NORM, and reactive organic gases, which are associated with the formation of tropospheric ozone (i.e., smog). In addition, when idle, idle-deserted, and abandoned wells have inadequate well casing and cement plugging practices, legacy abandoned wells, in particular, are susceptible to acting as conduits for gas to seep to the surface from reservoir cavities (Chilingar & Endres, 2005). However, the lack of production and associated pumps, generators, compressors, pneumatic devices, storage tanks, and surface impoundments mean that the overall combined emissions footprint from idle, idle-deserted, and abandoned wells is smaller than active wells. There is no documentation that emissions from chemical mixing and spills are major concerns, since these chemical additives are only used during well development and rework. But emissions from idle, idle-deserted, and abandoned wells may still result in regional air quality impacts and increased exposure to populations in close proximity.

In California, most studies of emissions from idle, idle-deserted, and abandoned wells have focused on methane. Although methane is not a TAC, it is a potent greenhouse gas, as well as an asphyxiant and an explosive hazard with a lower explosive limit of approximately 5% by volume (Chilingar & Endres, 2005). Methane buildup from leaking abandoned wells has been responsible for explosions that destroyed houses in Trinidad, Colorado, in 2007 (COGCC, 2008). Methane buildup also was possibly responsible for the Ross Dress for Less explosion in Los Angeles in 1985, which was linked to subsurface gas accumulation associated with a nearby oil well, but the source is still debated (LACDPH, 2018). Other instances of legacy abandoned wells acting as conduits for gas to seep to the surface in residential and commercial areas from underground gas storage facilities have been documented in the Los Angeles area (Chilingar & Endres, 2005).

Methane emissions from abandoned wells in California were most recently measured by Lebel et al. (2020). They measured methane emissions from 97 plugged and abandoned wells, 17 idle wells, six active wells, and one unplugged and abandoned well; the results are summarized in **Table 6.2**. They found that while emissions from plugged and abandoned wells are generally low, emissions from idle wells were more than two orders of magnitude greater. These idle wells were idle for an average of 13.9 years, with a range of 6–39 years. Similar to studies in other regions, emissions from both abandoned and idle wells followed a "long-tailed distribution," with a few wells responsible for the majority of emissions. The top three plugged and abandoned wells emitted 99.6% of emissions from all plugged and abandoned wells; the top two idle wells emitted 74.1% of emissions from all idle wells. Active wells had the highest emissions and values were generally consistent with previous studies by Jeong et al. (2014) and Zhou et al. (2021), which estimated active wells in California emit 0.168 teragrams per year of methane (Tg/yr CH_4) (1.1 million tons per year), and wells in Northern California emit 7.6 kilograms per day of methane (kg/day CH_4) (17 pounds per day), respectively.

Table 6.2. Mean methane emissions from various well types in California when emissions were detected. Source: Lebel et al. (2020)

Well Status	Number of detects/ Number of wells sampled	CH_4 Emissions (g/hr)
Plugged and Abandoned	34/97	0.286
Idle	11/17	35.4
Unplugged and Abandoned	1/1	10.9
Active	4/6	189.7

Most recently, in May 2022, residents of Bakersfield reported symptoms of dizziness, fatigue, and headaches, and noticed a hissing sound coming from a nearby oil well (Secaira, 2022). CalGEM investigated this well — classified as idle — and determined it was leaking. After further investigation, at least 44 additional idle wells in Bakersfield were found to be leaking methane. Evidence from other groups demonstrated that some of these wells were found to be leaking methane at rates that produced dangerously explosive levels of methane gas near the wellhead (Solis, 2022). Two months later, the Department of Conservation noted that 44 of the 45 wells had been completely repaired and one well was still found to be leaking methane, despite having undergone repairs. In August 2022, an additional 9 idle wells — three in Kern County and six in Los Angeles County — were found to be leaking methane. Eight of these wells were repaired within a week (California Department of Conservation, 2022). Situations like these, where private citizens find leaking wells in close proximity to their homes, further emphasizes the potential hazards of oil and gas wells — even idle wells — on the health and safety of the public.

6.3.1.1 Volatile Organic Compounds and Toxic Air Contaminants

Current studies of VOC and TAC emissions, such as benzene, toluene, ethylbenzene, and xylenes (BTEX) and n-hexane, from idle and abandoned wells in California are limited in scope and geographic coverage. Lebel et al. (2020) measured benzene emissions at a single unplugged well in California, but the levels were below the detection limit of 4.2 parts per billion by volume (ppbv). In 2016, the South Coast Air Quality Management District (SCAQMD) measured VOCs, methane, and hydrogen sulfide from two idle-deserted wells in a residential area of Echo Park prior to abandonment (SCAQMD, 2016). Concentration of hydrogen sulfide inside one of the wells was above the acute reference exposure level (REL) of 30 parts per billion (ppb) and methane levels were above the lower explosive limit (LEL) of 5%. VOCs were below acute RELs, with the exception of acrolein. It should be noted that acrolein is known to be difficult to measure with current U.S. EPA TO-15 methods (SCAQMD, 2016), and concentrations measured inside wells are not representative of concentrations in the surrounding ambient air. To our knowledge, no major studies have systematically measured statewide VOC and TAC emissions from idle or abandoned wells in California.

As discussed in Chapter 4, Section 4.2.1, VOC and TACs are not typically measured when determining gas composition in California. However, benzene and hydrogen sulfide were measured and detected in gas from select wells in the San Joaquin Valley (Lillis et al., 2007). VOCs have also been measured downstream of wells in the process of determining emissions inventories, but it is difficult to elucidate how representative those values are of emissions from wells in California.

Without additional data, it is challenging to determine how prevalent — and at what concentrations — TACs and other VOCs are present in emissions from idle, idle-deserted, and abandoned wells in California. However, as discussed in Chapter 4, Section 4.2.1, VOCs and TACs have been observed in gas from active wells in other parts of the country (Brantley et al., 2015; El Hachem & Kang, 2022; LACDPH, 2018; Lillis et al., 2007; Tran et al., 2020) and we can generally assume that anytime there exists a pathway for gas to escape to the atmosphere, there is the potential for

VOCs and TACs to be released as well. Additional testing and public disclosure of the composition of VOCs and TACs from idle, idle-deserted, and abandoned wells are needed to assess air pollution health risks and better inform policy makers.

In 2019, California passed Assembly Bill 1328, which calls for a study of fugitive emissions from idle, idle-deserted, and abandoned wells in California (Assembly Bill No. 1328, 2019). The results of this study have not been released to date. In 2018, the California Air Resources Board (CARB) started their Study of Neighborhood Air near Petroleum Sources (SNAPS) program. The SNAPS program does not specifically target emissions from abandoned or idle wells, but will provide data on upstream emissions of VOCs, hazardous air pollutants (HAPs), and other criteria pollutants from oil and gas operations in California (CARB, 2018, 2021).

6.3.2. Water Pathways

Abandoned wells, some of which were constructed prior to the implementation of current well construction standards, may be particularly prone to leakage along the wellbore (USGS, 2014). As wells age, failures in wellbore integrity can result in subsurface pathways whereby oil, gas, and formation water can contaminate groundwater resources through subsurface migration. Due to the large number of abandoned wells in California, failure of even a small percentage could result in a large number of potential subsurface migration pathways (USGS, 2019). A review of groundwater contamination from oil and gas development by the Ground Water Protection Council (2011) found that abandoned wells accounted for 14% and 22% of groundwater contamination events in Texas and Ohio, respectively. No similar studies have taken place in California. However, the USGS California Water Science Center is currently working together with state and federal agencies on the California Oil, Gas, and Groundwater Program to monitor potential contamination of groundwater resources near oil fields.

While developing the Underground Injection Control (UIC) Program regulatory framework, the U.S. EPA recognized that injected fluids could potentially migrate into Underground Sources of Drinking Water (USDW) (Osbourne, 2002). The vertical migration of injected fluids through improperly abandoned and improperly completed wells that penetrate the injection zone may cause groundwater contamination and impacts to domestic or municipal water wells (Osbourne, 2002). Although this report focuses on drinking water wells, any abandoned oil or gas well that passes through USDW has the potential to act as a conduit.

Similarly, abandoned and idle wells can act as a potential migration pathway for oil and gas, formation water, chemical additives, and cleanout fluids during well stimulation and well cleanout activities (CCST et al., 2015). Fractures created during well stimulation can hydraulically connect a stimulated well to nearby abandoned or idle wells; this is of particular concern in high-density fields and those with a long history of oil and gas operations (CCST et al., 2015). These nearby abandoned or idle wells must also fail in order for a pathway to the surface or surrounding groundwater resources to be present. Under 14 C.C.R. § 1784, operators must identify any existing wells that could be impacted from well stimulation operations (14 C.C.R. § 1784, 2015); however, 14 C.C.R. § 1784 does not require testing the integrity of idle wells (CCST et al., 2015).

But idle well regulations call for these wells to be tested. Additionally, current well stimulation risk assessments — conducted according to well stimulation treatment (WST) regulations — require accounting for and addressing any potential fluid migration pathways before a WST permit is issued. But abandoned wells continue to pose a risk of acting as a migration pathway due to the lack of monitoring requirements post abandonment.

Abandoned wells may be particularly susceptible to subsurface failure due to land deformation from seismic activity or subsidence (USGS, 2019). A geospatial analysis of well locations and earthquakes in California was done by Kang et al. (2019). They found two hotspots in California where seismic activity and oil and gas wells overlap: the southern Central Valley and Los Angeles County. There are no studies that investigate the relationship between seismic activity and wellbore integrity (Kang et al., 2019). However, abandoned wells may present an increased risk of subsurface leakage from seismic activities (compared to active wells) due to their age; lack of monitoring and management requirements; and incomplete records regarding location and wellbore integrity. Similarly, land deformation due to the injection of wastewater, steam and water flooding, or the withdrawal of petroleum or groundwater resources, can also cause wells to fail (USGS, 2019).

Box 1. Direct exposure to crude oil and VOCs from leaking legacy abandoned intertidal wells

Improperly abandoned legacy oil and gas wells near waterways and other surface waters can leak oil directly into coastal and aquatic environments. Oil leaking directly on the beach or into shallow nearshore waters can create oil sheens on beaches and in waters that can come in direct contact with surfers, swimmers, and others engaged in recreational activities. Additionally, the volatile fraction of crude oil is expected to rapidly volatilize and become air pollutants, resulting in odor complaints, unhealthy air quality, and negative health impacts. This is a particular problem along areas of the California coast with a long history of oil and gas development that are also widely used for recreation. For example, in Summerland Beach near Santa Barbara, multiple improperly abandoned legacy onshore and offshore wells from the early 1900s have been observed seeping oil directly onto the beach and into the ocean (California State Lands Commission, 2017, 2020). Nearby residents and visitors have complained of oil sheens, strong petroleum odors, headaches, and nausea, and the Santa Barbara County Public Health Department has closed the beach on occasion to protect public health (California State Lands Commission, 2017). Onshore clean-up and well re-abandoning efforts have been occurring along the Summerland coast since the 1960s; however, only recently have efforts been made to address oil leakage from improperly abandoned legacy wells in intertidal zones and shallow offshore wells (California State Lands Commission, 2017, 2020). In 2018, the Becker well became one of the first legacy abandoned wells in the intertidal zone to be successfully re-abandoned. Prior to re-abandonment, leakage from the Becker well was a known issue — a U.S. Coast Guard evaluation from 1994 estimated that approximately 0.5 barrels (80 liters) of crude oil a day were leaking onto the beach and into the ocean from the legacy well (California State Lands Commission, 2017). Although offshore wells are outside the scope of this report, legacy abandoned wells located in intertidal zones that are above water part of the time and submerged at other times, can have direct impacts on the health of nearby residents and visitors engaging in recreational activities on the beach or in the ocean. The re-abandonment of intertidal wells presents unique challenges that increase overall costs and delay their timely completion, resulting in extended periods of leakage and potential human health impacts.

6.3.3. Idle, Idle-deserted, or Abandoned Wells Examined in the Epidemiological Literature

6.3.3.1 Epidemiological studies conducted in California

The environmental public health literature strongly supports geographic proximity to active oil and gas development as an important risk factor for a variety of adverse health outcomes. However, very few of these studies take into account idle (or inactive) wells and, to the best of our knowledge, no epidemiological studies in the United States have taken into account abandoned wells or associated legacy infrastructure. Five peer-reviewed epidemiological studies with a focus oil and gas development have been conducted in California, three of which include idle or inactive wells in their analysis (Johnston et al., 2021; Tran et al., 2020). A brief summary of these study results with regard to idle or inactive wells is provided below; a more in-depth summary of these studies is provided in Chapter 3.

Tran et al. (2020) and Tran et al. (2021)

Tran et al. (2020) evaluated adverse birth outcomes among infants born between 2006 and 2015 to mothers living near active and inactive wells in the San Joaquin Valley and South Central Coast and South Coast Air Basins. Exposure to inactive wells, defined as any well not producing at least one unit of oil/gas in a given month, was characterized by well counts within 1 km (3,281 ft) of maternal residence at time of delivery. Tran et al. (2020) found no association between inactive well counts and adverse birth outcomes among both urban and rural populations. This may have been because well count alone was not sufficient to capture nuanced exposure pathways associated with idle wells, leading to potential exposure misclassification (Tran et al., 2020). This study controlled for potential confounding variables, including community-level factors and individual-level factors for infants (sex, month/year of birth) and mothers (age in years, race/ethnicity, education level, Kotelchuk index of prenatal care, child parity).

In a similar study, Tran et al. (2021) evaluated the association between proximity to hydraulically fractured wells with the same health outcomes, population, and time frame as Tran et al. (2020). Exposure to hydraulically fractured wells was associated with increased odds of low birth weight, preterm birth, lower term birth weight, and small for gestational age, particularly among rural mothers. The exposed group included exposure to active and/or inactive wells; however, inactive wells were not isolated from active wells and no conclusions were drawn specific to inactive wells.

Johnston et al., 2021

Johnston et al. (2021) evaluated lung function and self-reported acute health symptoms among residents living near the Las Cienegas oil fields in South Los Angeles. Patterns in reduced lung function were seen among participants living near active and idle wells, although it was more pronounced in communities near active wells. Even after adjusting for age, sex, height, proximity to freeway, asthma status, and smoking status, Johnston et al. (2021) found that living nearby and downwind of oil and gas development sites, active or idle, was associated with reduced lung function among residents.

6.3.3.2 Epidemiological studies conducted outside of California

Our review of 43 epidemiological studies related to oil and gas development in other states found only one study that was distantly related to inactive wells. Currie et al. (2017) examined birth weights for women living in Pennsylvania from 2004 to 2013 with respect to proximity of hydraulically fractured wells. They found negative impacts to mean term birth weight and increased incidents of low birth rate in babies whose mothers lived within 3 km (1.86 mi) of hydraulically fractured wells. When the study was adjusted to take into account inactive wells that may have been active during the study period (2004–2013), rather than just in 2014, they found no differences in the results.

The environmental public health literature that takes into account idle and abandoned wells is limited. There is evidence that geographic proximity to idle wells may be a risk factor for reduced lung function; however, this is the result of a single study. There is insufficient data to draw conclusions about abandoned wells as a risk factor for adverse health outcomes. Additional epidemiological studies that take into account idle and abandoned wells would increase the understanding of underlying exposure sources and pathways as well as elucidate which types of wells may be of the greatest concern with regard to human health outcomes (Tran et al., 2020). This data could then be used to inform future regulatory decisions to reduce community exposure from various types of wells.

6.3.4. Regulations

This section discusses many of the regulations in place for abandoned and idle wells. These descriptions are not meant to be exhaustive; rather, they are meant to provide descriptions of the current regulations and insight for future regulations.

In 2019, CalGEM (formerly the Division of Oil, Gas, and Geothermal Resources [DOGGR]) updated idle well regulations to require testing of idle wells in order to further protect public safety and to increase incentives for operators to plug and abandon idle wells (CalGEM, 2019). Operators are required to test idle well fluid levels for wells that penetrate a USDW within 24 months of a well becoming idle and every 24 months thereafter (14 C.C.R. § 1772.1(a)(1), 2019). If idle well fluid levels are above the base of a USDW, operators must perform a casing pressure test to a depth 100 ft (30 m) above the uppermost perforation, top of the landed liner, or above the casing shoe of the deepest cemented casing. Pressure tests must be repeated every 48, 72, or 96 months depending on the pressure tested. Operators are also required to demonstrate the ability to reach an approved depth of the well within eight years of a well becoming idle, and every 48 months thereafter. Idle wells that fail testing must be either brought into compliance, partially or fully plugged and abandoned, or be scheduled for plugging and abandonment under an Idle Well Management Plan within 12 months.

Operators are required to pressure test all idle wells within 24 months of a well becoming idle. After April 1, 2025, if the fluid level in an idle well is above a USDW, then the well must be pressure tested on an expedited, 90-day timeframe (14 C.C.R. § 1772.1(a)(2), 2019). The engineering analysis includes pressure testing and clean out tag in addition to information on geologic units, producing zones, USDW and freshwater aquifers, faults, and containment features. If it is determined that a long-term idle well is not viable to return to operation, the operator must plug and abandon the well within 12 months or schedule it for plugging and abandonment under an Idle Well Management Plan or an approved Testing Waiver Plan.

California's requirements for plugging and abandoning wells are similar to those in Texas and Colorado. Plugging and abandoning oil and gas wells is regulated under 14 C.C.R. § 1723 and P.R.C. § 3208 (14 C.C.R. § 1723, 2016; P.R.C. § 3208, 2017). Briefly, cement plugs must be placed at specified intervals to protect and isolate oil and gas zones, usable freshwater resources, and to protect surface conditions and public health and safety. Mud fluid must be poured into intervals not plugged with cement and into all open annuli to prevent movement of other fluids into the wellbore. At the surface, the hole and annuli must be plugged, well casing should be cut off 5 to 10 ft (1.5 to 3 m) below the surface of the ground, and a steel plate must be welded to the top of the casing. Casings should be recovered when possible.

Operators may partially plug and abandon a well to reduce idle well testing requirements (14 C.C.R. § 1752, 2019). Partially plugged onshore wells must meet all the same requirements as fully plugged and abandoned wells with the exception of requirements for surface plugging, casing recovery, and post-plugging environmental inspections. Partially plugged wells must be pressure tested when they become a long-term idle well, or by April 1, 2024, and every 60 months thereafter. Partially plugged wells are not required to undergo engineering analysis. A partially plugged and abandoned well provides similar isolation of oil and gas producing zones and protection for groundwater as a fully plugged and abandoned well.

The plugging and abandonment of idle-deserted wells is based on protocols described in the CalGEM report *Orphan Well Screening and Prioritization Methodology* (CalGEM, 2023). Idle wells are prioritized for testing or plugging and abandonment based on the age of the well, if the fluid level of the wells is above the base of a USDW or freshwater, any downhole issues that would prevent reactivation or plugging, economic or operational efficiencies, if the well is a critical well or located near geologic hazards, urban areas, or environmentally sensitive areas, or if the well poses a threat to life, health, property, or natural resources. Critical wells are defined as wells within 300 ft (91 m) of a building intended for human occupancy or airport runway, or 100 ft (30

m) of a public recreational facility or area of periodic high-density population, navigable body of water, public street, highway, or railway, or a wildlife preserve (14 C.C.R. § 1720, 2006).

In 2019, California passed Assembly Bill 1328 (2019), which requires CalGEM and CARB to conduct a study of fugitive emissions, including TACs and VOCs, from a representative sample of idle, idle-deserted, and abandoned wells. The results of this study have not been published. To the best of our knowledge, there are no long-term monitoring requirements for plugged and abandoned wells in California or in other states, though some California municipalities require leak testing and visual inspection of abandoned wells prior to the development of an area (City of Carson, 2021; City of Signal Hill, 2020).

There is no agency that currently regulates emissions from abandoned and plugged wells, although CalGEM recently implemented a regulation for idle wells — 14 C.C.R. § 1772.1 — as described above. In 17 C.C.R. § 95665-95677 (2017), CARB has laid out regulations for emissions from oil and gas infrastructure, including Leak Detection and Repair (LDAR). CARB explicitly exempts abandoned wells from these requirements, defining a well in § 95667 as:

> ”Well” means a boring in the earth for the purpose of the following:
> (A) Exploring for or producing oil or gas.
> (B) Injecting fluids or gas for stimulating oil or gas recovery.
> (C) Re-pressuring or pressure maintenance of oil or gas reservoirs.
> (D) Disposing of oil field waste gas or liquids.
> (E) Injection or withdraw of gas from an underground storage facility.

For the purpose of § 95667, wells do not include active observation wells as defined in P.R.C. § 3008 subdivision (c), or wells that have been properly abandoned in accordance with P.R.C. § 3208.

According to California definitions above, a well must have no production for 24 consecutive months to become classified as an idle well, so until then the well would remain subject to the regulations noted above.

There is currently no regulation of groundwater contamination from poorly or improperly abandoned wells. Current regulations specify that a properly abandoned well should have a cement plug above and below the aquifer layer in the plugged well. But as noted earlier in this section, many wells have not been properly abandoned, are unrecorded, or the plugging materials may fail over time, all leading to a possibility of increased groundwater contamination.

6.4. Health and Safety Hazards, Risks and Impacts Associated with Legacy Infrastructure

Oil and gas pipelines and associated infrastructure that are abandoned in-place will inevitably corrode and lose structural integrity (Crosby et al., 2015). Any persistent residual contaminants within the pipeline or associated components that outlive the rate of deterioration are at risk of release into the surrounding environment. Other potential hazards associated with the in-place abandonment of pipelines include the drainage and subsequent contamination of surface water or groundwater through pipelines, ground subsidence due to failing structural integrity, and physical exposure and damage to pipelines from erosion, geohazards, or hydrotechnical hazards (Arcadis Canada, 2019). It is predicted that, for the United States at large, problems associated with legacy oil and gas infrastructure will increase in the future due to hydraulic fracturing and the expansion of production from shale in the past decade (Federal Facilities Research Center Radiation Focus Group, 2014). It is also the case that pipeline abandonment regulations have been in place for some time, with the potential result that pipelines on the surface in rural or undeveloped areas are likely removed and underground pipelines that are generally found in developed urban areas have been abandoned in place after flushing and "inerting." When this is the case, only very old abandoned and, in some cases, insulated pipelines are likely to have residual contaminants. We expect pipelines in the oil fields of California to be above ground when it is more economical to run them on the surface, unless the pipelines run thorough public or private property.

6.4.1. Hazards Associated with Legacy Abandoned Pipelines and Infrastructure

As abandoned oil and gas pipelines and infrastructure corrode over time, contaminants that may be released into the environment include components of the oil and gas transfer stream deposited scales, naturally occurring radioactive materials (NORM) and technologically enhanced naturally occurring radioactive materials (TENORM), treatment chemicals, pipe coatings, and metals due to corrosion (Thorne et al., 1996). A list of possible contaminants is provided in **Table 6.3**. Contaminants released into the environment may leach into underlying groundwater resources, seep up to the surface where they may volatilize or impact water resources, or become airborne as particulates from excavation or exposure due to erosion. Human health impacts associated with the release of treatment chemicals, components of oil and gas, NORM, and TENORM to the environment are discussed previously in Chapters 2, 4, and 5.

NORM, TENORM, PCBs, and asbestos are of particular concern due to their documented accumulation or use in legacy pipelines and infrastructure, environmental persistence, and well-documented human health impacts. TENORM/NORM, PCBs, and asbestos are discussed in further detail in the following sections.

As abandoned pipelines corrode and perforations form, they may act as water conduits, channeling surface water, groundwater, and other infiltrated materials to another location (Amec Foster Wheeler Environment & Infrastructure, 2017; Pipeline Abandonment Steering Committee, 1996; Swanson et al., 2010). Water that travels through abandoned pipelines may mobilize any residual contaminants within the pipeline and contaminate soil and water resources down gradient (Amec Foster Wheeler Environment & Infrastructure, 2017; Pipeline Abandonment Steering Committee, 1996; Swanson et al., 2010). Changes in natural drainage patterns could also negatively affect wetland and marsh ecosystems while simultaneously flooding other areas. A literature review conducted on behalf of the Pipeline Abandonment Steering Committee found that although abandoned pipelines becoming water conduits is a commonly cited hazard, there were no documented cases of this actually occurring (Amec Foster Wheeler Environment & Infrastructure, 2017).

Abandoned pipelines that cross or pass alongside waterways and other bodies of water may become exposed due to hydrotechnical hazards including scouring, bank erosion, and flooding or failure of buoyancy control mechanisms (Pipeline Abandonment Steering Committee, 1996; PHMSA, 2019). These abandoned pipelines will be more susceptible to structural failure due to lateral water forces, impacts from debris or watercraft, and erosion of supporting soils. Subsequent releases of contaminants into waterways have the potential to impact large geographical areas and contaminate drinking water resources for downstream communities (PHMSA, 2019). In addition to potential contamination of surface water from pipeline corrosion and failure, these pipelines could pose a physical hazard for recreational and/or commercial activities (Swanson et al., 2010).

Ground subsidence can occur when abandoned pipelines corrode and collapse. Subsidence is primarily a concern for large transmission pipelines (Pipeline Abandonment Steering Committee, 1996). Gathering lines and flowlines, used to transport raw gas, crude oil, and/or produced water from wells to larger connection points and processing facilities, are generally smaller in diameter than transmission lines, and their potential for ground subsidence is expected to be minimal. However, gathering lines and flowlines represent a larger challenge with respect to integrity due to the variety of fluids transported, their more dispersed nature, and difficulties in inspection and monitoring (Godin, 2014).

Table 6.3. Possible contaminants that may be released into the environment by abandoned oil and gas pipelines. Source: Adapted from Thorne et al. (1996).

Category	Subcategory	Examples
Components in oil and gas stream	Hydrocarbons	Cycloalkanes; monoaromatic hydrocarbons; polyaromatic hydrocarbons; polyaromatic sulfonated hydrocarbons, n-hexane, BTEX
	Sulfur compounds	Hydrogen sulfide; carbon disulfide; carbonyl sulfide; mercaptans, including ethylated and methylated forms
	NORM/TENORM	Barium, strontium, radium, uranium, radon decay products: lead-210, bismuth-210, polonium-210
	Metals	Mercury, nickel, vanadium, chromium, arsenic
Deposited scales	Corrosion scale	Iron(II) sulfide, iron oxides, iron(II) carbonate
	Hardness scale	Calcium carbonate, calcium sulfate, barium sulfate
	Other	Asphaltenes, waxes, gums, resins, paraffins, naphthalenes, bitumens
Treatment chemicals	Scale control	Hydrochloric acid, with phosphate-type inhibitor and sodium or ammonium hydroxide neutralizer, xylene, toluene
	Corrosion inhibitors	Kerosene, sodium dichromate, hexametaphosphate, silicates, quaternized amines
	Biocides	Cocodiamine, glutaraldehyde, sodium hypochlorite
	Coolants	PCBs, triaryl phosphates, terphenyls, glycols (propylene; mono, di, and tri ethylene), brine and alcohol-based coolants

Category	Subcategory	Examples
Pipe body and metal wear	Pipe body	Iron (97 to 99% by weight), manganese (0.5 to 2.0% by weight), copper, nickel, molybdenum, chromium, carbon (0.5 to 1.0%), sulfur, phosphorus, tin, lead, bismuth, arsenic, zinc, cadmium, tungsten, magnesium, aluminum, calcium, cerium, silicon, boron (trace)
	Metal wear	Niobium (toughening agent); vanadium, titanium (strength at low temperatures); copper, zinc, chromium, cadmium (compressor wear); aluminum
	Welding rod	Carbon steel, stainless steel, cast iron, copper, brazing copper silicon with phosphor-bronze, brazing naval bronze with manganese-bronze, silver solder, soft solder (primarily lead), and wrought iron
	Sacrificial anodes	Lead, chromium, iron, magnesium, tungsten, aluminum, zinc
Pipe coatings and degradation products	Coal tar	Toluene, xylene, anthracene, and other polycyclic aromatic hydrocarbons
	Wraps	Coal tar enamel, glass or asbestos outer wrap, blown bitumen (asphalt), fiberglass wrap, asbestos felt
	"yellow jacket"	Rubberized asphalt mastic, high density polyethylene, carbon black
	Fusion bonded epoxy	Bisphenol, epichlorohydrin resin, amine or anhydride based hardener, chalk, silica
	"blue jacket"	Chromate pretreatment, epoxy resin, adhesive, high density polyethylene

Abandoned Pipelines and Infrastructure: TENORM/NORM

As discussed in Chapter 2, Section 2.3.3, NORM from the subsurface are typically transported to the surface during oil and gas production with produced water and precipitate out as scale or scale-bearing sludge within piping and upstream infrastructure such as gas dehydrators, oil and water separators, and associated water lines (Department of Health Services Radiologic Health Branch & DOGGR, 1996; The Cadmus Group, 1995; US EPA, 2022b). NORM that becomes concentrated due to oil and gas extraction and processing are generally classified as TENORM. The two radionuclides that are typically present in oil and gas produced water and scale are radium-226 (half-life=1,600 years) and radium-228 (half-life=5.8 years) (USGS, 1999). Scale and incorporated TENORM are usually found in the greatest concentrations in piping in close proximity to the wellhead and other infrastructure that has extended contact with produced water (US EPA, 1991; USGS, 1999). Accumulation is time-dependent, with pipelines in longer service more likely to have greater concentrations.

Building over oil and gas infrastructure creates a range of human exposure scenarios. As discussed in Chapter 2, Section 2.3.3, the immediate concern with TENORM from buried pipelines is gamma radiation exposure, while the major and long-term concern is future land use management redevelopment in areas of buried pipelines (Pipeline Abandonment Steering Committee, 1996). The half-life of radium-226 is 1,600 years, so the use of long-term institutional restrictions is not feasible. Oil and gas fields that do not appear habitable today could contain houses or buildings within 100 years or more. If excavation occurs during construction, in addition to gamma radiation exposure, there is concern of exposure to beta and alpha particles by inhalation of dust during excavation. Furthermore, exposure of buried abandoned pipelines may occur naturally from erosion, geohazards (e.g., earthquakes, landslides), or hydrotechnical hazards (e.g., floods, bank erosion, scouring), increasing potential exposure to TENORM. Since there are likely a large number of pipelines buried in fields in California, this is likely to be a major legacy issue associated with legacy oil and gas development in California.

In the absence of excavation, there is also concern about intrusion of radon-222 gas (half-life=3.8 days) — a decay product of radium-226 — into buildings with subsequent inhalation by inhabitants. The U.S. EPA CERCLA standard for remediation of radium contaminated soils below 15 cm (6 in) is 15 picocuries per gram (pCi/g) above background (40 C.F.R § 192.12, 1995). Since pipelines are expected to corrode and eventually breakdown into the surrounding soil, this standard appears applicable to pipe scale and the long-term, near surface disposal of pipes. In areas of production where gas is retained inside of pipes and other components, lead-210 (half-life=22 years) — a decay product of the gas radon-222 and a beta and gamma emitter — may also accumulate over time; a TENORM issue that can differ from areas associated with scale accumulation (Faria & Moreira, 2016).

TENORM that is less than 0.05% uranium or thorium by weight falls outside of the control of the U.S. Nuclear Regulatory Commission (Ann Glass Geltman & LeClair, 2018). Although the U.S. EPA has provided guidance on the issue of TENROM (US EPA, 2003), they do not currently regulate it (Thompson et al., 2015). A number of states have developed or are developing regulations on the disposal of TENORM associated with oil and gas development — California is not one of them. Existing state regulations for the classification of oil and gas NORM/TENORM for waste management and disposal purposes are provided in **Table 6.4**. It is important to note that many states do not draw a regulatory distinction between TENORM and NORM (Thompson et al., 2015). In an effort to promote uniform regulation of TENORM, the Conference of Radiation Control Program Directors has developed suggested state regulations for TENORM concentrations and dose thresholds in the oil and gas industry (Conference of Radiation Control Program Directors, 2004; Thompson et al., 2015) (see **Table 6.4**).

The International Commission on Radiological Protection (ICRP) has set dose limits for both public and worker exposures to NORM from oil and gas operations (ICRP, 2019). The ICRP reference dose level for protection of the public "should be selected of the order of a few mSv [millisievert] per year, or below" (ICRP, 2019). The ICRP reference dose for protection of workers is "of the order of a few mSv per year, or below, for most cases; and above a few mSv, but very rarely exceeding 10 mSv year^{-1}." Most of the dose thresholds in **Table 6.4** are hourly rates. Four states (Illinois, Maine, New Jersey, Virginia) have annual dose thresholds, and these are compliant with ICRP recommendations. For states that have hourly thresholds, it would be necessary to restrict exposure time to be ICRP compliant. For example, at 0.5 uSv/hr (microsieverts per hour), an annual dose of 1 mSv would accrue in 2,000 hours of exposure and at 0.02 mSv/hr, an annual dose of 1 mSv would accrue in 50 hours.

Dose limits for NORM and TENORM have been recommended by the ICRP and standards have also been established by several states as noted in **Table 6.4**, California currently has no mandatory monitoring program to confirm compliance with ICRP or California radiation protection standards and/or to confirm that California populations are not exposed to unacceptable risk from NORM and TENORM.

Table 6.4. Summary of regulations concerning NORM or TENORM thresholds for waste management and disposal. Source: Adapted from Thompson et al. (2015).

State or Organization	Concentration threshold for NORM/TENORM below which waste is exempt	Dose threshold for NORM/TENORM below which waste is exempt
Conference of Radiation Control Program Directors	0.185 Bq/g (5 pCi/g) of Ra-226 and/or Ra-228	0.5 µSv/hr (50 µR/hr) at any accessible point, including background
Alabama	0.185 Bq/g (5 pCi/g) of combined Ra-226 and Ra-228	0.5 µSv/hr (50 µR/hr) at contact with the NORM or NORM-contaminated article, including background
Arkansas	0.185 Bq/g (5 pCi/g) of Ra-226 and/or Ra-228, 0.05% by weight of uranium or thorium, or 5.55 Bq/g (150 pCi/g) of any other NORM radionuclide, provided that these concentrations are not exceeded at any time	0.5 µSv/hr (50 µR/hr) above background for equipment exposure level at any accessible point
Georgia	0.185 Bq/g (5 pCi/g) of technologically enhanced Ra-226 or Ra-228 in soil or other media, averaged over any 100 square meters (1,076 square feet) and averaged over the first 15 cm (6 in) of soil below the surface, in which the radon emanation rate is equal to or greater than 0.74 Bq (20 pCi) per square meter per second	0.02 mSv/hr (2 mrem/hr) 18 inches from the NORM contaminated material
Illinois	7.4 Bq/g (200 pCi/g) (dry weight basis) for sludges and water treatment residuals from the treatment of groundwater provided disposal is effected through one of two regulated pathways. Sludges beneath 0.111 Bq/g (3 pCi/g) (dry weight basis) are unregulated/not subject to exempt restrictions/requirements	0.10 mSv (10 mrem) per year above background exposure due to TENORM
Louisiana	0.185 Bq/g (5 pCi/g) of Ra-226 or Ra-228 above background or 5.55 Bq/g (150 pCi/g) of another NORM radionuclide	0.5 µSv/hr (50 µR/hr) above background for equipment exposure level
Maine	0.185 Bq/g (5 pCi/g) above background	1 mSv/yr (0.1 rem/yr) total effective dose for maximally exposed individual

State or Organization	Concentration threshold for NORM/TENORM below which waste is exempt	Dose threshold for NORM/TENORM below which waste is exempt
Mississippi	0.185 Bq/g (5 pCi/g) of Ra-226 or Ra-228 above background; or concentrations less than 1.11kBq/kg (30 pCi/g) of technologically enhanced Ra-226 or Ra-228, averaged over any 100 square meters (1,076 square feet), provided the radon emanation rate does not exceed 740 mBq (20 pCi) per square meter per second, or 5.55 kBq/kg (150 piCi/g) of any other NORM radionuclide, provided that these concentrations are not exceed at any time	0.25 µSv/hr (25 µR/hr) above background for equipment exposure level at any accessible point
Nevada[1]	0.555 Bq/g (15 pCi/g) Ra-226	-
New Jersey	37 kBq (0.1 microcurie)	0.15 mSv/yr (15 mrem/yr) total effective dose equivalent
New Mexico	1.11 Bq/g (30 pCi/g) or less of Ra226, above background, or 5.55Bq/g (150 pCi/g) or less of any other NORM radionuclide above background, in soil, in 15 cm (6 in) layers, averaged over 100 square meters (1,076 square feet).	0.5 µSv/hr (50 µR/hr) at any accessible point, including background
New York	Any NORM that is processed and concentrated is subject to regulation. TENORM from oil and gas production is not allowed for landfill disposal. (See 6NYCRR Part 380-1.2 (e) and 380-4.2.)	Note: High volume hydraulic fracturing for gas has been banned in the state of New York.
North Dakota[1]	0.185 Bq/g (5 pCi/g) total radium	-
Ohio	185 Bq/kg (5 pCi/g) above background	0.5 µSv/hr (50 µrem/hr) including background
Oregon	185 Bq/kg (5 pCi/g) of radium, 0.05% by weight of uranium or thorium or 5.55 kBq/kg (150 pCi/g) of any other NORM radionuclide provided that these concentrations are not exceeded at any time	Material that may be released to the general environment in groundwater, surface water, air, soil, plants, and animals shall not result in an annual dose above background exceeding an equivalent of 0.25 mSv (25 mrem) to the whole body or 0.75 mSv (75 mrem) to the critical organ of any member of the public

State or Organization	Concentration threshold for NORM/TENORM below which waste is exempt	Dose threshold for NORM/TENORM below which waste is exempt
Pennsylvania	No pre-approval required for TENORM waste disposal in RCRA D facilities if the combined radium activity is less than 0.185 Bq/g (5.0 pCi/g), and below 1 cubic meter in volume	-
South Carolina	1.11 Bq/g (30 pCi/g) or less of technologically enhanced natural radiation due to Ra-226 or Ra-228 in soil, averaged over any 100 square meters (1,076 square feet) and averaged over the first 15 cm (6 in) of soil below the surface, provided the radon emanation rate is less than 0.74 Bq (20 pCi) per square meter per second, OR 0.185 Bq/g (5 pCi/g) or less of technologically enhanced natural radiation due to Ra-226 or Ra-228 in soil, averaged over any 100 square meters (1,76 square feet) and averaged over the first 15 cm (6 in) of soil below the surface, in which the radon emanation rate is equal to or greater than 0.74 Bq/g (20 pCi) per square meter per second	0.5 µSv/hr (50 µR/hr) at any accessible point, including background
Tennessee[1]	1.11 Bq/g (30 pCi/g)	Contact dose rate 0.5 µSv/hr (50 µR/hr)
Texas[2]	1.11 Bq/g (30 pCi/g) or less of Ra-226 or Ra-228 and also contains 5.55 Bq/g (150 pCi) or less per gram of any other NORM radionuclide in soil, averaged over any 100 square meters (1,076 square feet) and averaged over the first 15 centimeters (6 in) of soil below the surface	0.02 mSv/hr (2 mrem/hr) at 18 inches from the NORM contaminated material
Utah[1]	0.555 Bq/g (15 pCi/g) Ra-226	-
Virginia	0.185 Bq/g, 185 Bq/kg (5 pCi/g) above background	1 mSv/y (100 mrem/y) total effective dose from TENORM for maximally exposed individual, excluding natural background

1. TENORM regulated as “Other Radioactive Material.”
2. Only applies to oil and gas TENORM.

Abbreviations: Bg - becquerel; mBg - megabecquerel; kBg - kilobecquerel; mSv - millisievert; mrem - millrem; NORM - naturally occurring radioactive materials; pCi - picocurie; TENORM - technologically enhanced naturally occurring radioactive material; µR - microroentgen; µrem - microrem; µSv - microsievert

6.4.1.1 Abandoned Pipelines and Infrastructure: PCBs

The presence of PCBs in pipelines is primarily a legacy issue. PCBs were used from the 1950s to the 1970s as components of working fluids in compressors, pipeline lubricants, fogging agents, and valve grease, and migrated throughout gas systems (American Gas Association, 2010; US EPA, 2004). PCBs were also used in certain gas pipeline coatings (e.g., coal tar) (American Gas Association, 2010; Con Edison, 2012). PCBs are environmentally persistent, known human carcinogens, and can adversely alter the immune system, nervous system, thyroid, and hormonal system, increasing the risk of infertility, heart disease, hypertension, diabetes, liver disease, and asthma (Carpenter, 2006; IARC, 2016). PCB contamination is a well-known hazard and action should be taken to remediate and/or manage PCBs during pipeline abatement. Priority for PCB management on pipeline abatement should be granted to those sections of pipe/areas with the highest potential for introducing PCBs along exposure pathways to humans (e.g., through soil, water) and sections where PCBs may accumulate.

Gas pipelines with PCB concentrations ≥50 parts per million (ppm) are regulated under 40 C.F.R. § 761.60 (b)(5) of the Toxic Substances Control Act (TSCA), and can be abandoned in place if certain provisions are met (40 C.F.R. § 761.60, 1979). An overview of TSCA regulations regarding in place abandonment of PCB contaminated pipelines is provided in **Table 6.5**.

In the absence of excavation and disposal, an assumption should be made that pipelines will corrode and PCBs will be incorporated into soil. PCBs would be expected to be present in scale and sludge in pipelines. The U.S. EPA has developed methods for determining remediation criteria for contaminated soils, which are applicable to California. CalGEM has an opportunity to use the U.S. EPA remediation criteria to estimate concentrations of PCB in scale or the lining of pipes that could result in a soil contaminated at an unacceptable level.

6.4.1.2 Abandoned Pipelines and Infrastructure: Asbestos

Prior to 1980, asbestos was used in oil and gas infrastructure as a component of gaskets, sealants, and in pipeline coatings (e.g., coal tar enamel or asphaltic enamel pipe wrap) to protect from corrosion and the elements (Con Edison, 2012; Howell, 2011; US EPA, 2019). Exposure to asbestos from buried pipelines may occur due to overlying development and excavation, or from erosion and other hazards that expose friable pipeline coatings to the environment. Inhalation of asbestos can negatively impact lung function, increase the risk of lung cancer and mesothelioma, and is a documented health concern in oil refinery workers (ATSDR, 2016; Gennaro et al., 2000).

Pipeline wrap that contains more than 1% asbestos and that can be crumbled, pulverized, or reduced to powder by hand pressure when dry is considered friable and is a regulated asbestos-containing material (RACM) that requires specific training and procedures for safe excavation and disposal (40 C.F.R. § 61.141, 1995). Asbestos-containing materials that may become friable during sanding, grinding, cutting, or abrading, or during demolition or renovation are also RACM (40 C.F.R. § 61.141, 1995). Intact pipeline wrap that is in good condition and nonfriable generally retains asbestos fibers within the coal tar or asphaltic matrix and is not considered a RACM (American Gas Association, 2006; BP U.S. Pipelines and Logistics, 2019). These materials can be manually removed with hand tools that shear or slice with minimal protective measures (BP U.S. Pipelines and Logistics, 2019).

To the best of our knowledge, there is no public database of pipelines, flowlines, gathering lines, or other oil and gas infrastructure that may contain asbestos. Thus, the extent of asbestos use in legacy oil and gas pipelines and infrastructure in California is unknown. However, Southern California Gas and San Diego Gas & Electric, two major gas utilities in California, have compiled historical construction records and estimate that they operate a combined 1,850 km (1,150 miles) of transmission pipelines that use coal tar pipeline wrap and may contain asbestos (Southern California Gas Company & San Diego Gas & Electric, 2016). Although there is significant uncertainty about the presence of asbestos in California pipelines, the pipeline records of these two utilities suggest that asbestos-containing pipeline wraps are a potential concern that should be considered in pipeline excavation and disposal.

6.4.1.3 Incidents from Abandoned Pipelines

Regulations regarding pipeline abandonment require pipelines to be purged of oil or combustibles prior to abandonment. Despite existing regulations, improperly abandoned pipelines have negatively impacted surrounding communities. Two incidents of oil leaking from improperly abandoned underground pipelines in California were documented by the DOT Pipeline and Hazardous Materials Safety Administration (PHMSA) (PHMSA, 2016). On March 17, 2014, a leaking abandoned pipeline in Wilmington released between 36 to 71 barrels (bbl) (5,670 to 11,360 L; 1,498 to 3,001 gallons) of crude oil into a residential community, leading to numerous complaints of foul odors. The leak originated from internal pinhole corrosion on a weld. On October 28, 2015, an abandoned pipeline leaked approximately 28 bbl (4,450 L; 1,176 gallons) of oil-water mixture onto a busy intersection in Cypress. In both cases, the owners of the pipelines at the time were under the impression that the pipelines were properly purged and abandoned by the previous owners at the time of purchase (PHMSA, 2016).

In 2017 in Firestone, Colorado, improperly abandoned gas pipelines were responsible for leaking gas into a home, causing an explosion which killed two and injured two others (National Transportation Safety Board, 2019). Colorado regulations at the time required abandoned pipelines to be disconnected from hydrocarbon sources, purged, depleted to atmospheric pressure, and sealed.

6.4.2. Pipeline Abandonment Regulations

Although interstate pipelines for distribution of oil, gas, and petroleum products are downstream from oil and gas production, the regulation of abandoned downstream pipelines offers insight on the regulation of abandoned upstream pipelines. To gain insight for abandoned pipelines in California oil and gas production we provide in this section a review of U.S. federal regulations that apply to abandoned interstate pipelines, as well as abandoned pipeline regulations in Colorado and Canada.

Interstate pipelines are regulated at the federal level by PHMSA. Under 49 C.F.R. Part 195.402(c) and 192.727(b), pipelines abandoned in-place must be disconnected from operating pipeline systems, purged of combustibles, and sealed prior to abandonment. PHMSA does not recognize an idle, inactive, or decommissioned status for pipelines; pipelines are considered either active and subject to all safety regulations, or abandoned (PHMSA, 2016).

Abandonment of pipelines and flowlines on Bureau of Land Management-managed land requires flushing and disposal of any fluids and removal of any surface lines or shallow lines that may be exposed due to wind or water erosion (US Department of the Interior & US Department of Agriculture, 2007). Deeply buried pipelines and flowlines can be abandoned in-place.

In California, CalGEM regulates oil and gas production equipment, including pipelines, from the wellhead to the sales meter. Downstream, the Office of the State Fire Marshal Pipeline Safety Division has authority to enforce federal and state regulations for intrastate hazardous liquid pipelines; intrastate gas and liquid petroleum gas pipelines are regulated by the California Public Utilities Commission. Under 14 C.C.R. § 1776, well site and lease restoration requires operators to submit a lease restoration plan prior to the plugging and abandonment of the last well on a lease (14 C.C.R. § 1776, 2006). Lease restoration requires the removal of all tanks, above-ground pipelines, debris, and other facilities and equipment. Remaining buried pipelines must be purged of oil and filled with an inert fluid. Lease restoration must be completed within one year of plugging and abandonment of the last well.

The handling and disposal of gas pipelines with PCB concentrations ≥50 ppm are regulated under U.S. EPA TSCA (40 C.F.R. § 761.60, 1979). These pipelines can be removed with subsequent disposal to a licensed facility, or they can be abandoned in-place under the provisions summarized in **Table 6.5**.

Table 6.5. Summary of provisions for in-place abandonment of gas pipeline systems containing PCBs ≥50 ppm under EPA TSCA (40 C.F.R. § 761.60(b)(5)).

Inside diameter requirement	Free-flowing liquids	PCBs requirement	Sealing requirement	Other requirements
≤4 inches	No free-flowing liquids	PCBs of any concentration	Each end is sealed closed	● Include pipeline in public service notification program. ● Pipe filled to 50% volume or more with grout or polyurethane foam.
Any	No free-flowing liquids	PCB concentration determined after last transmission or at time of abandonment	Each end is sealed closed	-
Any	No free-flowing liquids	PCBs of any concentration	Each end is sealed closed	● Interior surface decontaminated using solvent washes. Must recover 95% of solvent volume. Recovered solvent PCB concentration must be <50 ppm. ● Pipe filled to 50% volume or more with grout or polyurethane foam.

Inside diameter requirement	Free-flowing liquids	PCBs requirement	Sealing requirement	Other requirements
Any	-	PCBs of any concentration	-	● Drain and dispose of free-flowing liquids. ● Decontamination of surfaces using either kerosene, diesel fuel, terpene hydrocarbons, or terpene hydrocarbon/terpene alcohol mix. ● Multiple decontamination treatments required if PCB concentration in free-flowing liquid is >10,000 ppm.
				• Submit an alternate decontamination plan to EPA regional administrator.

Pipeline Abandonment Regulations in Other Regions

In Colorado, flowlines (defined as any pipe segment that transfers oil, gas, condensate, or produced water between a wellhead and processing equipment) and crude oil transfer lines can be abandoned in place by physically separating them from sources of fluids or pressure, purging any liquids, depressurizing, sealing the ends below grade, cutting risers to the depth of the flowline, and removing above ground cathodic protection and equipment (2 Colo. Code Reg. § 404-1-1105, 2020).

Canadian regulations surrounding pipeline abandonment vary according to province, but generally require pipelines to be purged with water or an inert gas, cleaned, and plugged or capped (Crosby et al., 2015). Cleaning techniques typically consist of some combination of pigging and chemical cleaning operations; however, questions remain regarding how clean is considered clean (Crosby et al., 2015).

6.4.2.1 Framework for Pipeline and Infrastructure Abandonment

The Petroleum Technology Alliance of Canada, the Canadian Energy Pipeline Association, Canada's National Energy Board, the Canadian Association of Petroleum Producers, and other stakeholders have collaborated on the Pipeline Abandonment Research Program to develop guidelines for pipeline cleaning prior to abandonment (Crosby et al., 2015) and a risk-based decision-making framework for pipeline abandonment (Arcadis Canada, 2019). This decision-making framework evaluates six categories of physical and technical hazards related to pipeline abandonment (Arcadis Canada, 2019):

1. Chemical impacts to soil or groundwater from former operations (i.e., existing contamination at the site).
2. Environmental impacts from pipeline materials abandoned in place.
    a. Residual products, lubricants, treatment chemicals (including NORM and PCBs).
    b. Leaching of construction materials and coatings.

   c. Presence and exposure of asbestos.
3. Drainage of surface water or groundwater through pipeline.
4. Ground subsidence.
5. Exposure of pipeline due to erosion and geohazards.
6. Exposure of pipeline due to hydrotechnical hazards.

This framework may act as a basis for developing a similar scientifically defensible risk-based decision-making pipeline abandonment framework in California.

6.5. Discussion

6.5.1. Lack of Data Collection Relevant to Assessing Health and Safety Risks

Several studies suggest that CalGEM undercounts the number of abandoned wells, particularly legacy abandoned wells with incomplete or undigitized historical records. These unrecorded wells tend to be old, unplugged wells or improperly plugged abandoned wells. Similarly, records are not always maintained for abandoned and legacy pipelines and operators are not required to report abandoned, removed, idle-deserted, or deserted pipelines in pipeline management plans.

Because idle production wells must be non-producing for a 24-month period, there is an inherent lag between when production stops and a well is categorized as idle. Thus, the true number of wells that not producing at any given time are likely under-represented in CalGEM's "All Wells" dataset. Long-term idle wells were not differentiated from other idle wells in the "All Wells" dataset. Other means of determining the number of long-term idle wells, or wells that may become idle in the future, require analyzing production data on an individual-well basis over periods of years. This information is available and included in required legislative reporting, but collecting and organizing it is labor intensive. Although CalGEM has made progress identifying and disclosing idle-deserted wells, there remains a large backlog of deserted wells that may potentially be idle-deserted and need to be evaluated. At a minimum, accurate location and count data for abandoned, idle-deserted, and idle wells and associated infrastructure are required for proper epidemiological studies and risk assessments.

Studies of emissions from idle and abandoned wells in California primarily focus on methane, and even these studies are sparse in California. Additional measurements of methane emissions from abandoned (plugged and unplugged) wells are needed with a large sample set and a random sample selection, designing the study to determine whether parameters such as well status, geography, geology, or age of well explain some of the variability in the emission rates. Studies of VOC and TAC emissions from idle and abandoned wells in California are limited in scope and geographic coverage and are insufficient to characterize emission trends on a broader level. However, studies in other states have found that VOCs and TACs are co-emitted with methane from upstream oil and gas wells. Additional emissions monitoring, such as that required under AB 1328, and public disclosure of the composition of VOCs and TACs from idle and abandoned wells in California are needed to assess air pollution health risks and better inform policy makers.

6.5.2. Locations of Idle and Abandoned Wells and Safety Concerns in Densely Populated Areas

Idle wells are generally located in many of the same areas as active wells and are capable of returning to active status after production or injection for a period of six months. Likewise, active wells may become idle after no production or injection for a period of 24 months. There is strong evidence that proximity to active wells is linked to a variety of adverse health outcomes (see Chapter 3); however, only two studies in California examined proximity to idle wells, one of which observed a positive relationship between lung function and distance from both active and idle wells out to 1 km (3,281 ft). According to the proximity analysis in Chapter 7, approximately 3 million people live within 1 km (3,281 ft) of an “active-producing” well in California. Abandoned wells are generally more dispersed throughout the state compared to active and idle wells, and it is unclear how many people in California live within a given proximity of an abandoned well. At some point in the future, all current active and idle wells will become abandoned wells, at which point the number of people living within 1 km (3,281 ft) of an abandoned well could easily exceed 3 million. The available environmental public health literature is insufficient to draw conclusions about proximity to abandoned wells and legacy oil and gas infrastructure as a risk factor for adverse health outcomes. Additional epidemiological studies that take into account idle and abandoned wells would increase the understanding of underlying exposure sources and pathways as well as elucidate which types of wells may be of the greatest concern with regard to human health outcomes (Tran et al., 2020). This data could then be used to inform future regulatory decisions regarding the prioritization of monitoring, inspection, and plugging and abandoning to reduce community exposure from various types of wells.

Building on or near abandoned wells, particularly legacy abandoned wells, or improperly abandoned pipelines may present serious explosive hazards and health risks to residents in densely populated areas (Chilingar & Endres, 2005). Studies of emissions from upstream oil and gas development in California have documented methane emissions from abandoned wells (Lebel et al., 2020). In urban and residential areas, methane from nearby or underlying sources can migrate and accumulate in confined spaces, becoming an explosion and fire hazard. Multiple instances of gas seepage from both natural faults and abandoned wells have been documented in the Los Angeles area, where residential and commercial development have occurred directly over oil fields and old legacy abandoned wells (Chilingar & Endres, 2005). Since the Ross Dress for Less explosion in 1985, which was possibly linked to leaking gas accumulation, none of the documented cases have resulted in explosions. However, they have resulted in homes being torn down to access and re-abandon leaking wells, or commercial businesses installing gas detection and ventilation systems to mitigate the risk of explosions (Chilingar & Endres, 2005). Potential health impacts from contaminants associated with abandoned pipelines and other legacy infrastructure, including TENORM, PCBs, and asbestos, also need to be considered for future land use and development. As commercial and residential development expands into areas that may have previously been used for oil and gas development, there is a clear need to mitigate the risk of explosions and exposure to VOCs, TACs, TENORM, PCBs, and other potential contaminants through better record keeping, disclosure of locations, and studies of potential health impacts associated with legacy abandoned wells, as well as long-term monitoring of emissions and integrity of abandoned wells.

6.5.3. Economic Issues Associated with Idle, Idle-deserted, and Legacy Abandoned Wells

Economic issues and limited funding availability often result in idle-deserted and improperly abandoned legacy wells remaining unplugged for extended periods of time, during which nearby communities have been negatively impacted through leaking oil and the emission of VOCs and noxious odors (California State Lands Commission, 2017; CalGEM, 2016; SCAQMD, 2016).

If oil prices fall, operators are at increased risk of bankruptcy and wells becoming idle-deserted (CCST, 2018; Kang et al., 2021; Williams-Derry, 2020). For smaller operators that are more vulnerable to bankruptcy (and more likely to desert wells), and for wells that change ownership numerous times during their operational lifetimes, determining financial liability and recovering costs for plugging and abandoning may not always be straightforward or feasible (CCST, 2018; Western Organization of Resource Councils, 2021). When wells become idle-deserted, the state becomes liable for any costs associated with plugging and abandonment. Costs of plugging wells in some areas can exceed $1 million per well (California State Lands Commission, 2020; Grilley & Welch, 2020), and studies have estimated California's total liability for plugging and abandoning idle-deserted wells to range from tens to hundreds of millions of dollars after bonding requirements were taken into account (CCST, 2018; Nelson & Fisk, 2021). Current funding appropriations for plugging and abandoning idle-deserted wells is $3 million per year until fiscal year 2022–2023, when it will decrease to $1 million (Department of Conservation, 2020). Based on estimated costs and appropriations, CalGEM estimates that seven to 33 idle-deserted wells will be plugged and abandoned annually, starting in fiscal year 2022-2023. Recent updates to idle well regulations have increased both testing requirements and incentives for operators to plug and abandon idle wells. As more idle wells are plugged and abandoned, the potential liability to the State is reduced. As of 2019, CalGEM identified 24 idle-deserted wells and another 3,265 deserted or potentially deserted wells that need to be evaluated.

The large number of potentially idle-deserted and improperly abandoned wells, their potential impacts to surrounding communities, the costs associated with proper plugging and abandonment, and limited funding availability could increase concerns about the existence of these wells.

6.6. Summary

California has a long history of oil and gas production and there are numerous abandoned wells and associated legacy infrastructure located in oil and gas basins throughout the state. CalGEM reports approximately 126,000 plugged and abandoned oil and gas wells in California, although recent studies suggest that the number of abandoned wells may be underreported by 17% or more. There are also an estimated 2,500–5,000 idle-deserted wells in which responsibility to plug and abandon falls to the state. The number of abandoned oil and gas wells is only expected to increase as individual well production eventually decreases to the point where operation is no longer economically viable. At some point in the future, all current active and idle wells will become abandoned wells, at which point the number of people living within 1 km (3,281 ft) of an abandoned well could easily exceed 3 million. Less is known about the abundance of abandoned pipelines and other legacy infrastructure due to inadequate documentation. Idle, abandoned, removed, idle-deserted, and deserted pipelines are not considered active and thus are not required to be reported by operators in pipeline management plans submitted to CalGEM. Information on abandoned legacy infrastructure will depend on requirements from other regulatory agencies or datasets.

Abandoned oil and gas wells, pipelines, and other legacy infrastructure pose multiple concerns for public health through both surface and subsurface pathways, including the release of oil, gas, produced water, radioactive scale (i.e., TENORM), and legacy pipeline treatment chemicals (PCBs, etc). Corrosion and weathering may also release heavy metals from pipeline bodies and welds, and hazardous materials used in pipeline coatings such as asbestos.

Current non-methane hydrocarbons (NMHC) and TAC emissions data from abandoned, inactive, and idle wells are inadequate to reliably assess the potential impacts on human health. The majority of studies of emissions from idle and abandoned wells in California focus on methane and studies that have measured NMHC and TAC emissions are limited in scope and geographic coverage. Studies of methane emissions from abandoned and idle wells in California have found that most emissions come from a small number of wells that are "super-emitters." Additionally, failures in abandoned well integrity that result in emissions or contamination of water resources may go undetected for extended periods. Despite this, there are no long-term monitoring requirements for abandoned wells. Assembly Bill 1328 (2019) calls for CalGEM and CARB to initiate a study of greenhouse gas, TAC, and VOC emissions from idle and abandoned wells with cooperation from oil and gas operators; however, the results from this study are yet to be released at the time of writing this report.

Available epidemiological literature related to idle, inactive, and abandoned wells is limited. A single study found that living nearby and downwind of oil and gas development sites, active or idle, was associated with reduced lung function among residents. However, others did not find any association with proximity to idle wells and adverse health outcomes. Overall, the available environmental public health literature is insufficient to draw conclusions about proximity to inactive wells, abandoned wells, and other legacy oil and gas infrastructure as a risk factor for adverse health outcomes.

Key information regarding the number and location of abandoned pipeline and other legacy infrastructure, and the characterization of the extent of potential hazards such as PCB and TENORM contamination, is needed before health risks can be assessed. Current regulations for the handling and management of oil and gas related NORM/TENORM in California are lacking. In recent years, improperly abandoned legacy pipelines in California have resulted in events that released crude oil and oil-water mixtures to the surface, potentially exposing nearby communities to hazards. A risk-based decision-making framework for in-place pipeline abandonment, similar to the one developed by Canada, would help mitigate potential issues with groundwater resource contamination, future land use, and potential hazards such as PCBs, TENORM, and asbestos.

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CHAPTER SEVEN

Proximity Analysis of Oil and Gas Development and Human Populations in California

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7.0. Abstract

The peer-reviewed literature is sufficiently clear that oil and gas development (OGD) immediately adjacent to places where people live, work, play, and learn poses hazards and risks to public health. California has maintained one of the least stringent land zoning regulations (i.e., setbacks) in the United States. Consequently, a significant proportion of California residents currently live in proximity to OGD, with distinct racial and socioeconomic inequities whereby disadvantaged communities are much more likely to be located near OGD.

Specifically, an estimated 3 million, or approximately 1 in 12 (~8%) California residents live within 1 km (3,281 ft) of active oil and gas development (OGD). Within these populations, non-Hispanic Black Californians disproportionately live near active OGD, and are nearly 50% more likely to have at least one active well within 1 km (3,281 ft) of their residence as compared to the average Californian. Furthermore, non-Hispanic Black Californians are 87% more likely to have at least one active well within 1 km (3,281 ft) of their residence when compared to non-Hispanic White populations alone. Distance-based disparities also exist for low income, linguistically isolated households, renters, and low educational attainment. Although active-producing wells and locations of wastewater disposal infrastructure (e.g., disposal ponds and injection wells) share about 70% of observed land-uses, demographic analyses indicate that wastewater facilities do not completely mimic population-level inequities observed for active OGD. This discrepancy suggests that different populations across California may be disproportionately burdened by various sub-sectors of the oil and gas supply chain. Overall, populations living near OGD stand to benefit the most from any proximity-based legislation that addresses the public health and safety burdens faced by these communities.

The weight of the scientific evidence indicates that the risk of numerous adverse health outcomes (e.g., adverse birth outcomes, respiratory outcomes) increases with higher oil and gas well density and hydrocarbon production volume. Given typical spatial clustering of oil and gas wells, many Californians that live in proximity to one well likely live in proximity to many wells. Overall, we found that 157 census tracts in 16 areas have a well density of at least 10 wells/km^2 encompassing more than 628,000 Californians. Sixty-four of these 157 census tracts (~40%) have CalEnviroScreen 3.0 (OEHHA, 2018), scores designating them as disadvantaged communities, with disproportionate socioeconomic, health, and environmental burdens, in addition to the burdens associated with upstream oil and gas development. Because a quarter of all California census tracts are designated as disadvantaged communities based on CalEnviroScreen scores, this finding indicates that disadvantaged communities are overrepresented (1.6 times more likely) in census tracts that contain 10 or more wells per square kilometer. The highest mean well density was observed in the Los Angeles cluster location, where an area just over 5 mi^2 (13 km^2) contains 866 active-producing wells.

An estimated 1,749 (~8%) pre-K through 12th grade schools are within 1 km (3,281 ft) of at least one active-producing well, and 1,014 of these schools (58%) are within 1 km (3,281 ft) of multiple wells. Specifically, 107 schools are within 1 km (3,281 ft) of at least 100 wells and 33 schools have over 300 wells within a 1 km (3,281 ft) radius. Notably, a relatively small proportion of total OGD wells in California (2-7% depending on receptor) have a school, childcare facility, healthcare

facility, senior care facility, correctional facility, or park within 1 km (3,281 ft) (with the exception of residential buildings). For example, 2,377 out of 83,834 (roughly 1 in 35) wells are within 1 km (3,281 ft) of a healthcare facility. This represents just 3% of the total well inventory, with nearly 97% of wells beyond 1 km (3,281 ft) of any California healthcare facility. These findings suggest that nearly all co-locations between OGD and schools, childcare facilities, healthcare facilities, senior-care facilities, correctional facilities, and parks could be eliminated by shutting in less than 7% of California's total active-producing well inventory. However, over 30,000 (36%) of active-producing wells are located within 1 km (3,281 ft) of residential buildings indicating a more distributed overlap between OGD and Californian residents.

To mitigate health risks associated with upstream oil and gas development, California should implement a health-protective, minimum surface setback distance between upstream oil and gas development and human populations. Decision-making regarding the appropriate health-protective minimum surface setback distance should (1) consider multiple stressors associated with upstream oil and gas activities, (2) include an additional margin of safety to account for the vulnerabilities of population subgroups, and (3) take into account existing environmental and socioeconomic burdens experienced by communities that may enhance vulnerability to the adverse health effects of oil and gas development activities. Because exemptions and conditional exceptions for minimum surface setback requirements will likely diminish health protections for communities and other sensitive receptors, such exemptions and exceptions should be avoided. Finally, given the significant proportion of California residents currently living in proximity to OGD, the state of California should deploy measures to reduce impacts associated with existing upstream oil and gas development.

7.1. Purpose

The purpose of this analysis is to characterize human populations in proximity to existing oil and gas activities throughout the state of California. This analysis is framed within a public health context that considers the potential human health risks associated with upstream, oil and gas development (OGD) in California in tandem with population-level susceptibilities and socio-economic inequities. Here we use the term "land use co-location" to describe any occurrences where OGD is located within close proximity to human populations.

Given the findings and conclusions presented in earlier chapters and the importance of proximity and public health therein, this California proximity analysis includes multiple sections that address various aspects of setback regulations and related well location restriction policies. We first report on the state of setback policies in other major oil and gas producing states. We then discuss California's well location restrictions and setback policies that exist for certain jurisdictions within California. To inform future rulemaking recommendations, we compare these policies to other states, and discuss the precedence that has been set by these policies in terms of risk management. We also provide context related to general setback rulemaking and definitions and discuss the emerging understanding related to exemptions and exceptions and their potential to attenuate the effectiveness of setback policies in practice. Finally, we examine whether specific racially or socioeconomically marginalized people in California are more likely to reside near active oil and gas wells.

7.1.1. Proximity analysis and public health

A proximity analysis is a type of analysis that anchors data to distinct locations or land areas to better understand the spatial relationship(s) between those entities of interest. Within an environmental public health context, a spatial proximity analysis is typically designed to characterize the spatial relationship(s) between a known or suspected set of source-hazards and a set of receptors, such as human populations that may be at risk to exposure from those hazards. This type of source-receptor study design is commonly used in environmental public health research to examine population-level health risks from hazards that are known to adversely impact health given certain exposure conditions. Identifying affected populations that may be exposed to a known risk factor can be considered a type of health impact analysis, which is often used to evaluate public health consequences of proposed decisions, interventions, or policy changes. A proximity analysis also facilitates an environmental justice assessment by assessing relative burdens to population sub-groups. “Identifying populations” is one of the five steps outlined in the SB 1000 (the Planning for Healthy Communities Act) Implementation Toolkit developed by the California Environmental Justice Alliance when performing a vulnerability assessment towards reducing unique or compounding health risks in disadvantaged communities (CEJA and PlaceWorks, 2017).

This proximity analysis provides:

1. Tangible metrics that contextualize the associated public health and safety burdens faced by communities living in proximity to OGD.
2. A comparison of spatial relationships to inform minimum surface setback regulations, and identify the associated populations benefitted by various setback distances.
3. An inequity assessment to determine if disadvantaged communities are more likely to be located in proximity to OGD in California.
4. Information regarding how close some homes and residents are to OGD.

Results of these analyses are discussed in terms of public-health-protective policies. Narrative discussions focus on both instances where health impacts may be greatest (e.g., population counts at the shortest distances) and where policy and mitigation efforts may be most protective (e.g., population counts at the greatest distances).

To characterize human populations in proximity to existing OGD throughout California, we used population and sociodemographic data resolved at the sub-census block level — representing the most spatially precise estimates to date. We present OGD in proximity to key sensitive receptors, such as schools and health care facilities, resolved at the building footprint and area extent resolutions. Finally, by using both the discrete locations of oil and gas wells and more than 10 million individual building footprints, we also show just how close some California residents live near active oil and gas wells. Overall, this proximity analysis employs a high degree of spatial resolution to accurately characterize OGD and the immediately adjacent places where people live, work, play, and learn.

7.2. Background and Justification

As detailed in Chapters 2, 3, and 4, proximity to upstream OGD is a well-established public health risk factor in the peer-reviewed literature. From Chapter 3, public health risks and impacts increase with close proximity to oil and gas development. Chapter 4 further elucidates the importance of distance to explain differences in findings related to physical hazards, air monitoring/modeling studies, exposure assessments, and risks assessments. In sum, the public health risk factors associated with upstream OGD identified in the peer-reviewed literature include, but are not limited to, residential proximity to upstream oil and gas well sites, well density, and production volumes.

The identification of these multiple risk factors and adverse health effect findings observed in the peer-reviewed literature further support mitigation policies, such as minimum surface setback distances, to reduce public health risks and impacts. Setbacks are intended to reduce proximal population exposures to localized stressors such as toxic air contaminants, noise, and physical hazards associated with OGD by attenuating the exposure pathways that may be responsible for the observed human health risks and reported impacts in the peer-reviewed literature.

7.2.1. Review of surface setback regulations in the U.S.

Setbacks are land-zoning regulations intended to delineate a development-free or exclusion zone of land. Setbacks in some of the top producing states are summarized in **Table 7.1**. An estimated 20 of the 31 states with oil and gas development have some form of well setback restrictions from buildings (NCSL, 2021; Richardson et al., 2013). Many states, municipalities, and local governments have recently sought greater setback distances following rapid development in unconventional shale plays, particularly in increasingly urbanized areas. For example, following substantial growth in unconventional natural gas development in Pennsylvania, in 2012 the Pennsylvania General Assembly enacted the Pennsylvania Oil and Gas Act (58 Pa. Cons. Stat. § 3215, 2016) requiring (among other things) a more stringent setback from buildings, increasing from 200 to 500 ft (61 to 152 m) for unconventional wells. Similarly, in 2016, Maryland adopted a 1,000 ft (305 m) setback from any "school, church, drinking water supply, wellhead protection area, or an occupied dwelling" (Md. Code Regs. § 26.19.01.09, 2020). And despite a broad statewide setback preemption law in Texas, municipalities in Texas have been able to independently impose "commercially reasonable" setbacks (Tex. H.B. No. 40, 2015). Most recently, in 2020 the state of Colorado passed a 2,000 ft (610 m) setback from the "working pad surface" for residential buildings, high occupancy buildings, schools, and childcare centers. The exemption language for each building type includes additional informed consent, which requires consent from both building owners and tenants, as well as providing information in the languages used by populations living within the setback distances (COGCC Rules 600 Series, 2021). See **Table 7.1** for a fuller list of state and substate well location restriction regulations across the United States.

7.2.2. Existing well location restrictions and surface setback regulations in California

The state of California maintains regulations related to both well location restrictions and conditional performance standards based upon well location and nearby entities (14 Cal. Code Regs. § 1720; 24 Cal. Code Regs. § 5706.3). However, at the time of writing this report, as per Article 6, Preemption (Cal. Pub. Res. Code § 3690, 1971), California does not preempt any related land use zoning or well siting regulations and defers to political subdivisions. Thus, some political subdivisions have setbacks within their respective jurisdictions. At the time of writing this report, three cities and three counties within California have enacted setback regulations related to oil and gas activity, as shown in **Table 7.2**. Setback distances range from 50 to 2,500 ft (15 to 762 m), with distances based on the nature of the receptor. For example, places where more susceptible populations are likely present, such as schools and hospitals, have more stringent setback requirements.

Table 7.1. Summary of minimum surface setback distances from oil and gas development in the United States.

State	Jurisdiction	Year Adopted/ Amended	Setback Distance (ft)	Setback Target	Source
CO	State	2020	2,000 (610 m) (working pad surface boundary)	School facility or childcare center; residential building units and high occupancy building units	COGCC Rules 600 Series (2021)
IL	State	2013	500 (152 m) (UNGD[a])	Residence, school, hospital, nursing home, water well	Ill. Senate Bill No. 1715 (2013)
			1500 (457 m) (UNGD)	Ground water intake of a public water supply	
MD	State	2016	1,000 (305 m)	Housing, schools, faith institutions	LACDPH (2018)
			2,000 (610 m)	Private drinking water wells	
ND	State	2013	500 (152 m)	Occupied dwelling/structure	N.D. Cent. Code § 38-08-05
NM	Santa Fe County	2008	750 (229 m)	Housing, schools	LACDPH (2018)
			1,000 (305 m)	Groundwater and surface water resources	
OK	Oklahoma City	2015	300 (91 m)	Housing, fresh water well	LACDPH (2018)
			600 (183 m)	Faith institutions	
PA	State	2012	500 (152 m) (UNGD)	Housing and commercial buildings	58 Pa. Cons. Stat. § 3215 (2016), Haley et al. (2016)
	State	2012	200 (61 m) (CNGD[b])	Housing and commercial buildings	58 Pa. Cons. Stat. § 3215 (2016)

State	Jurisdiction	Year Adopted/ Amended	Setback Distance (ft)	Setback Target	Source
	State	2012	1,000 (305 m) (UNGD)	Water well; drinking water intake	58 Pa. Cons. Stat. § 3215 (2016)
	State	2012	750 (229 m) (Chemical storage)	Body of water	58 Pa. Cons. Stat. § 3215 (2016)
TX	City of Arlington	2011	200 (61 m)	Fresh water well	LACDPH (2018)
			600 (189 m)	Housing, schools, faith institutions, hospitals	
	City of Dallas	2013	1,500 (457 m)	Housing, schools, faith institutions	LACDPH (2018)
	City of Flower Mound	2011	1,500 (457 m)	Housing, schools, faith institutions, hospitals, existing water wells	LACDPH (2018)
	City of Fort Worth	2010	200 (61 m)	Fresh water well	LACDPH (2018)
			600 (189 m)	Housing, schools, faith institutions, hospitals	
WV	State	2012	200 (61 m) (CNGD)	Existing water well or dwelling	W. Va. Code § 22-6-21
			625 (191 m) (UNGD, center of well pad)	Occupied dwelling structure; building 2,500 sq. ft. or larger used to house or shelter dairy cattle or poultry husbandry	W. Va. Code § 22-6A-12
			250 (76 m) (UNGD)	Existing water well or developed spring	
			100 (30 m) (UNGD)	Perennial stream, natural or artificial lake, pond or reservoir, wetland	
			300 (91 m) (UNGD)	Naturally reproducing trout stream	
			1000 (305 m) (UNGD)	Surface or groundwater intake of a public water supply	

Table 7.2. California and sub-state level well location restrictions and minimum surface setback regulations.

Jurisdiction	Year Adopted	Setback Distance (ft)	Setback Receptors	Source
State of California	1975	100 (30 m)	Well deemed a “critical well” as one within 100 ft of a dedicated public street, highway, or operating railway; any navigable body of water; any public recreational facility, or any other area of periodic high-density population; or any officially recognized wildlife preserve	14 Cal. Code Regs. § 1724.3
		300 (91 m)	Well deemed a “critical well” if within 300 ft of a residence or airport runway	
State of California (Fire Code)	2011	100 (30 m)	Wells shall not be within 100 ft of buildings not necessary to the operation of the well	24 Cal. Code Regs. § 5706.3
		300 (91 m)	Wells shall not be drilled within 300 feet of building with an occupancy in Group A, E, or I (see definitions below)	
City of Arvin	2018	300 (91 m)	“Property boundaries of any public school, public park, clinic, hospital, long-term health care facility”; “property boundaries of any residence or residential zone” *[relevant to new development]*	Arvin, Cal. Code Ord. § 17.46.022 (2018)
		600 (183 m)	Sensitive sites such as parks, schools and hospitals *[relevant to new drilling]*	
City of Carson	2015	750 (229 m)	“property boundaries of any public school, public park, clinic, hospital, long-term health care facility”; “property boundaries of any residence or residential zone...”; property boundaries of the commercially designated zone”	Carson, Cal. Muni. Code § 9521 (2015)
		50 (15 m)	“any dedicated public street, highway, public walkway, or nearest rail of a railway being used as such”	

Jurisdiction	Year Adopted	Setback Distance (ft)	Setback Receptors	Source
City of Los Angeles	2011	200 (61 m)	School, hospital, sanitarium, or assembly occupancy	Los Angeles, Cal. Muni. Code § 91.6105 (2019)
		50 (15 m)	Building (>400 ft^2 area, 36 ft tall)	
Los Angeles County	2013	100 (30 m)	Building not necessary to the operation of a well	Los Angeles Co., Cal. Code Ord. tit. 32 (2021)
		300 (91 m)	Place of assembly, institution, or school	
Kern County	2015	210 (64 m)	Single or multi-family dwelling unit, place of public assembly, institution, school or hospital	KCPNRD (2016)
		100 (30 m)	"Any public Major or Secondary highway or building not necessary to the operation of the well"; "any building utilized for commercial purposes, not used for oil and gas operations"	
Ventura County	2020	1,500 (457 m)	"Residential dwellings"	Ventura County (2020)
		2,500 (762 m)	"Any school"	

[a]UNGD = unconventional natural gas drilling
[b]CNGD = conventional natural gas drilling

While not a wellhead location restriction, according to 14 Cal. Code Regs. (C.C.R.) § 1720, the state defines a "critical well" as one within 300 ft (91 m) of a residence or airport runway or within 100 ft (30 m) of a dedicated public street, highway, or operating railway; any navigable body of water; any public recreational facility, or any other area of periodic high-density population; or any officially recognized wildlife preserve. The California Geologic Energy Management Division (CalGEM) requires operators to disclose if a proposed well for drilling meets the definition of a critical well when applying for a permit to drill. The nature of the nearby entities defined in the critical well designation implies that wells in close proximity may pose greater risk to public health and safety. However, the state deems these health and safety risks as sufficiently mitigated through provisions related to how the well is maintained and operated, specifically through requirements related to surface- and subsurface-safety devices (see 14 Cal. Code Regs. § 1724.3).

State regulations that address well location restrictions or setbacks more directly are found in 24 C.C.R. § 5706.3 as part of the California fire code whereby:

> *"Wells shall not be within 100 ft of buildings not necessary to the operation of the well" (24 Cal. Code Regs. § 5706.3.1.3)*

Additionally,

> *"Wells shall not be drilled within 300 feet of building with an occupancy in Group A, E, or I." (24 Cal. Code Regs. § 5706.3.1.3.1)*

Generally, building groups are defined in terms of their occupancy classifications, where buildings in Group A refer to buildings where persons gather such as churches, civic buildings, restaurants, movie theaters, etc. Buildings in Group E refer to educational use types such as daycare facilities and schools. And finally, building Group I refers to institutional use types generally referring to health care facilities and correctional facilities.

Also of note with the California Fire Code are regulations related to the siting of new buildings in relation to existing wells, commonly referred to as a reverse setback:

> *"Where wells are existing, buildings shall not be constructed within the distances set forth in Section 5706.3.1 for separation of wells or buildings." (24 Cal. Code Regs. § 5706.3.1.3.2)*

No explicit exceptions are defined in the State Fire Code, however, jurisdictions may amend to include exceptions. From the hyperlocal proximity section (Section 7.4.5), it's clear that a number of active-producing wells are within these setback distances of 100 ft (30 m) from buildings not necessary to the operation of the well.

7.2.3. California's well siting regulations and relevance to public health

At the time of writing this report, California's 100 to 300 ft (30 to 91 m) setback distances are the least stringent of all major oil and gas producing states (**Table 7.1**, **Table 7.2**). In terms of distance, Ventura County exhibits the most stringent setback regulation, with 1,500 ft (457 m) for residential dwellings and 2,500 ft (762 m) for schools. California's oil and gas regulations are conditional in nature and apply to both the source (i.e., gas storage wells) and receptor (i.e., building use type). However, the recently updated regulations for underground gas storage wells implies differential risk treatment by well type or function (14 Cal. Code Regs. § 1726, 2021). This type of provision could be adopted in future setback regulations to address certain well types and extraction techniques that are relatively unique to California, such as steam flooding secondary recovery, as well as various stimulation techniques (e.g., hydraulic fracturing, acid fracturing) with risks that warrant differential treatment. The recently updated underground gas storage regulations also adopted more formal risk management plans, which require evaluation of surrounding areas to better determine where people live and recreate and how those areas are predicted to change in the future (14 Cal. Code Regs. § 1726.3, 2018). This type of formal, proactive risk management regime, which considers future population growth, is unprecedented and could be adopted in other producing regions to better plan for ongoing population sprawl in certain areas of California.

Regarding reverse setbacks, the well location restrictions within the California Fire Code indicate that high occupancy buildings merit special protection (24 Cal. Code Regs. § 5706.3.1.3.1). For example, hospitals and schools require a 300 ft (91 m) setback, compared to 100 ft (30 m) for other building use types (**Table 7.2**). Similarly, designating a well as "critical" based upon its location in relation to nearby entities provides precedent for treating a subset of wells more stringently based solely upon location to nearby receptors. It is unclear, however, whether the critical well designation occurs retroactively in the event of new building construction within 100 to 300 ft (30 to 91 m) of an existing well. Nonetheless, the critical well inclusion criteria could be expanded to include similar pollution control mitigation measures, in addition to safety systems based upon the current understanding of adverse human health impacts associated with increased risks of exposure from nearby oil and gas activity. The presence of reverse setback within the California Fire Code is unique — no other state exhibits a statewide reverse setback regulation (Fry et al., 2017), though some local governments in the United States have adopted a reverse setback (Fry et al., 2017).

7.2.4. Summary of oil and gas sources and receptors considered in setback policies in California and beyond

7.2.4.1 Sources targeted by setback policies

Generally, oil and gas related surface setback regulations originate from the wellhead location. Very often though, the wellhead does not represent the primary hazard source on an extraction site. Human health and safety hazards on an OGD site vary across many different factors, including the nature of the activity and presence of certain equipment and systems. Some support infrastructure (e.g., condensate and circulation tanks, produced water tanks, pneumatic devices, flares) may represent important pollutant emissions sources; however, support infrastructure generally entails a separate permitting process and therefore much less information is available related to their presence on site (Koehler et al., 2018). Moreover, regulatory permitting processes generally focus on an individual well as the functional unit of interest (CalGEM, 2019). Therefore, well location is typically used to proxy for the entirety of an OGD site in the context of setback regulations (**Table 7.1**).

To be more inclusive of surface infrastructure on well sites, Colorado recently enacted new setback regulations. Instead of a wellhead, the setbacks are measured from the boundary of the working pad surface (COGCC Rules 600 Series, 2021). This area boundary designation was intended to encompass all pad-related activity, creating a more inclusive setback source target. This was likely in response to the increasing use of larger, multi-well well pads that in some cases could legally permit receptors such as homes to be located directly against a well pad fence line if the well(s) were on the opposite end of the well pad. The justification of the working pad setback target can be justified by the following thought experiment. Depending on the size and orientation of the well(s) on a well pad, it is conceivable that a shorter setback distance targeted at the working pad boundary could encompass more surrounding land area than a longer setback distance targeted at individual wells. Therefore, defining the setback at the boundary of the working pad can better guarantee that distance set is adhered to regardless of the location of wells and infrastructure on a well pad.

7.2.4.2 Setback receptors targeted by setback policies

Compared to oil and gas sources, policies defining setback receptor types have varied much more in practice. The most commonly defined setback receptors are buildings, although some conditionality exists related to likelihood of inhabitation or explicit building use type. For example, in the Pennsylvania state code (and as it is applied in Pennsylvania's well siting requirements), a building is defined as:

> *"an occupied structure with walls and a roof within which individuals live or customarily work" (58 Pa. Cons. Stat. § 3301, 2016).*

This indicates that the building setback regulation in Pennsylvania is conditional upon the presence of human activity, not necessarily by a land use type designation like "residential," as was explicitly defined in Colorado's regulations:

> *"No Working Pad Surface will be located more than 500 feet and less than 2,000 feet from 1 or more Residential Building Units or High Occupancy Building Units"* (COGCC Rules 600 Series, 2020).

Restrictions on what counts as a building depend on the local jurisdiction's definition of a building. Some jurisdictions put no additional qualifying definitions on "building," while others place size requirements, such as in the City of Los Angeles (e.g., >400 ft^2 [37 m^2] area, 36 ft [11 m] tall). Some localities define a building as any structure not utilized for oil and gas development (Los Angeles, CA Muni. Code § 91.6105, 2019).

Outside of general building-use definitions, many jurisdictions have also enacted more stringent setback requirements for sensitive receptor locations and typically occupied spaces alongside the more general building setback regulation (**Table 7.1**, **Table 7.2**). Some jurisdictions have enacted setback provisions for certain water-related and environmentally sensitive receptors, such as drinking water wells, groundwater intake of a public water supply, surface water bodies, and perennial streams and springs. However, the most common sensitive receptors related to oil and gas well setbacks have been schools, hospitals, senior care facilities, faith institutions, parks and places of public assembly. Notably, some jurisdictions have defined these types of receptors at the property line boundaries as opposed to a physical structure on the property. Defining receptors at a property line boundary provides additional criteria designed to reduce potential exposures to persons that may frequent the areas adjacent to the building in question.

7.2.5. Exemptions and exceptions considered in setback policies

Given the importance of distance in reducing the exposure risks and health effects for populations near oil and gas development, exemptions or exceptions to setback provisions are important to consider. In practice, exemptions and exceptions also have a bearing on land use co-locations and impacts from oil and gas development on surrounding populations. Here we briefly discuss a range of codified setback exemptions and exception provisions that have been applied elsewhere in the United States, and examine the current understanding related to data on the frequency of setback exemptions and exceptions.

In the United States, mineral rights can be owned by private landowners, private companies, and federal, state, or local governments (Fry, 2013). The ownership of mineral rights generally affords the owner the right to exploit or produce said minerals even if the mineral rights owner may not own the overlying surface rights (i.e., split estate). Thus, within the context of regulatory setback provisions, some exemptions and exceptions (e.g., landowner consent waivers, regulatory distance variance) exist so as to not limit a mineral rights owners' right to realize access to owned resources.

Conditional exemptions and exceptions are often clearly stated alongside well location restrictions. For example, Pennsylvania's setback regulation applies only to new wells drilled on new well pads — effectively exempting new wells on the more than 2,000 existing well pad areas that predated the regulation (Michanowicz et al., 2021). Pennsylvania allows for exceptions from its 500 ft (152 m) building setback requirement through two mechanisms, typically referred to as a consent waiver or request for variance, respectively:

- Where written consent from the surface landowner is submitted with the Permit Application to Drill and Operate an Unconventional Well.
- If the applicant "submit[s] a Request for Variance from Distance Restriction to the regulator detailing additional terms and conditions to be in place to ensure safety and protection to persons and property."

Recently, Colorado passed a 2,000 ft (610 m) setback for residential buildings, high occupancy buildings, schools, and childcare centers with varied exception language for each (COGCC Rules 600 Series, 2021). Unlike Pennsylvania, existing well pad locations were not exempted from updated well siting restrictions. Colorado does however allow setback exceptions. For a well to be sited within 2,000 ft (610 m) of a residential building unit in Colorado, one or more of the following conditions must be met:

- The residential building unit owners and tenants and high occupancy building unit owners and tenants within 2,000 feet (610 m) of the working pad surface explicitly agree with informed consent to the proposed oil and gas location;
- The location is within an approved comprehensive area plan that includes preliminary siting approval pursuant to Rule 314.b.(5) or an approved comprehensive drilling plan;
- Any wells, tanks, separation equipment, or compressors proposed on the oil and gas location will be located more than 2,000 feet (610 m) from all residential building units or high occupancy building units; or
- The commission finds, after a hearing pursuant to Rule 510, that the proposed oil and gas location and conditions of approval will provide substantially equivalent protections for public health, safety, welfare, the environment, and wildlife resources, including disproportionately impacted communities (COGCC, 2020).

Overall, very little data has been reported on how often exemptions or exceptions result in a well placed within the setback distance. Requests for variances are common in some areas, however. Data from Flower Mound, Texas, shows that since its gas-drilling ordinance began in 2003, almost 80% of pad sites received a variance to drill at a distance less than the 1,500 ft (457 m) setback (American Bar Association, 2018). Similarly, 13 of the 16 wellpads constructed since 2001 in Arlington, Texas, received waivers to drill within its 600 ft (183 m) setback requirement (Thibodeaux, 2018). Outside of Texas, a 2014 West Virginia land use study showed that five wellpads surrounding forty homes were within the state's setback distance of 625 ft (191 m). However, many of the wellpads likely predate West Virginia's 2012 setback regulation (W. Va. Code § 22-6A-12) thereby exempting them from regulation (Hansen et al., 2017).

More recently, Michanowicz et al. (2021) assessed the effectiveness of a statewide setback regulation by evaluating the Pennsylvania Oil and Gas Act (Act 13) of 2012, which increased the unconventional natural gas (UNG) well-to-building setback requirement from 200 to 500 ft (61 to 152 m). A detailed spatial analysis revealed trends in wellhead locations and proximity to likely occupied buildings between 2008–2018. On average, one out of every 13.7 UNG wells drilled in Pennsylvania were drilled within the setback distance after the passage of Act 13 in 2012. The authors found that despite the strengthened setback regulation, some wells were still sited within the setback distance. This is likely due to existing well pad exemptions (35%) and a combination of landowner consent and regulatory distance variances, rather than encroaching building development. After adjusting for the underlying well-to-building trend over time, the researchers found that Act 13 did not significantly alter how wells were sited in relation to nearby buildings — observing no change to the underlying trend. From this analysis the authors concluded,

"Despite the regulation's intent, the study found no significant change in how wells were sited after Act 13 took effect in 2012. These findings suggest that exemptions, variances, and consent waivers provide opportunities to avoid or weaken well-siting requirements."

Because Pennsylvania exempted existing well sites from the setback regulation, researchers also tested whether the new regulation actually increased drilling on existing well pads to potentially avoid well siting restrictions but did not observe this phenomenon. The researchers did, however, find that if existing well pads had not been exempted and no new setback incidents occurred on these pre-Act 13 well pads, then Act 13 would have significantly reduced the setback incident rate by up to 46% (Michanowicz et al., 2021).

The following policy recommendations were included that are applicable to California:

- New setback regulations should include additional protective mitigation measures when an existing well pad is altered and/or require both regulatory approval and landowner consent.
- Regulators could routinely track and report well siting exemption rates and rationales, and, if warranted, consider changes to setback rules to narrow exemptions that are used too frequently.
- Regulators could ensure better landowner consent provisions; for instance, by requiring that the operator demonstrate to the landowner and the regulator that there is no alternative siting possible before landowner consent can be obtained.
- Regulators could increase transparency by making setback exemption permits publicly available online alongside other commonly reported well permit information.

7.2.6. Summary of findings from previous California proximity analyses

There have been multiple studies of populations living near oil and gas development in California (Deschenes et al., 2021; Gonzalez et al., 2020; Shamasunder et al., 2018; K. V. Tran et al., 2020), resulting in both new understandings of potential health effects and key insights into California's unique land use issues, particularly in urban settings. At least 10 formal proximity analyses have been performed in the state of California. Appendix F.7 lists these studies, along with brief descriptions of their inclusion criteria and key findings. Results are summarized below.

In 2014, the Natural Resources Defense Council (NRDC) conducted a proximity analysis (Srebotnjak & Rotkin-Ellman, 2014). This analysis found that approximately 5.4 million California residents live within 1 mi (1,609 m) of more than 84,000 existing oil and gas wells.[1] When accounting for environmental burden, the NRDC found that more than 1.8 million (~33%) of these residents also reside in census tracts most burdened by environmental (soil, air, water) pollution. Czolowski et al. (2017) performed a national-level human population proximity analysis. Using a much more conservative well inclusion criteria restricted to active wells, the study found an estimated 2.09 million Californians living within 1 mi (1,609 m) of an oil or gas well in 2014.

[1] This analysis accounted for all active and new wells (including unconventional wells) using the California Division of Oil, Gas and Geothermal Resources (DOGGR, now CalGEM) "AllWells" and "Well Stimulation Treatment Notices Index" databases, the South Coast Air Quality Management District (SCAQMD) "Oil and Gas Wells Activity Notification" database, and the chemicals disclosure registry database provided by FracFocus.org.

In 2015, pursuant to SB 4, the California Council on Science and Technology (CCST) produced a report on well stimulation in California. An assessment within this report found that approximately 12% of the South Coast Air Basin (i.e., Los Angeles Metropolitan Area) population (~2.3 million people) lives within 2 km (6,562 ft) of an active oil and gas well (Shonkoff and Gautier, 2015). In addition, an estimated 184 daycare facilities, 213 elderly care facilities and approximately 628,000 residents are within 800 m (2,625 ft) of an active oil and gas well in the Los Angeles Basin. Additionally, 32,000 residents, including approximately 2,300 children less than five years old, live within 100 m (328 ft) of an active well (Shonkoff and Gautier, 2015). A state-wide analysis by Ferrar (2020) found about 2.17 million Californians live within 2,500 ft (762 m) of an operational oil and gas well, with an estimated 7.37 million Californians within 1 mi (1,609 m).

The Oil and Gas Threat Map from Earthworks (2016) used a half-mile (2,640 ft, 805 m) as the setback distance, or “threat radius”, when evaluating proximity to oil and gas infrastructure. A key finding was that 1,126,071 people were estimated to live within a half-mile of oil and gas infrastructed with an estimated 309,135 students in the radius, and 678 schools and daycare centers. Shonkoff and Hill (2019) found that as of 2015, about 630,000 residents, 130 schools, 213 elderly care facilities, and 184 daycare facilities were sited within a half-mile (2,625 ft, 800 m) of an active oil and gas well in the Los Angeles Basin alone. The authors noted that more than 32,000 people in the Los Angeles Basin are estimated to live within 100 m (328 ft) of an active oil and gas well.

In summary, these proximity analyses show that a large number of California residents and sensitive receptors are close to upstream oil and gas activities. The estimates provide context for the population-level burdens facing many communities. However, key limitations exist. Four of the studies were performed before 2016 or used pre-2016 well data, so their well and population counts are likely outdated. Of the studies that assessed the entire state of California and used all producing well types, only one used census block data (Czolowski et al., 2017) — the highest spatial resolution available within the U.S. Census. However, Czolowski et al. (2017) only used active wells that produced hydrocarbons in 2014, effectively undercounting the idle wells that are prevalent in California. Czolowski et al. (2017) also did not remove non-habitable land uses prior to allocating populations to buffer-areas around wells.

7.2.7. Implications of setbacks for decarbonization, production, air quality, and health

Most recently, a study commissioned by the California Environmental Protection Agency (CalEPA) examined various pathways and implications of decarbonizing California’s oil extraction and refining sectors (Deschenes et al., 2021). Broad in scope, the study examined 1,440 different scenarios related to extractive industries in California, with projections across multiple outcomes including greenhouse gas and air pollutant emissions, health benefits, and labor market impacts with a specific focus on equity. Most applicable to this report are two policy scenarios related to setbacks and a statewide crude oil production quota. First, it was found that a 2,500 ft (762 m) setback scenario alone was not sufficient to achieve 80–90% decarbonization by 2045. A 2,500 ft (762 m) setback between wells and residences, schools, playgrounds, daycare centers, elderly care facilities and hospitals leads to a 49% greenhouse gas reduction between 2019–2045. Increasing the setback to 5,280 ft (1 mile, 1,609 m) results in a greenhouse gas reduction of 58%. In addition to greenhouse gas reductions, they found that setbacks generate statewide health benefits to nearby populations in terms of reductions in air pollution. Specifically, premature mortality and the incidence of adverse health outcomes are projected to decline by 17% to 37% cumulatively over 2019–2045, depending upon the setback distance promulgated with greater health benefits for larger setbacks compared to a scenario without a setback policy.

The authors also found that a second policy type — a statewide production quota or equivalent severance tax on extraction — was found to disproportionately reduce impacts on disadvantaged communities. Under this production quota, the authors identified an "equity benefit" whereby a greater share of the reduced air pollution exposure occurred in disadvantaged communities. This occurs since higher cost extraction activities tend to be co-located in areas with more disadvantaged communities. Therefore, under this policy scenario, these more expensive extraction activities may be more likely to be attenuated given their relative costs compared to less costly production fields that are not located in or near disadvantaged communities. Overall, they found that between 27% to 39% of the projected health benefits and between 50% to 59% of the reduced population exposure to air toxics accrue to disadvantaged communities. Further examining these results showed that a significant share of the health benefits is captured by neighborhoods in the city of Bakersfield.

7.3. Updated California Proximity Analysis: Approach & Methods

As a basis for understanding potential public health hazards attributable to upstream oil and gas development, we evaluated the spatial relationships of active (producing) oil and gas wells and wastewater disposal locations to the surrounding population and selected sites considered to be sensitive receptors. The analyzed sensitive receptors include schools (pre-K to 12th grade), childcare facilities, healthcare facilities, senior care facilities, correctional facilities, parks, and residential buildings. We also characterized the demographics, susceptibility factors, and socioeconomic profiles of the communities in proximity to areas of increased well densities. Other chapters in this report also inform our proximity analysis, including Chapter 2, stressors associated with OGD; Chapter 3, epidemiological studies; Chapter 4, air quality risk assessment studies; and Chapter 5, produced water management studies. In addition to these chapters, methodological considerations were also informed by previous California proximity studies, existing surface setback and well siting location regulations in California and throughout the United States, and distributional inequities observed within the peer-reviewed literature (**Figure 7.1**).

Overall, the new proximity analysis presented here improves upon previous California proximity analyses in three main ways. First, this proximity analysis provides the most spatially precise estimates of populations living within California to date. This proximity analysis overcomes common issues of downscaling populations to census aerial units (particularly in rural areas) by utilizing a combination of census blocks, residential tax parcels, and building footprint data depending upon the relative population density at hand. Second, this analysis includes numerous demographic and contextual variables and key sensitive receptors at the building footprint and area extent resolutions such as schools, health care facilities, and — unique to this analysis — residentially-zoned buildings. And finally, with use of individual building footprint locations, we were able to assess hyperlocal proximities between homes and wells at distances less than 500 ft (152 m) (see Section 7.4.5). This degree of spatial accuracy has not been used before in California or elsewhere in performing a similar proximity analysis.

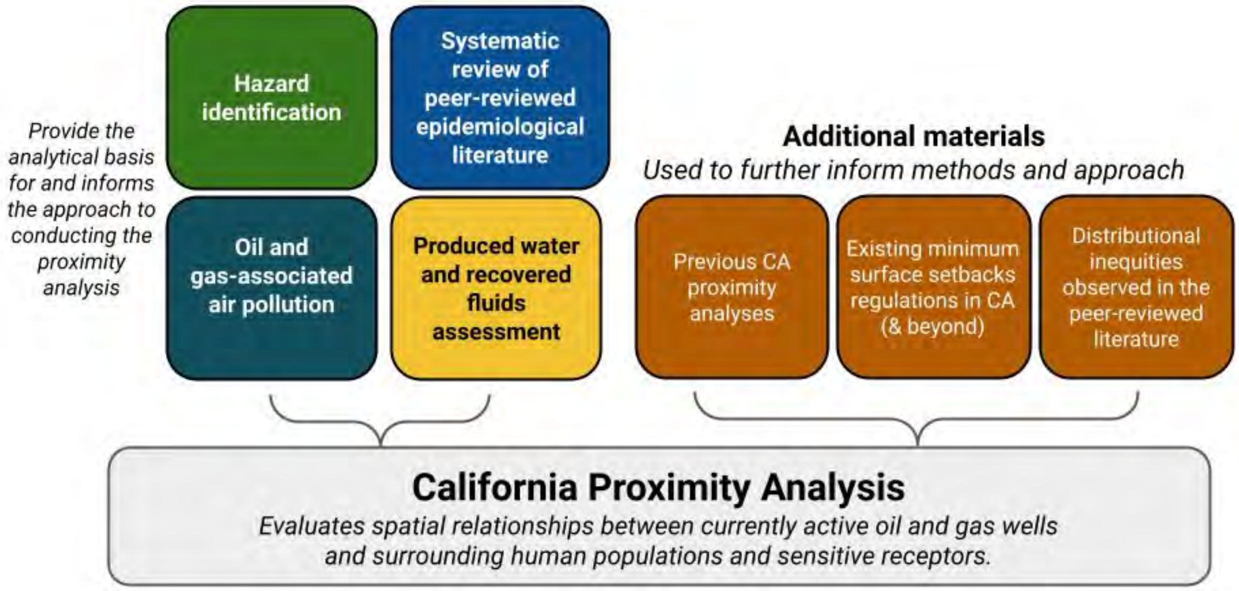

Figure 7.1. Approach to inform the California proximity analysis.

7.3.1. Methods

Details concerning data sources and methods used in the proximity analysis are provided in Appendices F.1 and F.2, respectively. Briefly, the proximity analysis is organized into four main analytical components:

- Population counts and demographics at the sub-census block level near active-producing oil and gas wells and wastewater locations (i.e., active produced water ponds and all-status water disposal wells).
- Counts of sensitive land uses and receptors[2] near oil and gas wells and wastewater locations.
- An assessment of active well density and population-level factors at the census tract level.
- An assessment of hyperlocal proximity between wells and sensitive receptors <500 ft (<152 m).

[2] Spatial resolutions of sensitive receptors ranged from the area extent of the land use parcel to the nearest building footprint and are included as footnotes for all relevant tables. Receptor area extents were available only for public schools (K–12), universities and community colleges, and parks. Two-dimensional building footprints were used for all other sensitive receptors available from Microsoft. Receptors that were only available as geographic coordinates such as childcare centers and senior care facilities, were spatially joined to the nearest building footprint.

The study area encompasses the entire state of California, with some aggregate analyses performed at the California air basin level. The most up to date oil and gas well and wastewater data were used in the proximity analysis (current up to January 2021). Our well inclusion criteria were designed to capture wells capable of producing hydrocarbons as of March 2021 and took into account a well's status and type, resulting in 83,834 "active-producing" wells across California. Our well selection criteria is discussed briefly below, with additional detail provided in Appendices F.1 and F.2, respectively.

Oil and gas extraction in California is supported by numerous well types in various operating conditional states (i.e., status). Thus, our well inclusion criteria aimed to capture wells that were capable of producing hydrocarbons at the time of writing this report and into the near future. To capture wells capable of producing hydrocarbons, both well type and well status were considered in tandem. Because not all well types produce oil or gas, first we determined which well types were capable of producing any oil or gas. We defined "producing" wells as any well type whereby at least 1% of the wells within that well type produced oil or gas within the past five years. If this 1% threshold was met, all wells of that type were deemed capable of producing and were carried on to the subsequent stage of filtering — filtering by well status. "Producing" wells were then deemed "active", only if they held one of the following statuses — *active, new, or idle* — as of January 21, 2021. By using these criteria, 83,834 wells were identified and included in this proximity analysis. Wells hereafter are referred to as "active-producing."

Of the 2,389 pond features in the aggregated produced water disposal pond dataset, only those with a status of "active" (n=682) were included and were joined to all wells with a type of "water disposal" from the CalGEM "All Wells" dataset (n=2,295). Thus, a total of 2,977 wastewater disposal features were considered for the wastewater portion of the statewide proximity analysis.

7.4. Results

7.4.1. Socioeconomic disparities and total populations in proximity to oil and gas development

An estimated 3 million, or roughly 1 in 12 (~8%), California residents live within 1 km (3,281 ft) of an active-producing oil and gas well (**Table 7.3**). The 1 km (3,281 ft) radial buffer areas around all wells encompass just 1.7% of all land area in California, indicating that wells are disproportionately clustered in more densely populated areas. More than 95% of active-producing wells included in this analysis are within three California Air Basins — the San Joaquin Valley, the South Central Coast, and the South Coast (**Figure 7.2**). The degree of well clustering in some areas has implications for public health. Some schools and healthcare facilities are located within 1 km (3,281 ft) of hundreds of active oil and gas wells.

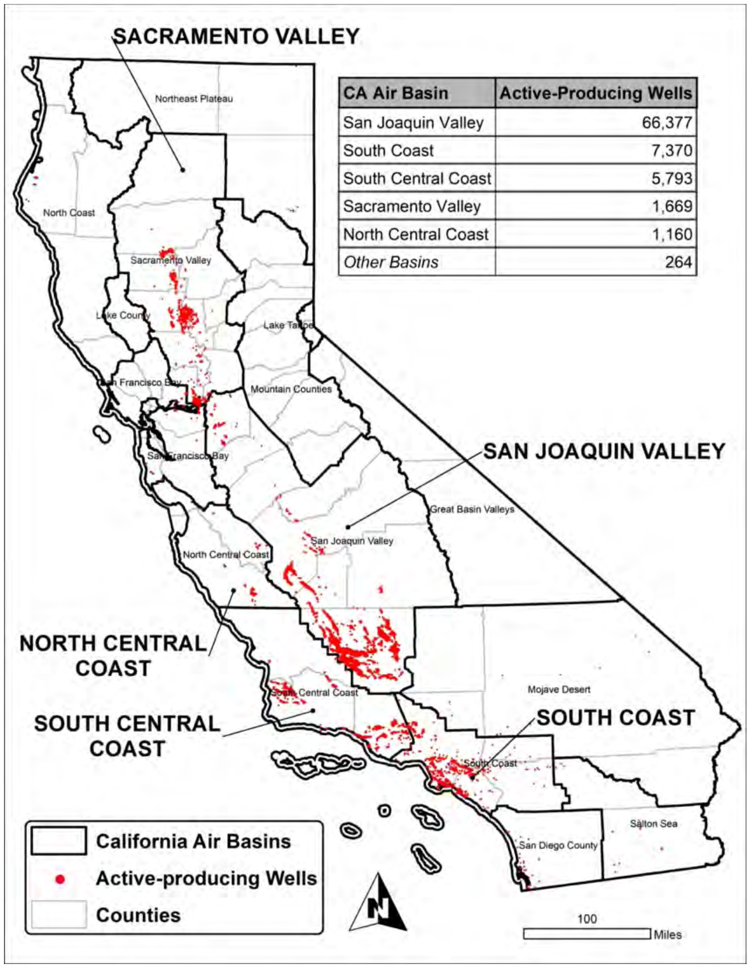

Figure 7.2. Active-producing oil and gas wells within each California Air Basin.

Nearly 15% of the 3 million California residents that live within 1 km (3,281 ft) of OGD are susceptible to health risks from exposure to poor air quality due to age alone (i.e., under 5 or over 64 years old). These age-groups were not found to be overrepresented in areas proximal to wells as was observed for certain socio-economic classifications. Across the landscape of oil and gas development (OGD) in California, we observed exposure disparities by race and ethnicity, as well as disparities for linguistically isolated households, renter status, and educational attainment. We evaluated demographic metrics to determine if certain populations were disproportionately represented in areas near OGD throughout California (**Figure 7.3**). Disparities were calculated by comparing the proportion of each demographic group living within 1 km (3,281 ft) of OGD to the proportion of that group present throughout the state (see Appendix F.2.4).

Overall, these demographic metrics indicate that non-Hispanic Black populations are disproportionately exposed to nearby OGD throughout California — non-Hispanic Black populations are about 50% (factor of ~1.5) more likely to have at least one well within 1 km (3,281 ft) of their residence (**Figure 7.3**) compared to the California average. Compared to non-Hispanic White populations in California, non-Hispanic Black populations are 87% more likely to reside in areas that contain OGD within 1 km (3,281 ft). Population-level inequities were also observed for populations who identify as Hispanic. White populations are 20% less likely than the average

Californian to live in areas with OGD within 1 km (3,281 ft). Overall, these findings indicate that environmental justice concerns exist for OGD throughout California.

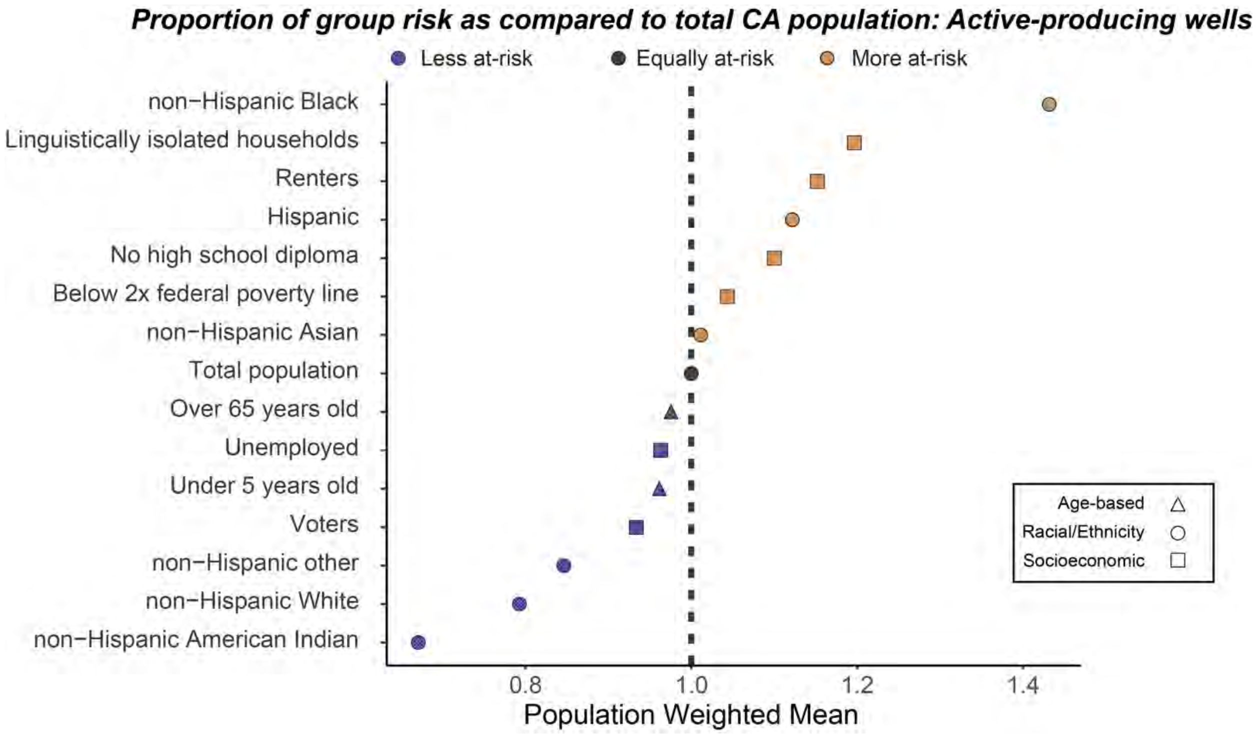

Figure 7.3. Distributional inequities of demographic groups living within 1 km (3,281 ft) of active-producing oil and gas wells as compared to state population totals derived from the 2013–2017 American Community Survey (ACS) at the census block scale. Orange markers indicate a population weighted mean greater than one, indicating a level of subgroup overrepresentation in areas that contain OGD within 1 km (3,281 ft). Blue markers indicate a level of subgroup underrepresentation in areas that contain OGD within 1 km (3,281 ft).

Table 7.3. Total counts and associated age, racial, and socioeconomic demographic metrics of populations living in proximity to active-producing oil and gas wells in 2021. Percentages are based on state totals.

	0–500 ft (0–152 m) Count (%)	0–1,000 ft (0–305 m) Count (%)	0–1,500 ft (0–457 m) Count (%)	0–2,000 ft (0–610 m) Count (%)	0–2,500 ft (0–762 m) Count (%)	0–3,281 ft (0–1,000 m) Count (%)	0–5,280 ft (0–1,609 m) Count (%)
Total Population	219,681 (0.6)	590,116 (1.5)	1,032,255 (2.6)	1,551,743 (4.0)	2,123,961 (5.4)	3,080,713 (7.9)	5,772,699 (14.8)
Age Based							
under 5 years old	15,110 (0.6)	39,476 (1.5)	68,909 (2.6)	103,736 (3.8)	141,733 (5.3)	205,027 (7.6)	384,810 (14.3)
over 64 years old	30,959 (0.6)	82,984 (1.6)	143,807 (2.7)	212,905 (4.0)	287,705 (5.4)	412,674 (7.7)	760,877 (14.2)
Race/Ethnicity							
non-Hispanic White	65,646 (0.4)	183,978 (1.2)	321,774 (2.1)	479,522 (3.2)	650,338 (4.3)	938,185 (6.3)	1,715,501 (11.5)
Hispanic	90,842 (0.6)	246,340 (1.6)	438,719 (2.9)	669,110 (4.4)	923,441 (6.0)	1,357,219 (8.9)	2,639,604 (17.2)
non-Hispanic Black	17,745 (0.8)	48,233 (2.1)	86,994 (3.8)	134,633 (5.8)	185,633 (8.0)	262,347 (11.3)	458,697 (19.8)
non-Hispanic Asian	42,687 (0.8)	99,443 (1.8)	161,873 (2.9)	232,534 (4.1)	313,918 (5.6)	448,648 (8.0)	817,887 (14.6)
non-Hispanic American Indian	1,056 (0.5)	2,385 (1.1)	4,001 (1.9)	5,869 (2.8)	7,909 (3.7)	11,299 (5.3)	21,110 (9.9)
non-Hispanic other	7,328 (0.5)	18,800 (1.3)	32,142 (2.3)	48,202 (3.4)	65,911 (4.6)	94,843 (6.7)	175,381 (12.4)
Socioeconomic							
below 2x federal poverty line	78,089 (0.6)	204,924 (1.5)	361,224 (2.7)	548,096 (4.1)	757,742 (5.6)	1,107,556 (8.2)	2,124,356 (15.8)
unemployed	11,905 (0.6)	30,562 (1.4)	53,393 (2.5)	80,136 (3.8)	109,808 (5.1)	160,954 (7.6)	306,800 (14.5)
median household income	$77,711	$77,556	$77,542	$77,260	$76,873	$76,266	$74,354
no high school diploma	44,978 (0.6)	118,312 (1.6)	208,960 (2.8)	318,387 (4.3)	440,478 (5.9)	648,729 (8.7)	1,259,987 (16.9)
voters	143,407 (0.5)	386,717 (1.4)	677,431 (2.5)	1,017,076 (3.7)	1,389,846 (5.1)	2,011,686 (7.4)	3,774,238 (13.9)
renters	129,440 (0.7)	325,718 (1.9)	549,488 (3.1)	815,155 (4.6)	1,108,908 (6.3)	1,599,720 (9.1)	3,016,193 (17.2)
linguistically isolated households	11,794 (0.9)	27,282 (2.0)	45,417 (3.3)	66,871 (4.9)	89,993 (6.6)	128,834 (9.5)	242,573 (17.8)

7.4.2. Socioeconomic disparities and total populations in proximity to wastewater

An estimated 400,000, or roughly 1 in 100 (1%), California residents live within 1 km (3,281 ft) of an active produced water disposal pond, or any water disposal well (**Table 7.4**). Overall, population trends for proximity to wastewater features are generally similar to total population trends for active-producing wells. For example, no significant disparities were observed between age groups. This is likely due to the significant geographic overlap (at least 70%) between wastewater features and active-producing wells (further discussed in Appendix F.4, Table F.5). This reflects the nature of OGD, where it is common for other portions of the oil and gas supply chain, such as wastewater disposal systems, to be co-located with wells.

The remaining 30% of land surface area that is unique to wastewater feature buffer areas appears to contain populations that are distinct from populations within active-producing well buffer areas. Consequently, slightly different population-level disparities are observed within water feature buffer areas. Nonetheless, non-Hispanic Black populations are also disproportionately exposed to nearby wastewater locations throughout California (**Figure 7.4**), though slightly less than the disparities observed for active-producing wells (**Figure 7.3**). In contrast to the oil and gas well analysis above, here we observe over-representation of non-Hispanic White populations living within 1 km (3,281 ft) of wastewater facilities. Populations two times below the poverty line were least likely to live near a wastewater feature. Combined, these results indicate that wastewater facilities do not completely mimic population-level inequities observed for OGD, suggesting that different populations across California may be disproportionately burdened by various sub-sectors of the oil and gas supply chain. From a policy perspective, these findings have implications for understanding which populations will be most and least protected under different regulatory scenarios for oil and gas activities in California.

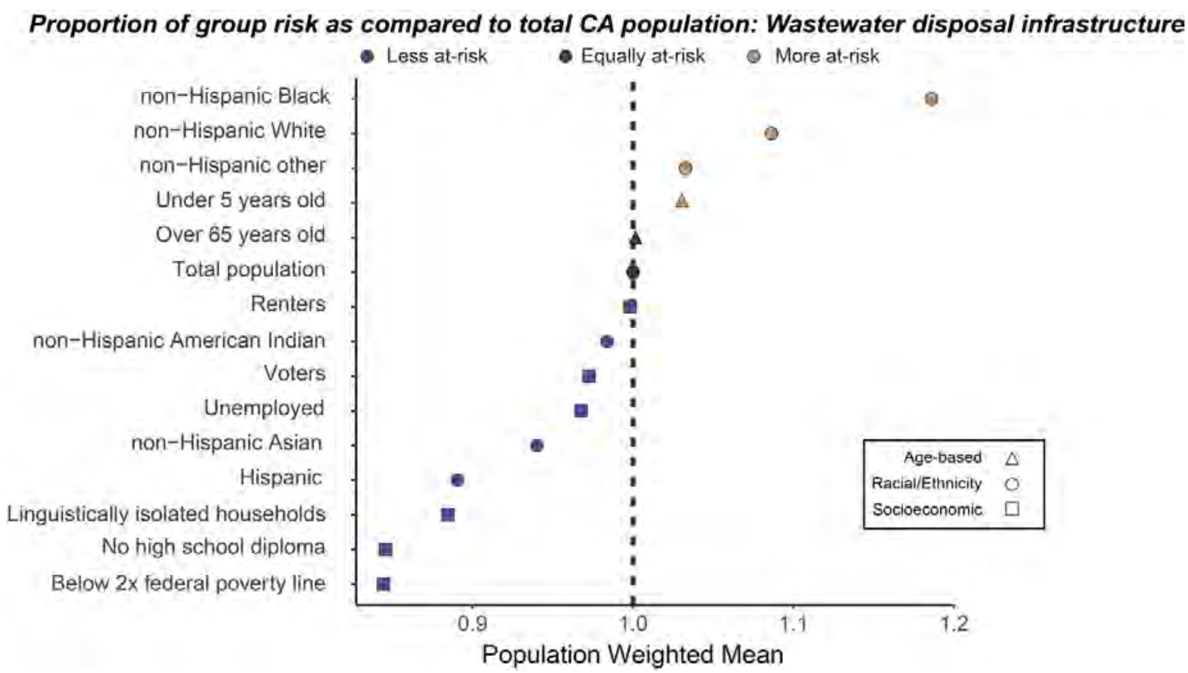

Figure 7.4. Distributional inequities of demographic groups living within 1 km (3,281 ft) of active produced water disposal ponds and water disposal wells as compared to total population. Orange markers indicate a population weighted mean greater than one indicating a level of subgroup overrepresentation in areas that contain OGD within 1 km (3,281 ft). Blue markers indicate a level of subgroup underrepresentation in areas that contain OGD within 1 km (3,281 ft).

Table 7.4. Total counts and associated age, racial, and socioeconomic demographic metrics of populations living in proximity to active produced water disposal ponds and any water disposal wells in 2021. Percentages are based on state totals.

	0–500 ft (0–152 m) Count (%)	0–1,000 ft (0–305 m) Count (%)	0–1,500 ft (0–457 m) Count (%)	0–2,000 ft (0–610 m) Count (%)	0–2,500 ft (0–762 m) Count (%)	0–3,281 ft (0–1,000 m) Count (%)	0–5,280 ft (0–1,609 m) Count (%)
Total Population	7,058 (<0.1)	33,253 (0.1)	80,099 (0.2)	149,654 (0.4)	236,921 (0.6)	402,463 (1.0)	1,023,614 (2.6)
Age Based							
under 5 years old	624 (<0.1)	2,411 (0.1)	5,602 (0.2)	10429 (0.4)	16,910 (0.6)	28,706 (1.1)	72,115 (2.7)
Over 64 years old	1,147 (<0.1)	5,004 (0.1)	11,645 (0.2)	21357 (0.4)	32,923 (0.6)	55,346 (1.0)	132,782 (2.5)
Race/Ethnicity							
non-Hispanic White	2,672 (<0.1)	13,553 (0.1)	33,185 (0.2)	62115 (0.4)	98,754 (0.7)	167,957 (1.1)	398,169 (2.7)
Hispanic	2,499 (<0.1)	11,377 (0.1)	27,833 (0.2)	51166 (0.3)	80,604 (0.5)	141,102 (0.9)	405,774 (2.7)
non-Hispanic Black	922 (<0.1)	3,348 (0.1)	6,880 (0.3)	12243 (0.5)	18,126 (0.8)	28,323 (1.2)	70,707 (3.0)
non-Hispanic Asian	1,031 (<0.1)	4,487 (0.1)	10,464 (0.2)	20450 (0.4)	33,330 (0.6)	54,603 (1.0)	122,999 (2.2)
non-Hispanic American Indian	120 (0.1)	281 (0.1)	572 (0.3)	928 (0.4)	1,357 (0.6)	2,165 (1.0)	4,842 (2.3)
non-Hispanic other	393 (<0.1)	1,502 (0.1)	3,383 (0.2)	6007 (0.4)	9,312 (0.7)	15,121 (1.1)	34,705 (2.4)
Socioeconomic							
below 2x federal poverty line	2,128 (<0.1)	9,471 (0.1)	22,918 (0.2)	4,3093 (0.3)	67,829 (0.5)	117,070 (0.9)	333,441 (2.5)
unemployed	533 (<0.1)	1,908 (0.1)	4,298 (0.2)	7,865 (0.4)	12,471 (0.6)	21,140 (1.0)	54,944 (2.6)
Median Household Income	$ 80,630	$ 80,356	$ 80,154	$ 80,509	$ 80,129	$ 79,459	$ 75,982
no high school diploma	1,215 (<0.1)	5,318 (0.1)	12,656 (0.2)	23,326 (0.3)	37,154 (0.5)	65,144 (0.9)	194,110 (2.6)
voters	4,876 (<0.1)	22,619 (0.1)	54,557 (0.2)	102,009 (0.4)	160,832 (0.6)	273,598 (1.0)	680,967 (2.5)
renters	3,094 (<0.1)	14,533 (0.1)	35,164 (0.2)	66,949 (0.4)	106,818 (0.6)	181,056 (1.0)	492,002 (2.8)
linguistically isolated households	307 (<0.1)	1,178 (0.1)	2,546 (0.2)	4,690 (0.3)	7,293 (0.5)	12,442 (0.9)	34,011 (2.5)

7.4.3. Sensitive receptors in proximity to oil and gas development

Sensitive receptors, defined as schools (pre-K to 12th grade), childcare facilities, healthcare facilities, senior care facilities, correctional facilities, parks, and residential buildings, near at least one active oil and gas well or wastewater location are summarized in **Table 7.5**–**Table 7.10.** Of all sensitive receptors analyzed, healthcare facilities exhibited the greatest co-location burden with nearby OGD. Nearly 1 in 10 (n=207, 10%) healthcare facilities in California are within 1 km (3,281 ft) of at least one active-producing well. Just behind healthcare facilities, 461 parks (9%, or approximately 12.8 mi^2 [33.2 km^2] of park lands) are within 1 km (3,281 ft) of at least one active-producing well. An estimated 1,749 (~8%) pre-K through 12th grade schools are within 1 km (3,281 ft) of at least one active-producing well. There are also a significant number of senior care facilities and correctional institutions within 1 km (3,281 ft) of at least one active-producing well — both of which may contain large permanent populations that are mostly restricted to the confines of those respective spaces. There are also a significant number of senior care facilities and correctional institutions within 1 km (3,281 ft) of at least one active-producing well — both of which may contain large permanent populations that are mostly restricted to the confines of those respective spaces.

Compared to active-producing oil and gas wells, significantly fewer sensitive receptors are located near wastewater disposal features (CalGEM, 2021).[3] However, due to the co-location of wastewater disposal features and active-producing wells, sensitive receptors in proximity to wastewater disposal features are also generally in proximity to active-producing wells. On average, producing wells and wastewater disposal features share about 80% of the observed land uses with sensitive receptors. In other words, only 20% of the population and OGD co-locations are unique to wastewater disposal features. A detailed discussion of the overlap of water and active-producing well buffer areas can be found in Appendix F.4. Senior care facilities (n=91, 1% of California senior care facilities) were the sensitive receptor type with the greatest percentage of features within 1 km (3,281 ft) of wastewater disposal features (**Table 7.7)**. Parks were the sensitive receptor with the next highest count (n=70, or approximately 3.7 mi^2 [9.6 km^2] of park lands) located within 1 km (3,281 ft) of wastewater disposal features (**Table 7.7)**. Correctional facilities have the next highest proportion of the state total, with 7 (~2%) of the total correctional facilities in the state located within 1 km (3,281 ft) of water disposal features (**Table 7.7)**. Consequently, the discussion within this section is largely focused on sensitive receptors in proximity to active-producing wells.

It is also important to note that although we considered a sensitive receptor to be impacted by OGD if there was one nearby well, many receptors are near multiple wells. Related to potential risks of exposures, it is valuable therefore to understand if the relationships are one receptor to one well or perhaps one receptor to many wells. For example, each of the sensitive receptors counted in **Table 7.5** need only have a single nearby well to be counted. What is not reflected in **Table 7.5** are the total number of wells located nearby those sensitive receptors. In some cases, sensitive receptors are located in areas with very high nearby well densities. Therefore, we took

[3] Wastewater disposal features include active produced water disposal ponds and wells designated “Water Disposal” in the CalGEM “All Wells” dataset (CalGEM, 2021).

the sensitive receptors from **Table 7.5** and counted the total number of unique nearby wells for each distance band. The results of this exercise are shown in **Table 7.6.** and provide a relative sense of the total number of wells driving the observed land use co-locations between sensitive receptors and OGD. In addition, the same companion tables for schools and associated wells are shown in **Table 7.8** and **Table 7.9**, respectively.

Only a small proportion of total oil and gas wells in California (2-7% depending on receptor) have a school, childcare facility, healthcare facility, senior care facility, correctional facility, or park within 1 km (3,281 ft) (with the exception of residential buildings). For example, 2,377 out of 83,834 (roughly 1 in 35) wells are within 1 km (3,281 ft) of a healthcare facility (**Table 7.6**). This represents just 3% of the total well inventory, with nearly 97% of wells beyond 1 km (3,281 ft) of any Californian healthcare facility. Other sensitive receptors (except residential buildings) follow the same trend — having a disproportionately small number of wells responsible for co-locations with OGD. Another way to consider these findings is by noting that a large proportion of co-locations between OGD and sensitive receptors could be eliminated by shutting in only about 5% of California's total active-producing well inventory. Overall, these disproportionate well-to-receptor counts have important implications for informing policy and present an opportunity to realize significant risk reductions by addressing only a small proportion of existing well sites.

While a relatively small proportion of total wells in California are responsible for the sensitive receptor co-locations observed here, it is also important to determine if these wells are clustered in proximity to sensitive receptor locations. Like the analysis performed to produce **Table 7.6** — total well counts near all sensitive receptors within certain distances — we further disaggregated these data to examine the distribution of wells near individual sensitive receptor locations. Some healthcare facilities and schools are surrounded by more than 200 wells within 1 km (3,281 ft) (**Figure 7.5** and **Figure 7.6**), suggesting that there is a large range of potential risks of exposure if increased OGD density is associated with an increased risks of exposure or impacts. From a public health perspective, sensitive receptors that have hundreds of wells located within 1 km (3,281 ft) likely represent both areas of greatest risks of exposure to sensitive populations and the greatest opportunity to reduce any potential risks of exposure or harms.

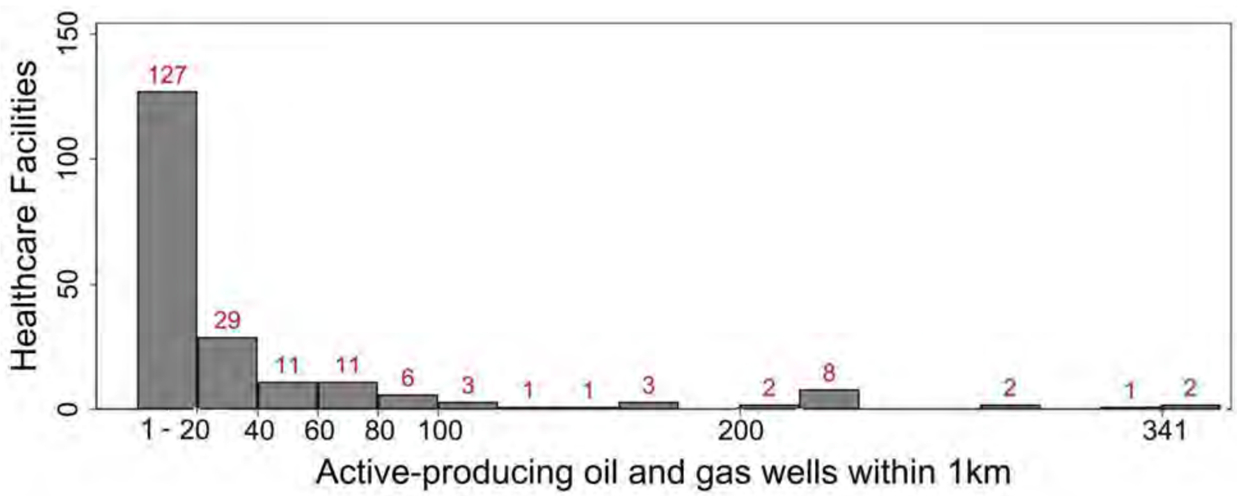

Figure 7.5. Frequency histogram of the 207 healthcare facilities in 2021 that contain at least one active-producing well within 1 km (3,281 ft). The number above each bar indicates the number of healthcare facilities within that bar. Note: the first bar of 127 healthcare facilities may contain between 1–20 wells within 1 km (3,281 ft).

7.4.3.1 Healthcare facilities

Healthcare facilities and senior care facilities are important to highlight due to the likelihood of inherent susceptibilities of individuals present at these facilities. Individuals more than 65 years old may be more susceptible to air pollution-related illnesses such as stroke, asthma, heart disease, lung cancer, and other respiratory diseases. Similarly, people with medical conditions requiring treatment at or admission to hospitals and other healthcare facilities, may suffer from exacerbation of their conditions and, further, may have increased risk of developing air pollution-related illnesses.

Nearly 1 in 10 (n=207, 10%) healthcare facilities in California are within 1 km (3,281 ft) of at least one active-producing well, representing the largest overlapping percentage observed across receptors. While only a small number of wells (~3%) are driving the land use co-locations with healthcare facilities, these wells are also highly concentrated around some healthcare facilities. For example, the 207 exposed healthcare facilities have a total of 2,377 wells within 1 km (3,281 ft). The frequency histogram of these 207 healthcare facilities and their associated 2,377 wells demonstrates a right-skewed, long-tail distribution: most healthcare facilities have fewer than ten wells nearby, whereas a few outliers have hundreds of wells within 1 km (3,281 ft) (**Figure 7.5)**. Across these 207 healthcare facilities, 69% have multiple wells within 1 km (3,281 ft), with an overall median of three wells but a mean and standard deviation of 49, and 79, respectively, indicating the long-tailed nature of the distribution. Notably, 21 healthcare facilities have more than 100 active producing wells within 1 km (3,281 ft), and 14 facilities have more than 200 — each of which is located in Los Angeles.

7.4.3.2 Schools

Schools are a particularly important sensitive receptor type, due to the presence of children and adolescents and their associated physiological susceptibilities to pollution exposures, particularly for younger children (e.g., developing lung structure and immune systems). Additionally, school children are generally confined to the school buildings or school grounds for a substantial portion of the day. Outdoor recreation associated with recess, physical education, and extracurricular activities may also place students in closer contact to associated exposures from nearby oil and gas activity.

An estimated 1,749 (~8%) pre-K through 12th grade schools are within 1 km (3,281 ft) of at least one active-producing well (**Table 7.8**). Of these, 659 are childcare centers, which include the youngest children. Similar to other sensitive receptors, fewer pre-K through 12th grade schools are within 1 km (3,281 ft) of wastewater disposal features, with only 239 (~1%) schools residing within this buffer distance (**Table 7.10**). Of those 239 schools, only 42 are unique to a wastewater disposal feature. Higher education facilities also exhibited land use co-locations with nearby wells, with 9% and 13% of community colleges and California universities, respectively, within 1 km (3,281 ft) of an active-producing well. Unlike active-producing wells, equal proportions (n=4) of universities (~3% state total) and community colleges (~2% state total) are located near wastewater infrastructure (**Table 7.10**). Only two of these higher education facilities are unique to a wastewater disposal feature.

Compared to other sensitive receptors, a larger proportion of wells are co-located with pre-K through 12th grade schools. An estimated 6,006 wells are within 1 km (3,281 ft) of at least one school, or 7.2% of active-producing wells in California. This is likely due, in part, to the large number of schools throughout California, but also the fact that schools are centered in populated areas where we also observe significant land use co-locations with residentially zoned buildings.

The distribution of unique wells within 1 km (3,281 ft) of schools (i.e., well density), like healthcare facilities, also demonstrates a right-skew with a long distributional tail (**Figure 7.6)**. Notably, of the 1,749 schools with at least one well within one kilometer, 58% of schools contain multiple active-producing wells nearby. Of these multiple-well schools, we observed a median of three wells and mean and standard deviation of 38 and 76 wells, respectively. Of the higher end of the distribution, 107 schools have over 100 wells within 1 km (3,281 ft) with 33 schools surrounded by more than 300 wells within 1 km (3,281 ft) — the majority located in Los Angeles. One Los Angeles school is surrounded by 421 wells within 1 km (3,281 ft) — the highest well density near a school observed throughout the state. Overall, due to the high degree of well clustering observed in California, sensitive receptors located near these areas are likely to have multiple wells in their proximity. Hyperlocal proximity was also observed for schools at the 500 ft (152 m) buffer distance, with an estimated 226 schools and childcare centers containing at least one active-producing well within 500 ft (152 m) of the school building. Likewise, some schools contain multiple wells within 500 ft (152 m), as indicated by the associated 865 wells counted around the 226 schools. We also assessed school-level exposure using building footprints. Consequently, students may be exposed to additional wells near outdoor school grounds that is not reflected in the proximity analyses to building footprints (e.g., playgrounds, parking lots, recreational fields).

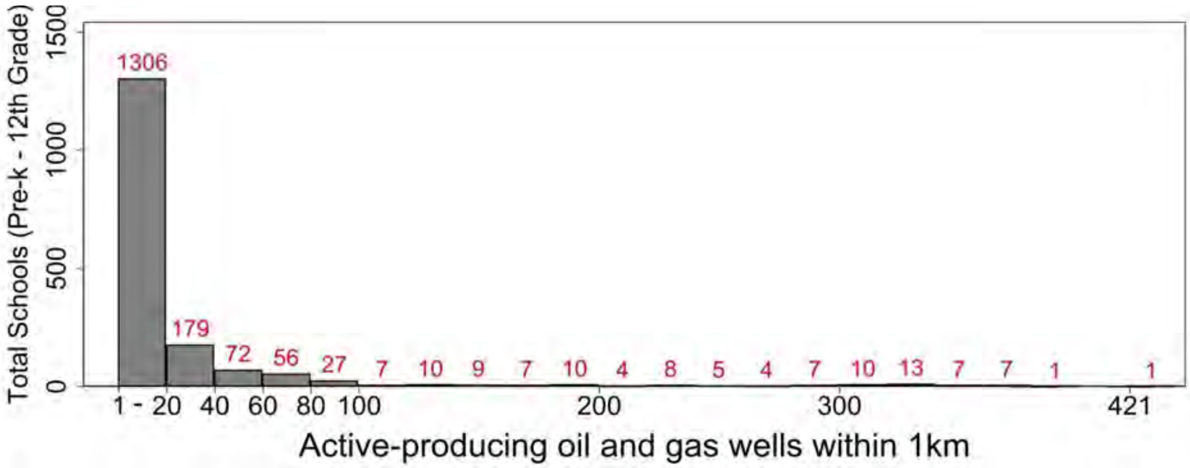

Figure 7.6. Frequency histogram of the 1,749 schools that contain at least one active-producing well within 1 km (3,281 ft). The number above each bar indicates the number of schools within that bar. Note the first bin of 1,306 schools may contain between 1–20 wells within 1 km (3,281 ft). An estimated 67 schools have at least 200 wells within 1 km (3,281 ft).

7.4.3.3 Total buildings and homes

To further verify the spatial relationships observed between populations and nearby oil and gas activity (**Table 7.3** and **Table 7.4**), we also include explicit counts of both total buildings and residentially-zoned buildings located nearby oil and gas activity (**Table 7.5** and **Table 7.7**).

In our analysis, we identified approximately 738,000 buildings within 1 km (3,281 ft) of an active-producing oil and gas well, and approximately 116,000 buildings within 1 km (3,281 ft) of a wastewater disposal feature. Only ~19,000 of the buildings near wastewater disposal features are not encompassed by the 1 km (3,281 ft) buffer extending from active-producing oil and gas wells, further illustrating that active-producing wells impact a substantially larger number of nearby receptors than wastewater disposal features.

The 738,000 buildings within 1 km (3,281 ft) of an active-producing well correspond to roughly 7% (or 1 in 13) of all buildings in the state of California, representing a substantial overlap. Importantly, an estimated 673,000 of the 738,000 total exposed buildings are located in residential-type tax parcels, indicating that the majority (over 90%) of these buildings are likely homes, not industrial or commercial buildings. We also observed that 37% of the active-producing wells (30,775) in California are within 1 km (3,281 ft) of at least one residential building.

These residential building counts almost certainly underestimate actual residential housing unit counts in these well areas, because the building data registers multi-unit residences and apartment buildings only as a single building footprint (Microsoft Maps, 2021). This underestimate is also supported by the fact that the total population estimated to live within 1 km (3,281 ft) of a well (n=~3 million) would result in an average person per household value of 4.57 — a value much higher than the actual state estimated average person per household of 2.95. These well-to-building relationships hold for all other buffer distances, with more than 25,000 wells within 2,500 ft (0.76 km) of an estimated 461,246 homes, and 6,564 wells responsible for the 500 ft (152 m) co-locations observed for nearly 45,000 homes. In sum, this analysis supports the census-based population estimates and further highlights California's land use issues where active oil and gas production occurs in many residential urban and suburban areas.

Table 7.5. Sensitive receptors in proximity to at least one of the 83,834 active-producing hydrocarbon wells in California. Percentage (%) represents the percent of total receptors within the respective buffer distance.

Buffer Distance from Wells	Correctional Facilities[1]	Parks[1]	Park Area[1] (mi^2)	Healthcare Facilities[2]	Senior Care Facilities[2]	All Buildings[2]	Residential Buildings[2]
Total Receptors	408	4,983	143.3	2,131	7,246	10,988,525	12,577,497
0–500 ft (0–152 m)	7 (2%)	90 (2%)	0.7 (<1%)	25 (1%)	44 (1%)	55,370	44,994
0–1,000 ft (0–305 m)	9 (2%)	154 (3%)	2.3 (2%)	59 (3%)	118 (2%)	142,480	123,167
0–1,500 ft (0–457 m)	15 (4%)	208 (4%)	4.3 (3%)	87 (4%)	176 (2%)	249,779	221,262
0–2,000 ft (0–610 m)	18 (4%)	276 (6%)	6.5 (5%)	116 (5%)	237 (3%)	373,241	334,816
0–2,500 ft (0–762 m)	21 (5%)	344 (7%)	8.9 (6%)	156 (7%)	324 (4%)	509,785	461,246
0–3,281 ft (0–1,000 m)	28 (7%)	461 (9%)	12.8 (9%)	207 (10%)	466 (6%)	738,467	673,068
0–5,280 ft (0–1,609 m)	55 (13%)	841 (17%)	23.9 (17%)	364 (17%)	832 (11%)	1,373,393	1,260,567

[1]Spatial resolution of receptor was the entire area extent of the land use parcel and was the basis for inclusion in the proximity. "Parks" are instances where any portion of the park intersects with a well buffer. "Park area" is the land area in square miles that intersects with a well buffer.
[2]Spatial resolution of the receptor was the building footprint and was the basis for inclusion in the proximity. Note that the total count for Residential Buildings was referenced from tax parcel data, and therefore includes counts of multi-building unit residences.

Table 7.6. Counts of unique active-producing wells associated with the sensitive receptors in **Table 7.7**.

Buffer Distance from Wells	Counts of wells near Correctional Facilities[1]	Counts of wells near Parks[1]	Counts of wells near Healthcare Facilities[2]	Counts of wells near Senior Care Facilities[2]	Counts of wells near Residential Buildings[2]
0–500 ft (0–152 m)	24	463	287	82	6,564
0–1,000 ft (0–305 m)	96	1,214	587	337	11,969
0–1,500 ft (0–457 m)	159	2,143	865	730	16,933
0–2,000 ft (0–610 m)	242	3,210	1,218	1,210	21,378
0–2,500 ft (0–762 m)	358	3,905	1,609	1,733	25,632
0–3,281 ft (0–1,000 m)	619	4,957	2,377	2,356	30,775
0–5,280 ft (0–1,609 m)	1,375	7,771	4,319	4,591	46,695

[1]Spatial resolution of receptor was the entire area extent of the land use parcel and was the basis for inclusion in the proximity.
[2]Spatial resolution of the receptor was the building footprint and was the basis for inclusion in the proximity.

Table 7.7. Sensitive receptors in proximity to at least one hydrocarbon extraction-related wastewater location in California. Percentage (%) represents the percent of total receptors within the respective buffer distance.

Buffer Distance from Wells	Correctional facilities[1]	Parks[1]	Park Area[1] (mi^2)	Healthcare[2] (ND)[a]	Senior Care[2]	All Buildings[2]	Residential Buildings[2]
Total Receptors	408	4,983	143.3	2,131	7,246	10,988,525	12,577,497
0–500 ft (0–152 m)	1 (<1%)	9 (<1%)	0.1 (<1%)	0 (0%)	4 (<1%)	3,574	926
0–1,000 ft (0–305 m)	2 (<1%)	12 (<1%)	0.4 (<1%)	3 (<1%)	12 (<1%)	11,881	4,982
0–1,500 ft (0–457 m)	4 (1%)	19 (<1%)	0.7 (<1%)	6 (<1%)	21 (<1%)	25,622	13,307
0–2,000 ft (0–610 m)	6 (1%)	33 (<1%)	1.1 (<1%)	10 (<1%)	35 (<1%)	45,053	26,476
0–2,500 ft (0–762 m)	7 (2%)	47 (<1%)	1.7 (1%)	10 (<1%)	59 (1%)	68,837	43,643
0–3,281 ft (0–1,000 m)	7 (2%)	70 (1%)	3.7 (3%)	26 (1%)	91 (1%)	116,186	98,667
0–5,280 ft (0–1,609 m)	16 (4%)	172 (3%)	10.2 (7%)	58 (3%)	201 (3%)	274,098	200,848

[a]ND (No duplicates) indicates that duplicate entities are represented by single feature location.

[1]Spatial resolution of receptor was the entire area extent of the land use parcel. "Parks" are instances where any portion of the park intersects with a well buffer. "Park area" is the land area in square miles that intersects with a well buffer.

[2]Spatial resolution of the receptor was the building footprint. Note that the total count for Residential Buildings was referenced from tax parcel data, and therefore includes counts of multi-building unit residences.

Table 7.8. Schools and higher education facilities near at least one of the 83,834 active-producing wells in California. The number of wells driving the land use co-locations are shown in parentheses next to receptor counts where available. Percentage (%) represents the percent of total receptors within the respective buffer distance.

Buffer Distance from Wells (feet)	Total Schools[1] (Pre-K to 12th Grade) (% total)	Childcare facilities[2]	Total Public Schools[1]	Total Public Schools (ND)[a,1]	Total Private Schools[2]	Total Private Schools (ND)[a,2]	Universities[1] (250+ Campus Housing)	Community Colleges[1]
Total Receptors	22,452	8,867	10,630	10,076	2,955	2,880	118 // 145[b]	116 // 266[b]
0–500 ft (0–152 m)	226 (1%)	68 (1%)	136 (1%)	125 (1%)	22 (1%)	22 (1%)	7 (5%)	3 (1%)
0–1,000 ft (0–305 m)	439 (2%)	122 (1%)	262 (2%)	240 (2%)	55 (2%)	52 (2%)	9 (6%)	8 (3%)
0–1,500 ft (0–457 m)	668 (3%)	218 (2%)	362 (3%)	340 (3%)	88 (3%)	84 (3%)	12 (8%)	12 (5%)
0–2,000 ft (0–610 m)	990 (4%)	336 (4%)	521 (5%)	491 (5%)	133 (5%)	129 (5%)	13 (9%)	14 (5%)
0–2,500 ft (0–762 m)	1,293 (6%)	451 (5%)	657 (6%)	622 (6%)	185 (6%)	178 (6%)	16 (11%)	18 (7%)
0–3,281 ft (0–1,000 m)	1,749 (8%)	659 (7%)	881 (8%)	832 (8%)	269 (9%)	258 (9%)	19 (13%)	23 (9%)
0–5,280 ft (0–1,609 m)	3,245 (14%)	1,262 (14%)	1,498 (14%)	1,421(14%)	485 (16%)	470 (16%)	28 (19%)	36 (14%)

[a]ND (No duplicates) indicates that duplicate entities are represented by single feature location.

[b]Universities and community colleges can often entail places and buildings in distinct geographic locations (e.g., off-campus athletic fields or administrative buildings); we therefore report the total receptors as individual buildings on a campus as opposed to one campus = one receptor. Counts represent any time a well is within the said distance of a building associated with the university or community college.

[1]Spatial resolution of receptor was the entire area extent of the land use parcel.

[2]Spatial resolution of the receptor was the building footprint.

Table 7.9. Counts of unique active-producing wells associated with the sensitive receptor in **Table 7.10**.

Buffer Distance from Wells	Counts of wells near Total Schools[1] (Pre-K to 12th Grade)	Counts of wells near Childcare facilities[2]	Counts of wells near Total Public Schools[1]	Counts of wells near Total Private Schools[2]	Counts of wells near Universities[1]	Counts of wells near Community Colleges[1]
0–500 ft (0–152 m)	865	350	614	126	16	8
0–1,000 ft (0–305 m)	1,654	867	1,290	425	29	55
0–1,500 ft (0–457 m)	2,571	1,555	2,070	808	53	130
0–2,000 ft (0–610 m)	3,327	2,135	2,780	1,150	98	245
0–2,500 ft (0–762 m)	4,344	2,772	3,823	1,656	119	363
0–3,281 ft (0–1,000 m)	6,006	4,046	5,232	2,380	139	639
0–5,280 ft (0–1,609 m)	11,365	8,121	10,107	5,336	405	1,840

[a]ND (No duplicates) indicates that duplicate entities are represented by single feature location.
[1]Spatial resolution of receptor was the entire area extent of the land use parcel.
[2]Spatial resolution of the receptor was the building footprint.

Table 7.10. Schools and higher education facilities in proximity to at least one hydrocarbon extraction-related wastewater location in California. Percentage (%) represent percent of total receptors within the respective buffer distance.

Buffer Distance from Wells	Total Schools[1] (Pre-K to 12th Grade) (% total)	Childcare facilities[2] (% total)	Total Public Schools[1]	Total Public Schools (ND)[a,1]	Total Private Schools[2]	Total Private Schools (ND)[a,2]	Universities[1] (% total) (250+ Campus Housing)	Community Colleges[1] (% total)
Total Receptors	22,452	8,867	10,630	10,076	2,955	2,880	118 // 145[b]	116 // 266[b]
0–500 ft (0–152 m)	12 (<1%)	2 (<1%)	10	9 (<1%)	0	0 (0%)	1 (<1%)	1 (<1%)
0–1,000 ft (0–305 m)	25 (<1%)	4 (<1%)	18	16 (<1%)	3	3 (<1%)	1 (<1%)	1 (<1%)
0–1,500 ft (0–457 m)	49 (<1%)	13 (<1%)	29	27 (<1%)	7	7 (<1%)	1 (<1%)	3 (1%)
0–2,000 ft (0–610 m)	94 (<1%)	30 (<1%)	49	46 (<1%)	15	15 (<1%)	1 (<1%)	3 (1%)
0–2,500 ft (0–762 m)	149 (<1%)	48 (<1%)	81	75 (<1%)	20	20 (<1%)	2 (1%)	4 (2%)
0–3,281 ft (0–1,000 m)	239 (1%)	84 (<1%)	132	125 (1%)	31	30 (1%)	4 (3%)	4 (2%)
0–5,280 ft (0–1,609 m)	611 (3%)	229 (3%)	302	283 (3%)	80	79 (3%)	9 (6%)	9 (3%)

[a]ND (No duplicates) indicates that duplicate entities are represented by single feature location.

[b]Universities and community colleges can often entail places and buildings in distinct geographic locations (e.g., disparate athletic field). We therefore report both the total number of all merged locations (first number), and the total number of individual parcels and buildings (second number). Counts here represent any time a well is within the said distance of any place or building associated with the university or community college.

7.4.4. Density of oil and gas development

Studies of health effects associated with oil and gas development commonly employ two related organizing principles to characterize potential exposures to populations: distance from, and intensity of, oil and gas development (Gonzalez et al., 2020; Johnston et al., 2021; Shamasunder et al., 2018; K. V. Tran et al., 2020). More recently, studies have modeled distance and density simultaneously to capture both proximity and intensity of operations. For example, Gonzalez et al. (2020) used inverse distance-squared weighting of oil and wells in California to study risk of adverse birth outcomes. The exposure metrics that result from inverse distance-squared weighting account for both distance and well density, where an exposure index of 1 is equivalent to having one well located 1 km (3,281 ft) away from the maternal residence or 100 wells located 10 km (6.2 mi) away.

To assess well density and associated population-level characteristics, we adopted methods similar to Shonkoff and Hill (2019), including counting wells within census tract areas to calculate well density (i.e., number of wells per square mile). Shonkoff and Hill (2019) included a 1,000 ft (305 m) buffer area around all census tracts before performing the spatial join with well locations to account for edge effects. We followed this method, and also reported well counts and density without the 1,000 ft buffer areas around each census tract (**Table 7.11**).

Shonkoff and Hill (2019) determined areas of relatively higher well density by first enumerating wells at the census tract level and then grouping or "clustering" adjacent census tracts that met a certain well density threshold (approximately 10 wells/mi^2) that was derived by observing a natural break in the frequency distribution. Here, 10 wells/mi^2 pertains to approximately the 80th percentile statewide when considering the distribution frequency of census tracts that contain wells. We similarly grouped adjacent census tracts that met the threshold of 10 wells/mi^2 to support relative comparisons of well density clusters throughout California (**Table 7.11**).

Of the 83,834 active-producing wells we assessed, 82,676 fell within a census tract boundary because 1,158 wells are located on offshore islands. An estimated 615 census tracts (~8% of census tracts) contain at least one active-producing well, resulting in a mean well density of 2.01 wells/mi^2 (0.78 wells/km^2) across a total area of over 41,000 mi^2 (106,000 km^2). These census tract areas encompass an estimated population of 2.8 million Californians. This population estimate differs from the well-distance estimates because the coincident census tract counting method here does not account for nearby populations that are just beyond census tract boundaries.

To identify areas and neighborhoods that exhibit clustering and relatively higher well densities, all adjacent census tracts that met the 80th percentile were aggregated together and assigned a place name akin to the largest nearby neighborhood or locational identifier. These census tract cluster locations were then ranked and presented alongside numerous population-level metrics available from CalEnviroScreen 3.0[4] (**Table 7.11**) (OEHHA, 2018). Location names were labeled manually by the authors to capture the largest nearby city and note that some neighborhoods may be included within these areas but are not labeled.

Overall, we found that 157 census tracts in 16 areas have a well density of at least 10 wells/ km^2 and 180 census tracts in 23 distinct areas have a well density >10 wells/mi^2. These 16 areas encompass over 628,000 people, and 64 of these 157 census tracts (~40%) have CalEnviroScreen 3.0 scores that designate them as disadvantaged communities with disproportionate socioeconomic, health, and environmental burdens, in addition to the burdens associated with upstream OGD. Because a quarter of all California census tracts are designated as disadvantaged communities based on CalEnviroScreen scores, this finding indicates that disadvantaged communities are overrepresented (1.6 times more likely) in census tracts that contain ≥10 wells/km^2 These communities may include, but are not limited to:

- Areas disproportionately affected by environmental pollution and other hazards that can lead to negative public health effects, exposure, or environmental degradation.
- Areas with concentrations of people with low income, high unemployment, low levels of home ownership, high rent burden, sensitive populations, or low levels of educational attainment.

The highest mean well density was observed in the Los Angeles cluster location, where an area just over 5 mi^2 (13 km^2) contains 866 active-producing wells. This results in a mean well density of nearly 200 wells/mi^2 (77 wells/km^2). The area also has the highest population density in the state, with over 112,000 of California's residents — the majority of which reside in disadvantaged communities per CalEnviroScreen 3.0. Notably, the maximum well density value is in a downtown Los Angeles census tract, with 51 active producing wells within an area of 0.06 mi^2 (0.15 km^2). These results agree with Shonkoff and Hill (2019) — the population density within Los Angeles is significantly higher than most places studied in the peer-reviewed literature of oil and gas activity and health outcomes. This suggests that any hazards or emissions from oil and gas activity in Los Angeles could impact a relatively large number of people.

[4] CalEnviroScreen 3.0 was the available version of CalEnviroScreen at the time of analysis (OEHHA, 2018). Since that time, an updated version, CalEnviroScreen, 4.0, was released.

Table 7.11. Analysis of locations with the highest oil and gas well densities within California.

Location	Well count	Well count (including 1,000 ft buffer)	Density (km^2) (including 1,000 ft buffer)	Cluster Area Mean Well Density (km^2)	Total Population	Census Tract Counts	Total Disadvantaged Communities	Mean CES 3.0 Percentile	Maximum CES 3.0 Percentile
Los Angeles	866	3,463	76.8	73.3	112,464	34	23	81.1	97
Long Beach	1,317	3,308	32.7	15.6	89,869	25	14	66.6	99
Signal Hill	594	1,368	30.0	29.1	44,228	11	4	64.1	97
Baldwin Hills	661	1,352	29.9	25.8	31,790	7	0	53.3	73
Taft	34,576	35,351	20.6	16.7	15,568	4	2	67.3	80
Newhall	323	550	20.0	20.0	14,407	3	0	38.7	41
Beverly Hills	237	692	16.5	16.6	67,860	18	1	43.5	85
Bakersfield	15,214	15,723	16.0	16.0	32,185	7	4	72.6	81
Huntington Beach	426	642	15.4	17.2	47,751	9	0	19.9	46
Coalinga	126	305	13.9	7.7	5,277	1	0	62.0	62
Seal Beach	153	280	11.8	12.5	15,830	5	0	27.6	65
Ventura	758	897	11.7	8.3	8,371	2	1	68.0	78
Brea	1,029	1,578	11.0	10.7	88,458	16	1	38.6	79
Sante Fe Springs	232	471	10.9	9.4	23,984	6	6	89.5	97
Montebello	149	244	10.7	11.8	15,098	4	3	77.8	86
Athens	87	193	10.7	10.1	14,972	5	5	95.4	99
Total	**56,748**	**66,417**	-	-	**628,112**	**157**	**64**	-	-

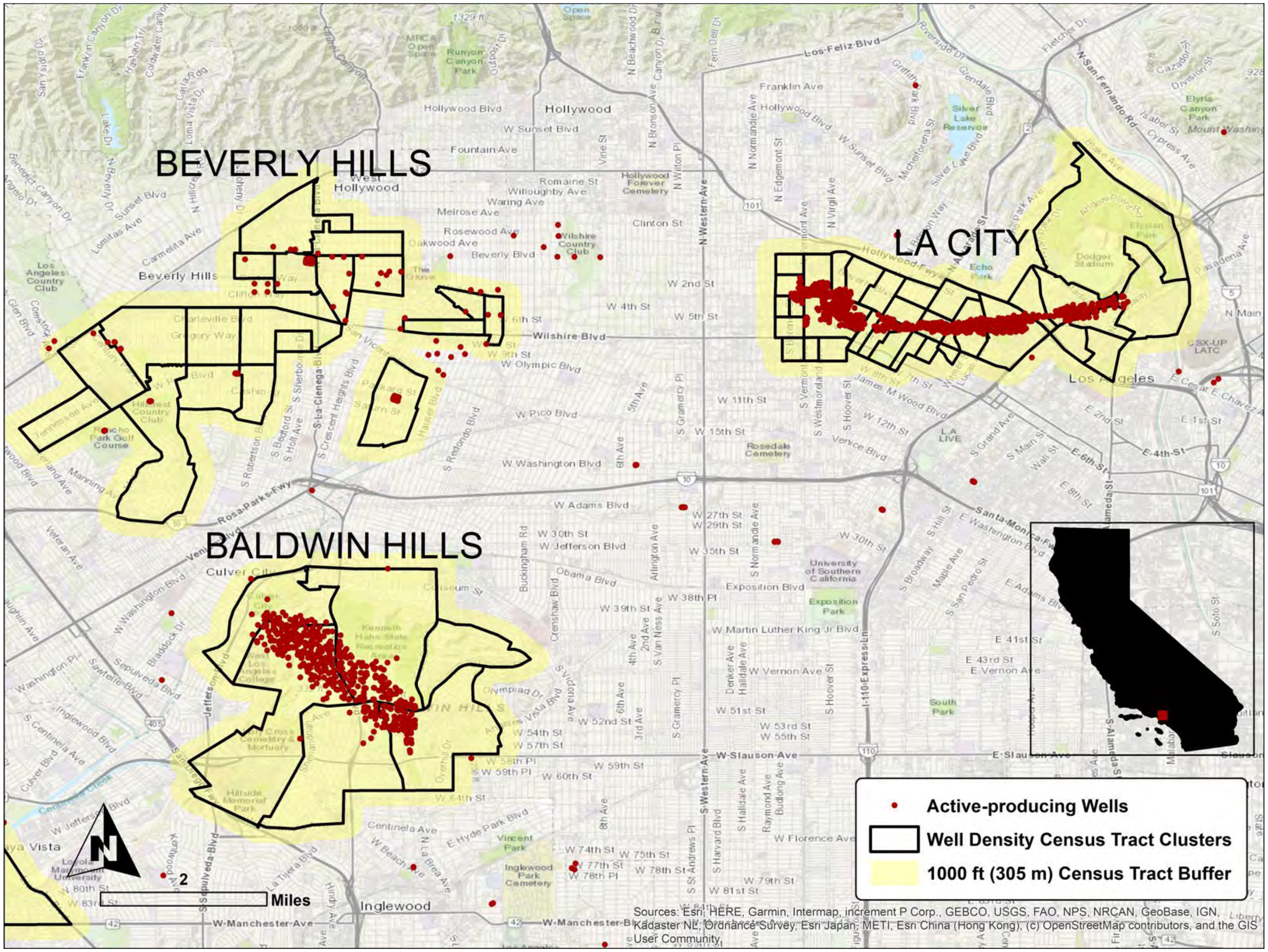

Figure 7.7. Well density near Los Angeles, Baldwin Hills, and Beverly Hills using the coincident wells within census tract method. Outlined census tract areas (black color) indicate areas that exceed 10 wells/km^2. Yellow areas represent the 1,000 ft (305 m) buffer areas around census tracts used to count wells beyond census tract boundaries to reduce the impact of edge effects. Note: Singular name is shown as representing select areas to simplify this visualization; however, these areas are broadly described and include various communities.

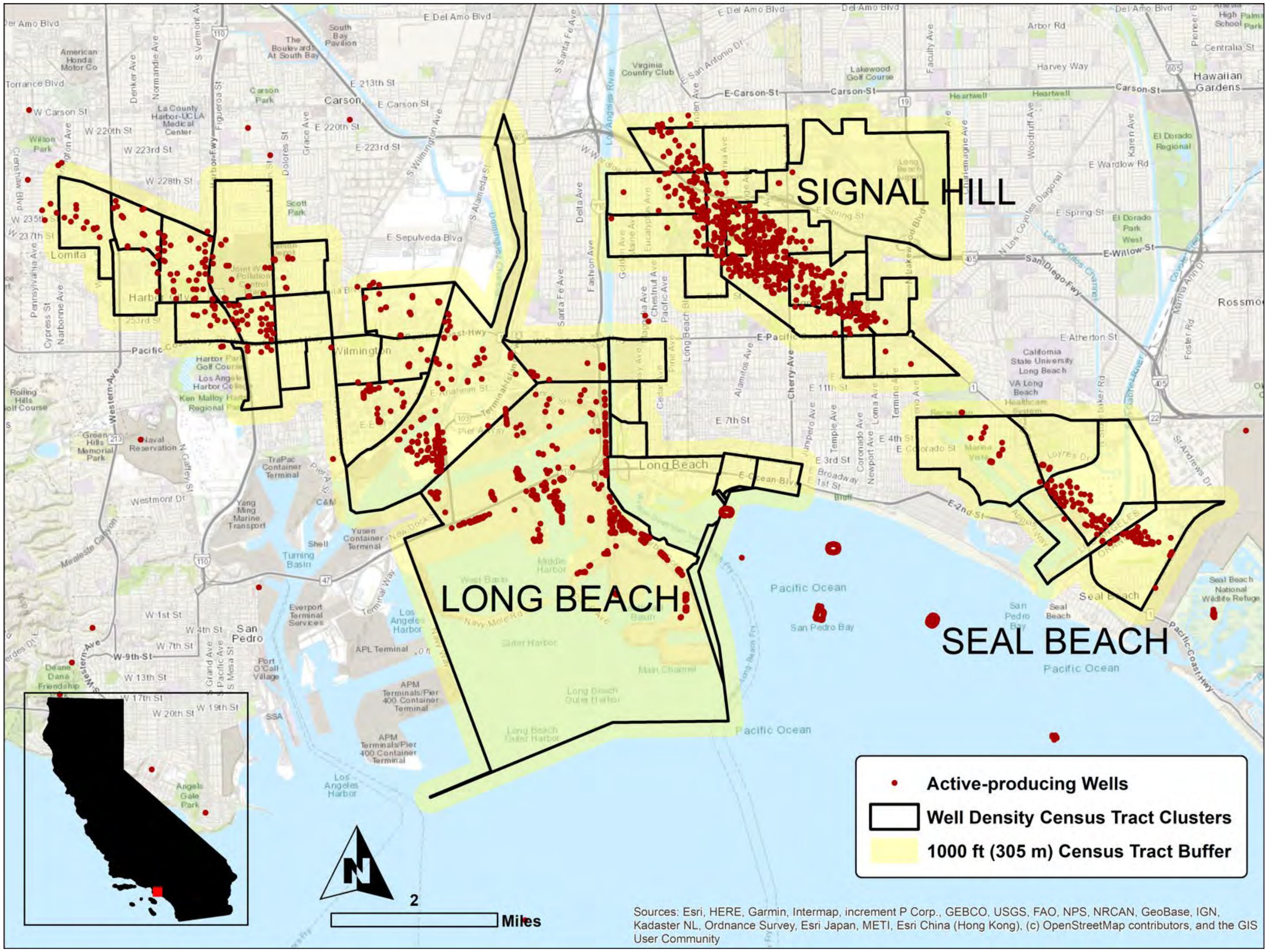

Figure 7.8. Well density near Long Beach (including Harbor City), Signal Hill, and Seal Beach using the coincident wells within census tract method. Outlined census tract areas (black color) indicate areas that exceed 10 wells/km^2. Yellow areas represent the 1,000 ft (305 m) buffer areas around census tracts used to count wells beyond census tract boundaries to reduce the impact of edge effects. Note: Singular name is shown as representing select areas to simplify this visualization; however, these areas are broadly described and include various communities.

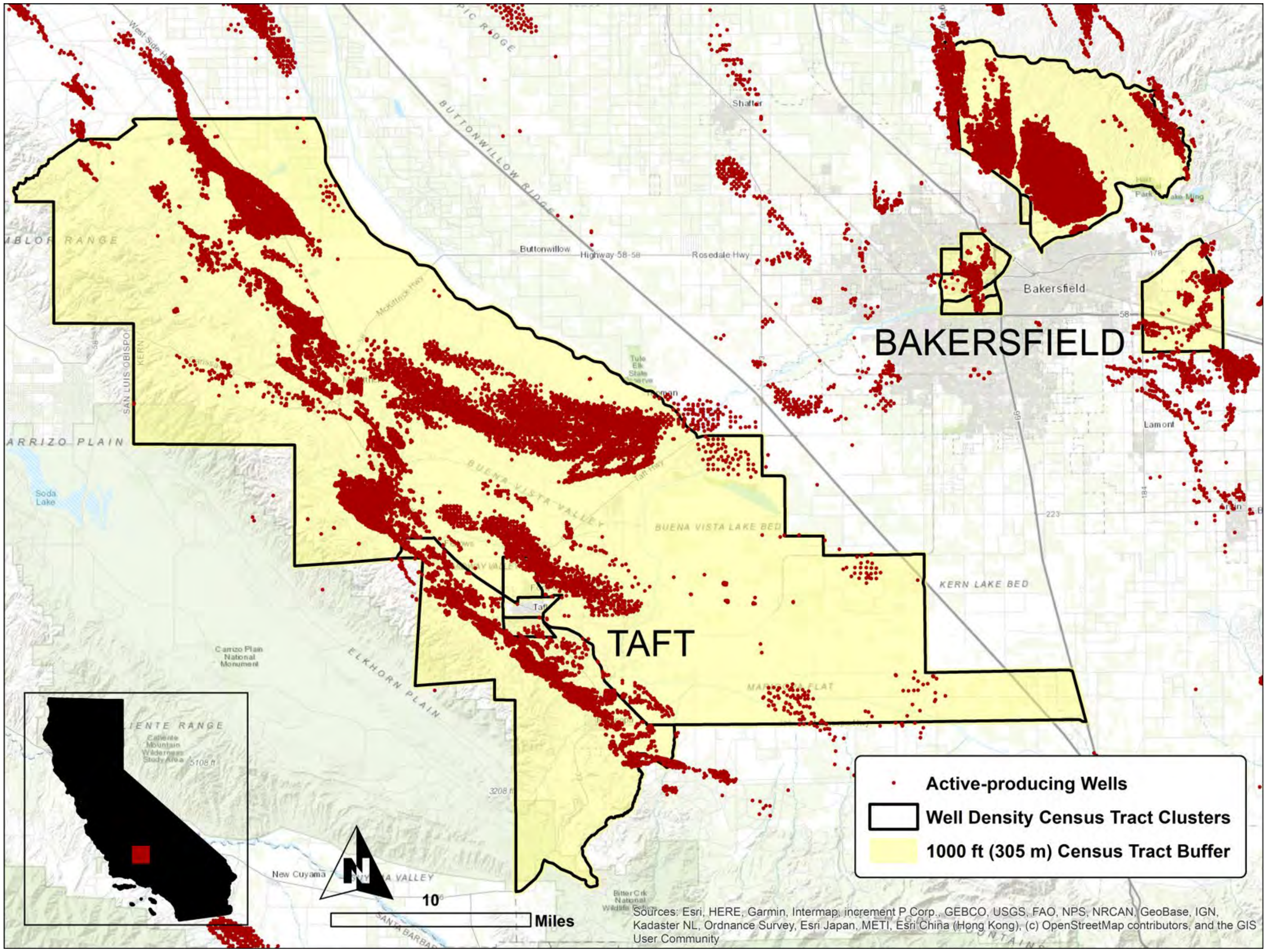

Figure 7.9. Well density near Taft and Bakersfield using the coincident wells within census tracts method. Note the difference in scale compared to **Figure 7.7** and **Figure 7.8**. Also, the Bakersfield location included census tracts that were not directly adjacent. Outlined census tract areas (black color) indicate areas that exceed 10 wells/km^2. Yellow areas represent the 1,000 ft (305 m) buffer areas around census tracts used to count wells beyond census tract boundaries to reduce the impact of edge effects. Note: Singular name is shown as representing select areas to simplify this visualization; however, these areas are broadly described and include various communities.

7.4.5. Hyperlocal proximity: Within 500 feet of oil and gas development

The peer-reviewed literature suggests that closer population proximities to OGD results in greater risks of exposures. While much of the analysis above focuses on providing counts and estimates of populations and receptors within a set of distinct distance thresholds away from wells (e.g., populations living within 1 km [3,281 ft] of active-producing wells), we know that certain hazards follow distinct distance-decays such as noise (Basner & McGuire, 2018; Broner, 2010; Hays et al., 2017) and air pollution (see Chapter 4). With the advancement of geospatial mapping and satellite imagery we can now pinpoint precise locations of oil and gas wells, land use parcels, and even individual buildings. By using both the discrete locations of oil and gas wells and residentially zoned buildings, we can determine just how close some California residents live near active oil and gas wells.

Across California, we identified 1,663 active-producing wells (2% of all active-producing wells) that are within 100 ft (30 m) of at least one residentially-zoned building (n=3,661). California State Fire Code regulation § 5706.3 prohibits location of oil and gas wells within 100 ft of any building not necessary to the operation of the well; however, local jurisdictions may amend the regulation (24 Cal. Code Regs. § 5706.3). This number likely is an underestimate, because we limited the count to residentially zoned buildings only. For example, an active well (yellow marker) surrounded by a residential community in Bakersfield (**Figure 7.10**) illustrates the extent to which some Californians live very close to active oil and gas, with one home within 50 ft (15 m) of the well and many others within 100 ft (30 m). It also helps to further contextualize the counts of populations (**Table 7.3**) and residential buildings within 500 ft (152 m) of wells (**Table 7.5**).

Figure 7.10. Active-producing well (yellow marker) near Bakersfield depicting the hyperlocal proximity to nearby homes (tan color). Radial distances from the well are depicted in red approximately 50 ft and 100 ft from the wellhead. Distances between buildings and their nearest well as shown here were used to create the frequency histogram as shown in **Figure 7.11**.

Thousands of homes in California are located in very close proximity to OGD (**Figure 7.11)**. For example, more than 21,000 residential buildings are within 300 ft (91 m) of at least one active-producing well (**Figure 7.11a**, blue dashed line). Thus, approximately 2,200 wells technically meet California's "critical well" status, being located with 300 ft (91 m) of a residential building. Moreover, in reference to the California Fire Code (24 Cal. Code Regs. § 5706.3.1.3), there are ~4,100 residential buildings within 100 ft (30 m) of an OGD well (**Figure 7.11a**, red dashed line); however, some jurisdictions have been amended to include exceptions. Note that residential buildings are represented once though they may have multiple wells within 500 ft (152 m). From a public health standpoint, these hyperlocal co-locations of homes and wells likely represent areas of increased risk of adverse exposure from OGD operations and should be priority candidate areas for reducing the associated public health and safety burdens faced these communities.

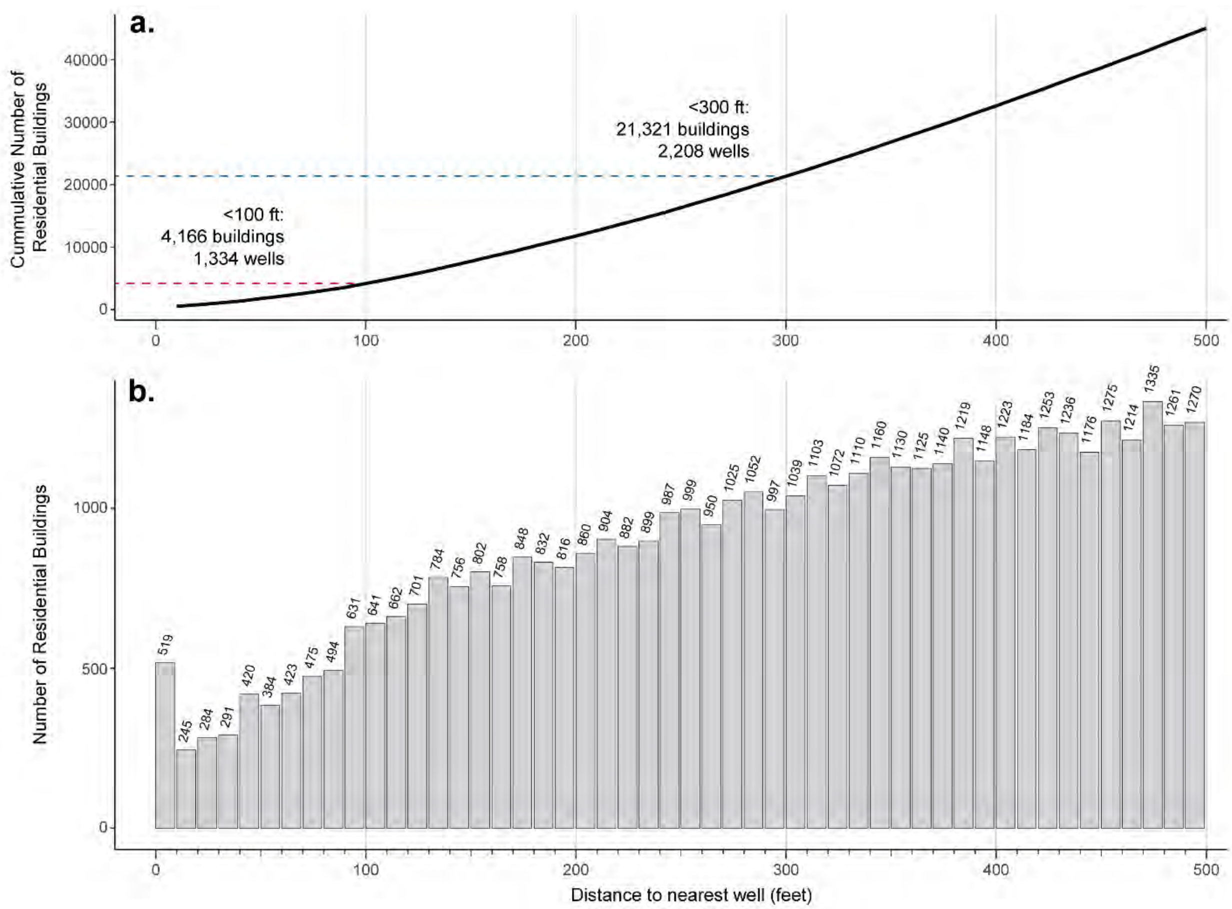

Figure 7.11. Frequency histogram of cumulative counts (a) and binned counts (b) of residential buildings binned by distance to their nearest active-producing oil and gas well from 0–500 ft (0–152 m). The blue dashed line indicates the 300 ft (91 m) distances that demarcates California's "critical well" status. Note: residential buildings are represented once though they may have multiple wells within 500 ft (152 m).

7.5. Discussion

The goals of this California proximity analysis were to provide:

1. Tangible metrics that contextualize the associated public health and safety burdens of communities in proximity to existing oil and gas activity.
2. A comparison of spatial relationships to inform future minimum surface setback regulations for new extractive activities, and identify the associated populations benefitted by various setback distances.
3. New information that is particularly unique to California regarding how close some homes and residents are to oil and gas development.
4. Assessment of existing racial and socioeconomic inequities to determine whether oil and gas development (OGD) is more likely to be located in proximity to disadvantaged communities in California.

To inform these goals, we first investigated the state of the science related to population allocation methodologies and related geospatial techniques. We also incorporated several other content areas to inform our OGD proximity analysis. These included the findings and conclusions presented in previous chapters of this report, previous proximity analyses performed in California, existing surface setback and well siting location regulations in California and throughout the United States, and distributional inequities observed within the peer-reviewed literature across a range of disciplines (**Figure 7.1**). Summation of these topics were presented in the Background and Justification section. Our analytical results were structured into four main interrelated sections:

1. Racial and socioeconomic disparities and estimated total populations in proximity to oil and gas development;
2. Sensitive receptors in proximity to oil and gas development;
3. Density of oil and gas development; and
4. Hyperlocal proximity: Within 500 (152 m) feet of oil and gas development.

The proximity analysis we conducted largely overcomes the common areal unit weighting problem, particularly for downscaling population data in more rural areas by using novel, highly spatially resolved population information in the form of Census blocks, residential tax parcels, and building footprints. In the United States, population data are publicly available at aggregated areal units (e.g., census blocks, census tracts), and represent "nighttime populations," that is, areas where people reside, not necessarily reflective of daytime exposures related to school, occupation, or other activities. However, conducting proximity analyses using area-level population estimates, as in the current analysis, necessitates assumptions about the spatial distribution of populations within that area. Typically, researchers assume that populations are uniformly distributed within aerial units (proportional weighting). This tenuous assumption is a form of the modifiable areal unit problem. Studies that rely on census data or similar data to estimate populations at sub-census area scales are constrained by the modifiable areal unit problem that can lead to bi-directional errors that increase as search areas become smaller (Michanowicz et al., 2019). Because the built environment is not homogenous but is highly variable, the goal in downscaling aggregated census information (e.g., to the building level) is to capture only habitable land uses. This was done using residential parcels from the California Air Resources Board (CARB) parcel data, census population at the block group and block-levels (from 2013–2017 and 2010, respectively) and building footprints from Microsoft's U.S. buildings dataset.

Therefore, this proximity analysis is novel in our application of population and sociodemographic data resolved at the sub-block level (Depsky et al., 2022). As this assessment utilized a novel dasymetric dataset, no other OGD proximity analysis included in our review contained population data at this fine of a resolution. Compared to less spatially precise methods, this method is particularly helpful for determining more accurate estimates of populations living near OGD.

Our criteria for identifying active oil and gas locations in California resulted in the inclusion of 83,834 "active-producing" wells and a total of 2,977 wastewater disposal features. Notably, 95% of OGD in California is located within three CARB-defined air basins, and it is clear that the clustering of wells in some areas has important implications for public health. This analysis also includes numerous demographic and contextual variables and key sensitive receptors at the building footprint and area extent resolutions such as schools, healthcare facilities, and residentially zoned buildings. Finally, with use of individual building footprint locations, we assessed hyperlocal proximities between homes and wells at distances less than 500 ft (152 m).

While we attempted to utilize the most spatially accurate data available, healthcare facilities and senior care facilities locations were limited to point locations that were later manually joined to nearest building locations. This process may have resulted in misclassification of facility locations if, for example, the matched building footprints were not accurate. Additionally, using the extent of building footprints (the spatial feature we used to determine proximity to wells) may have led to underestimates of the physical spaces where people spend time near buildings. For example, most schools have outdoor areas, such as playgrounds and athletic fields, where students spend time. In the context of regulatory setback distances for sensitive receptors, special consideration should be given to these frequently occupied outdoor spaces that extend beyond the building walls. Therefore, a more encompassing setback approach would entail a receptor boundary defined at a parcel boundary or property line, rather than a building structure to anchor the setback distance.

Across the landscape of OGD in California, we observed proximity disparities by race/ethnicity and by indicators of socioeconomic marginalization including residing in linguistically-isolated households, living in a renter-occupied residence, and relatively low educational attainment (i.e., no high school diploma). Non-Hispanic Black people are 87% more likely to reside in areas that contain OGD within 1 km (3,281 ft) compared to non-Hispanic white populations in California. These results were supported by the well density analysis where we found that disproportionately high well densities exist in previously identified disadvantaged communities throughout California, based on assessments in CalEnviroScreen 3.0.

Inequities in exposure to environmental pollution have been well documented in California (Morello-Frosch, 2002; Pastor et al., 2006). Such inequities arise due to historic and current development patterns, regulatory frameworks, and environmental racism (Balazs & Ray, 2014; Bullard, 2011). While causal links between environmental pollution exposure from individual sources and adverse health effects can be difficult to establish due to methodological challenges and etiological limitations (Morello-Frosch, 2002), a large body of evidence has demonstrated the connection between proximity to significant pollutant sources and health risks (Bergstra et al., 2018; Linder et al., 2008). Such fence line communities tend to be disproportionately lower income and Black, Indigenous, and people of color, and these trends have been previously observed in California, further supporting the population-level inequities observed herein (Balazs et al., 2011; OEHHA, 2018; Pastor et al., 2006). Most recently, Gonzalez et al. (2022) found that across the United States, the siting of oil and gas wells was associated with historic redlining practices, which could help explain, in part, the racial and socioeconomic disparities in proximity to wells reported in our proximity study. Redlining encompasses the historic and persistent racist policies in housing, lending, and urban planning policies. Briefly, following the Great Depression, the U.S. federal government established the Home Owners' Loan Corporation (HOLC) and the Federal Housing Administration (FHA), which directed widespread neighborhood appraisals to determine investment risk, referred to as "redlining," that took into account residents' race. The authors found that, across the 33 included cities, redlined D-graded neighborhoods had an average of 12.2 ± 27.2 wells/km^2, which was nearly twice the density of wells in neighborhoods graded A or "Best"

(6.8 ± 8.9 wells/km^{-2}). These findings were consistent in Los Angeles and may account for the disproportionate siting of OGD in racially marginalized neighborhoods observed in the present day.

A large number of sensitive receptors such as schools, healthcare facilities, senior care facilities, parks, etc., are also in proximity to at least one (and often many) active oil and gas wells or wastewater locations. However, it is important to note that though counts of sensitive receptors require only one nearby well at a certain search distance, a portion of receptors contain multiple nearby wells, and in some cases, very high nearby well densities. For example, 21 healthcare facilities have more than 100 active-producing wells within 1 km (3,281 ft), and 14 facilities have more than 200 — all of which are located in the City of Los Angeles. Similarly,107 schools have over 100 wells within 1 km (3,281 ft), with 33 schools surrounded by over 300 wells within 1 km (3,281 ft), the majority of which are also located in the City of Los Angeles. From a public health standpoint, the Los Angeles area represents a unique combination of higher well density and high population density that does not exist in other parts of the United States.

The other major finding related to OGD and proximity to sensitive receptors is that these land use co-locations are driven, in part, by only a small fraction of the total active-producing well inventory in California. Even greater disproportionate well-to-receptor distributions were observed at increasingly shorter buffer distances. Notably, all schools and well co-locations at the 1 km (3,281 ft) distance could be eliminated by addressing just 7% of California's total well inventory. Overall, these disproportionate well-to-receptor counts have important implications for informing policy and present an opportunity to realize significant risk reductions by addressing only a small proportion of existing well sites.

Considerable land use co-locations between populations and OGD were also observed for wastewater locations. An estimated 400,000, or roughly 1 in 100 (1%), California residents live within 1 km (3,281 ft) of an active produced water disposal pond and any status water disposal well. Within this distance lie an estimated 99,000 residentially zoned buildings, 239 pre-K through 12th grade schools, 91 senior care facilities, and 26 healthcare facilities. With the relative lack of knowledge pertaining to depositional patterns of pond emissions, it is unknown precisely how many of these receptors are impacted by potential emissions. Moreover, while we do see significant overlap of population dynamics between wastewater and production wells, wastewater facilities do not completely mimic population-level inequities observed for OGD. This result indicates that different populations across California may be disproportionately burdened by various sub sectors of the oil and gas supply chain. From a policy perspective, this observation has implications for understanding the protections that will be afforded to certain subgroups depending upon how and what portions of oil and gas activity are further regulated.

Fluxes of organic compounds emitted from produced water ponds also present a public health risk, but these hazards are poorly characterized. Specifically, only one study has measured organic compound concentrations in emissions from produced water ponds in California (Schmidt & Card, 2020). Summary statistics for all detected constituents within this study, and a discussion of knowledge gaps of airborne emissions are provided in Chapter 5, Section 5.5.3. Because this study did not measure transport distances of these compounds, the exact area affected by these detected emissions is unknown. Similarly, other studies (Lyman et al., 2018; Mansfield et al., 2018; Thoma, 2009; H.N.Q. Tran et al., 2018) have measured concentrations of organic compounds in emissions from produced water ponds in other states, but these studies also do not include a distance component to their measurements. As such, the associated exposures to proximal populations from these compounds is relatively unknown.

The scientific consensus from peer-reviewed studies strongly suggests that the public health risks and impacts from exposure to upstream oil and gas activity increase as a function of distance from oil and gas development and nearby well density. The science is sufficiently clear that the development of oil and gas immediately adjacent to places where people live, work, play and learn poses hazards and risks to public health, and that a minimum surface setback distance between sensitive receptors and oil and gas sources should be considered. While California does indeed maintain both a forward- and reverse setback regulation for oil and natural gas wells in relation to nearby buildings based upon the California Fire Code, the 100–300 ft setback distances are the least stringent of all major oil and gas producing states and therefore has likely contributed to the significant numbers of Californians that currently live in proximity to OGD. Existing regulatory setback distances from wells to residences, including those established in California, may not be adequate to reduce human health risks, and a more robust, statewide setback policy is needed.

7.6. Summary

An estimated 3 million (8%) California residents live within 1 km (3,281 ft) of at least one active-producing[5] oil and gas well. Based on satellite imagery, an estimated 670,000 residentially zoned buildings, or 6% of all California buildings, are within 1 km (3,281 ft) of at least one active-producing well. Many sensitive receptors, such as schools, childcare facilities, healthcare facilities, senior care facilities, correctional facilities, and parks, are also located in close proximity to oil and gas development in California **(Table 7.12)**.

The observed close proximity between active-producing oil and gas wells and sensitive receptors like schools and healthcare facilities are driven by a small fraction of the total active-producing wells in California. For example, an estimated 6,006 active-producing wells (7.2% of all wells) are within 1 km (3,281 ft) of at least one school. Similarly, 2,377 wells (~3% of all wells) are responsible for all of the co-location with healthcare facilities at the 1 km (3,281 ft) distance.

An estimated 1,663 active-producing wells are within 100 ft (30 m) of at least one home (n=3,661 homes). California State Fire Code regulation 24 C.C.R. § 5706.3 prohibits location of oil and gas wells within 100 ft of any building not necessary to the operation of the well; however, local jurisdictions may amend the regulation.

[5] Active-producing oil or gas wells were defined as *active* if reported as active, new, or idle and *producing*. i.e., a well that was part of a class where at least 1% of wells of that type produced hydrocarbons, indicating that the well was capable of producing.

Table 7.12. Residents and sensitive receptors in proximity to at least one of the 83,000 active-producing oil and gas wells in California, January 2021.

Buffer Distance	Number of Residents	Under 5 years old	Over 64 years old	Schools (pre-K to 12th grade)	Child-care Facilities	Health-care Facilities	Senior care Facilities	Correct-ional Facilities	Parks	Residential Buildings
Statewide Total	**38,984,806**	**2,698,315**	**5,352,812**	**22,452**	**8,867**	**2,131**	**7,246**	**408**	**4,983**	**12,577,497**
500 ft (152 m)	219,681	15,110	30,959	226	68	25	44	7	90	44,994
1,000 ft (305 m)	590,116	39,476	82,984	439	122	59	118	9	154	123,167
1,500 ft (457 m)	1,032,255	68,909	143,807	668	218	87	176	15	208	221,262
2,000 ft (610 m)	1,551,743	103,736	212,905	990	336	116	237	18	276	334,816
2,500 ft (762 m)	2,123,961	141,733	287,705	1,293	451	156	324	21	344	461,246
3,281 ft (1 km)	3,080,713	205,027	412,674	1,749	659	207	466	28	461	673,068
5,280 ft (1.6 km; 1 mile)	5,772,699	384,810	760,877	3,245	1,262	364	832	55	841	1,260,567

The statewide analysis of parcel and census data (2015–2019 American Community Survey) shows that the proportions of Hispanic, non-Hispanic Black, and non-Hispanic Asian people, linguistically isolated households, renters, individuals without a high school diploma, and populations with household incomes below two times the federal poverty line were higher in areas within 1 km (3,281 ft) of at least one active-producing well compared to the overall proportion of each of these groups in California. Additionally, compared to non-Hispanic White Californians, non-Hispanic Black Californians are 87% more likely to reside within 1 km (3,281 ft) to at least one active-producing oil and gas well. Similarly, the proportion of Hispanic Californians living within 1 km (3,281 ft) of at least one active-producing oil and gas well is 42% higher than non-Hispanic White people.

Findings indicate that compared to non-Hispanic White and more socioeconomically advantaged populations, non-Hispanic Black, non-Hispanic Asian, Hispanic populations, and those of lower socioeconomic status were more likely to live near upstream oil and gas development activities where exposures to stressors are likely to be higher.

Many California communities contain a high density of wells, and a disproportionate number of these communities are designated as disadvantaged**.** Among California's 8,057 census tracts, 157 (1.9%) contained 10 or more wells per square kilometer. Sixty-four of these 157 census tracts (~41%) have a CalEnviroScreen 3.0 (OEHHA, 2018) score that designates them as a disadvantaged community with disproportionate socioeconomic, health, and environmental burdens, in addition to the burdens associated with upstream oil and gas development. Because a quarter of all California census tracts are designated as disadvantaged communities based on CalEnviroScreen scores, this finding indicates that disadvantaged communities are overrepresented (1.6 times more common) in census tracts that contain 10 or more wells per square kilometer.

Active-producing wells in California are often spatially clustered, with 95% located in just three Air Basins. Spatial clustering or high well density suggests that proximity to one well likely means proximity to many wells. For example, 21 healthcare facilities have more than 100 active-producing wells within 1 km (3,281 ft), and 14 facilities have more than 200. Similarly, 107 schools have over 100 wells within 1 km (3,281 ft), with 33 schools are surrounded by over 300 wells within 1 km (3,281 ft).

An estimated 400,000 California residents live within 1 km (3,281 ft) of an active produced-water disposal pond and any-status water-disposal well.[6] Within this distance are an estimated 98,700 residentially zoned buildings, 239 schools (pre-K through 12th grade), 91 senior care facilities, and 26 healthcare facilities. Emissions of volatile organic compounds (VOCs) have been measured from produced water ponds in California; however, the distances that these compounds travel and their corresponding atmospheric concentrations have not been assessed. Moreover, publicly available data on drinking water well spatial locations in California are unreliable. This

[6] Wells designated as 'Water Disposal' in CalGEM 'All Wells' dataset (CalGEM, 2021).

hinders the ability to evaluate risk of drinking water contamination from subsurface migration of fluids from produced water disposal processes.

Exemption and conditional exception mechanisms reduce the effectiveness and public health protections of minimum surface setbacks between oil and gas development operations and receptors. In other states, exemptions, variances, and consent waivers provide opportunities to avoid or weaken well-siting requirements, and therefore have resulted in setback distances that vary widely in practice. The effectiveness of minimum surface setback policies depends not only on the required setback distance, but also on the exemptions that are permitted.

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Appendix F

F.1. Proximity Analysis Study Area and Data Sources

F.1.1. Study area

The geographic focus of this study is the entire state of California. Using GIS techniques, all datasets were limited to the boundaries of the state of California. Some analyses were aggregated by air basin, county or by census tract. All geospatial analyses were performed using the California Teale Albers projection.

F.1.2. Oil and gas data

Oil and gas wells

The following oil and gas well datasets were provided by CalGEM on January 21, 2021, and were used for all analyses:

1) CalGEM "All Wells" file (current as of January 21, 2021).
2) CalGEM "2010 Present Production Injection Volumes" — gas, oil, water quarterly production (2010–2020).

These datasets were used to identify wellhead locations and well status, type, and quantitative production volumes. While oil and gas extraction in California is supported by numerous well types in various operating conditional states (i.e., status), our well inclusion criteria were aimed to capture wells that are capable of producing hydrocarbons at the time of writing this report. Therefore, to provide these "active-producing" wells and their locations for the proximity analysis, the two datasets listed above were first joined by American Petroleum Institute (API) well number — a unique identifier allowing for common examination across individual well status, type and hydrocarbon production activity over the past ten years. For the "active-producing wells", data were refined so that all wells included in the analysis were, according to CalGEM, *active, new, or idle* statuses as of January 21, 2021 (**Table F.1**).

Because not all well types routinely produce oil or gas, we next examined proportions of wells by type that have produced any oil or gas within the past six years. We selected a 1% cut-off value for the well type inclusion criteria, meaning that at least 1% of wells within a certain well type must have produced hydrocarbons over the past five years to be included in the proximity analysis. If a well type met these criteria, all wells of that type that were also status *new, active, or idle* were included in the final well dataset. **Table F.2** shows these percentages in the far-right column, with rows highlighted in green indicating well types that were included in the "active-producing" well dataset. Note that the well type "gas" did not meet the 1% threshold but was still included due to its likelihood to function as a producing well akin to "dry gas" and "oil and gas" well types.

Table F.1. All-type hydrocarbon-related extraction wells by well status as of January 21, 2021. Rows in light grey indicate consideration for inclusion in proximity analysis. Note: some wells can produce both oil and gas.

Status	Well Count	Oil Producing Wells 2015–2020	Gas Producing Wells 2015–2020	Wells Included by Well Status
Plugged	126,400	1857	988	
Active	60,937	45,041	25,808	60,937
Idle	38,557	9,435	5,589	38,557
Canceled	8,991	9	6	
New	5,426	712	347	5,426
Plugged Only	177	12	6	
Unknown	111	1	0	
Abeyance	1	0	0	
Total	**240,600**	**57,067**	**32,744**	**104,920**

The final well selection criteria (**Figure F.1**) resulted in a final well count of 83,834. Notably, 206 wells reported duplicate well locations even though no duplicate API numbers were present. In some cases only the API number differed. In other cases, well status or well type differed, indicating that the same well may have been repurposed to a subsequent operating type. However, no well activity dates were provided within this dataset to test this hypothesis. It is also possible that two wells exist on the same well pad but were geolocated to the same well pad centroid location. Irrespective of cause, duplicate well locations were removed to not double count proximate populations or sensitive receptors.

Figure F.1. Well dataset selection criteria and the resulting final count. Note: 206 wells reported duplicate well locations. To not double count populations and sensitive receptors, these duplicates were removed resulting in a final "active" well count of 83,834.

Table F.2. All-status hydrocarbon-related extraction wells by well type with counts and proportion of producing wells. Rows in light grey indicate consideration for inclusion in proximity analysis.

Well Type	Well Count	Oil Producing Wells 2015–2020	Gas Producing Wells 2015–2020	Oil or Gas Production 2015–2020	Percent of Producing Wells 2015–2020	Wells Included by Type
Oil & Gas	157,426	39,782	27,702	40,117	25.48	157,426
Cyclic Steam	21,000	16,529	3,658	16,531	78.72	21,000
Dry Hole	16,743	0	0	0	0.00	
Steamflood	12,605	71	4	71	0.56	
Waterflood	11,170	86	60	86	0.77	
Dry Gas	5,003	134	1,187	1,187	23.73	5,003
Observation	4,857	21	11	21	0.43	
Multi-Purpose	2,922	215	73	216	7.39	2,922
Water Disposal	2,295	7	0	7	0.31	
Injection	1,705	1	0	1	0.06	
Core Hole	1,451	0	0	0	0.00	
Gas	1,418	0	3	3	0.21	1,418
Unknown	952	84	42	84	8.82	952
Gas Storage	451	135	3	137	30.38	451
Water Source	248	1	0	1	0.40	
Pressure Maintenance	141	1	1	1	0.71	
Gas Disposal	115	0	0	0	0.00	
Air Injection	92	0	0	0	0.00	
Liquefied Gas	6	0	0	0	0.00	
Total	**240,600**	**57,067**	**32,744**	**58,463**		**189,172**

Oil and gas wastewater disposal infrastructure

Locations of produced water were compiled from three sources:

1. Latest (January 31, 2019) State Water Resources Control Board (SWRCB) Produced Water Pond Status Report (SWRCB, 2019),
2. Pits and sumps dataset in the California Geologic Energy Management Division's (CalGEM) WellSTAR Statewide Tracking and Reporting System (CalGEM, 2018), and
3. Locations of ponds provided in the SWRCB's Geotracker system (SWRCB, 2021).

Occasionally, locations of ponds in Geotracker were provided in the Public Land Survey System notation (e.g., section, township, range). In these cases, the California utility of Earth Point in Google Earth was used to determine the centroid in latitude and longitude of the section, township, and range. Since there was no common shared key between all three of the datasets, ponds in each dataset were joined by the latitude and longitude values in R to create a compiled dataset (R Core Team, 2020). The compiled dataset was then imported into ArcGIS 10.8.1, and duplicated features were joined manually by comparing to multiple years (2009, 2014) of high-resolution (~1 m, 3.3 ft) aerial imagery (CDFW, 2009, 2014). After the removal of duplications, there were a total of 2,389 pond features remaining which were considered in the statewide proximity analysis. Of these features, only those with a status of "active" (n=682) were joined to all wells with a type of "Water Disposal" (n=2,295) from the CalGEM "All Wells" dataset (CalGEM, 2021). This combined dataset (2,977 features) was then used in the proximity analysis to characterize populations living within proximity to oil and gas wastewater infrastructure.

F.1.3. Population data

California statewide parcel data

Tax assessor real estate land parcel data were obtained from the California Air Resources Board (CARB) for the entire state of California. These parcel data included land use types (e.g., single-family residential) and were used to distinguish between residential and non-residential parcels for use in downscaling Census block data to these high-resolution parcel areas. Population data available at the census block-level was downscaled to these residential-type parcels using a proportional distribution method further described in the "populated areas" methods section below.

Population and demographic data

U.S. Census blocks were utilized for all population and demographic information. Unfortunately, the most recent block-level population information was enumerated from the 2010 decennial census. To provide more recent population estimates, block group-level data in the ongoing five-year American Community Survey (ACS) was utilized. Block-level populations from the 2010 decennial census were extrapolated forward in time using population estimates from the 2013–2017 ACS for parent block-groups; proportional distribution of population amongst the blocks within each block group was kept constant according to patterns observed in 2010, but with updated totals to reflect values in the ACS dataset.

F.1.4. Sensitive receptors data

Building footprint data

Geospatial building footprint data were available from Microsoft, which provides deep learning generated building footprint vectors for the entire United States, representing the built environment as of June 2018 (Microsoft Maps, 2021). In addition to supporting the population model, building locations were also used to represent sensitive receptors where spatial resolution of administration data was available only as single points. This applied to private school locations, daycare locations, all healthcare facilities, and senior care facility locations. To assign these point data to building geometries, we employed the near function to capture the nearest building followed by a spatial join to append the sensitive receptor attributes to the nearest building geometry. In some cases, the underlying point data represents multiple entities, such as multiple healthcare facilities. This also resulted in duplicate building geometries following the near and join functions. Therefore, we present counts of sensitive receptors both with and without duplicates as indicated by the “ND” notation, indicating “no duplicates” and any duplicate co-located entities equaling n=1.

CalEnviroScreen 3.0

CalEnviroScreen 3.0[7] is a screening tool that identifies communities most affected by and vulnerable to the effects of many sources of pollution and population-based disparities (OEHHA, 2018). It aggregates statewide environmental, health, and socioeconomic information to produce scores for every census tract in the state. A census tract with a high score is considered more disadvantaged than a community with a low score as a result of pollution burden and population characteristics. When overlaid with climate impact and exposure data, CalEnviroScreen can provide insight into built and environmental exposure factors that contribute to vulnerability (Mohnot et al., 2019; OEHHA, 2018).

Schools and childcare facilities

The California School Campus Database provided land parcel location data for all California Public Schools kindergarten through 12th grade as well as all California Community College campuses and University land parcel locations that are believed to house at least 250 students on campus (GreenInfo Network, 2021). Private school locations were available from California Department of Education Open Data (CDE, 2021).

Correctional facilities

Correctional facilities were available from the Homeland Infrastructure Foundation — a provision via the federal Department of Homeland Security (Oak Ridge National Laboratory, 2020). Facilities included within this database range from federal (excluding military) jurisdiction to local

[7] CalEnviroScreen 3.0 was the available version of CalEnviroScreen at the time of analysis (OEHHA, 2018). Since that time, an updated version of CalEnviroScreen (4.0) was released.

governments. These features are represented by polygon geometry that "describes the extent of where the incarcerated population is located (fence lines or building footprints)."

Parks and playgrounds

Area locations of parks and playgrounds were derived by combining spatial data from three datasets:

- Real estate tax parcels provided by CARB; park parcels were identified by "use code."
- The California Protected Areas Database, a dataset maintained and updated by the Greeninfo Network (GreenInfo Network, 2018) that captures open space lands, parks, conservation easements, and preserves statewide.
- USA Parks, a geospatial dataset produced by ESRI in partnership with TomTom, a private company specializing in location technologies and digital geodatabase products and services (ESRI, 2019). This layer is considered to be ESRI's "authoritative" data on parks, gardens and forests, combined with boundary information for national, state and local parks.

When compared to current (2018) aerial imagery, it is apparent that some parks are represented by polygons in two or more of these data layers. It is also apparent that no one dataset is sufficiently comprehensive to be used alone to represent parks and sensitive land uses for this project. From these three data layers, a single composite and validated dataset was produced by using aerial imagery to identify each candidate site ("parks and playgrounds" as defined by CARB in their Air Quality and Land Use Handbook) and selecting from each layer the polygon(s) that best represent that site visible in the aerial imagery. The aerial imagery was also used to determine which of these parks qualify as a site, using the presence of improvements such as athletic facilities, play structures, etc.

Health care facilities

Individuals with pre-existing medical conditions, such as people admitted in hospitals and other healthcare facilities, are more prone to developing air pollution-related illnesses (CARB, 2005). Point locations for health care facilities were available from California Health and Human Services, updated as of March 12, 2021, and accessed March 27, 2021, (CalHHS, 2021). Facilities include California's licensed/certified facilities that are currently operating as per the most recent update. The source of the data is provided via the State of California Electronic Licensing Management System (ELMS). Point locations were spatially joined to the nearest building footprint (Microsoft Maps, 2021) to provide representation at the building boundary.

Senior care facilities

Senior care facilities, such as nursing homes, are considered sensitive land uses, as individuals within these types of facilities are the most vulnerable to health risks from exposure to harmful air pollutants (CARB, 2005). Individuals older than 64 years of age are more susceptible to air pollution-related illnesses such as stroke, asthma, heart disease, lung cancer, and other respiratory diseases. Point locations for elder care facilities were available from the California Department of Social Services, updated as of December 2020 and accessed March 27, 2021

(CDSS, 2020). Point locations were spatially joined to the nearest building footprint (Microsoft Maps, 2021) to provide representation at the building boundary.

F.2. Methods to Determine Populations and Sensitive Receptors in Proximity to Oil and Gas Activity

F.2.1. Search-area buffer distances

To quantify populations and sensitive receptors in proximity to oil and gas development (OGD), search areas around OGD sites must be defined at the outset. Selection of radial buffer distances were informed by epidemiological studies of adverse health effects associated with living in proximity to active OGD and previous proximity analyses performed in the U.S. Within these considerations, a range of radial distances around wells were selected to both fully characterize spatial relationships and to support comparison across distances. The selected buffer distances are listed below and represent the radial areas around oil and gas features (i.e., active-producing oil and gas wells, and active produced water ponds and all-status water disposal wells):

- 500 ft (152 m)
- 1,000 ft (305 m)
- 1,500 ft (457 m)
- 2,000 ft (610 m)
- 2,500 ft (762 m)
- 3,281 ft (1 km)
- 5,280 ft (1 mile, 1,609 m)

Geodesic buffers were created in ArcGIS 10.8.1. Individual buffers around features were dissolved to produce one buffer encompassing all features (e.g., the 500 ft [152 m] buffer around wells encompasses all of the area in the state of California within 500 ft [152 m] of an active-producing oil and gas well). These buffers were then intersected with the population area polygons in ArcGIS 10.8.1, to determine the proportion (ranging from 0–1) of each population area polygon falling within the examined buffer distance. Details of how these proportions were calculated are provided in the following area-weighted metrics section.

F.2.2. Downscaling Census population data

In the United States, population data are publicly available at aggregated aerial units (e.g., census blocks), and represent “nighttime populations.'' This population data type is useful, as census surveys capture where respondents reside, rather than time spent working and traveling. Unfortunately, when these data are used for analyses like counting populations, the nature of these spatially aggregated data can lead to bi-directional errors and decreasing accuracy with decreasing search areas (Michanowicz et al., 2019). Studies that rely on census data or similar data to estimate populations at sub-census area scales are constrained by the modifiable areal unit problem and therefore are required to make assumptions about the spatial structure of populations — typically the assumption that populations are homogeneously distributed within aerial units (i.e., proportional weighting).

In essence, the goal in downscaling aggregated census information is to capture only habitable land uses. This was done using residential parcels from the CARB parcel data, census population at the block group and block-levels (from 2013–2017 and 2010, respectively) and building footprints from Microsoft's U.S. buildings dataset. The final map of population using these data was made in the following steps:

1. Extrapolate block-level populations from the 2010 decennial census forward in time using population estimates from the 2013–2017 ACS for parent block-groups. Proportional distribution of population amongst the blocks within each block group was kept constant according to patterns observed in 2010, but with their totals updated to reflect values in the ACS dataset.
2. Identify residential parcels from the CARB parcel data using the "USE_CODE_2" classification, which has some 278 unique land use types, of which 30 were identified as being residential (e.g., "Single Family Residential" and "Apartment House (5+units)"). We also included "planned residential unit developments" because many of these parcels have already been developed, as evidenced by recent satellite imagery.
3. Create a spatial polygon layer of only residential parcels.
4. Of this parcel subset, identify those residential parcels that likely contain a large amount of open, unpopulated space. This was defined as individual parcels with an area of more than 1 acre (0.4 hectares) for low-density residential classes (e.g., "single-family residential") or with more than 50 acres (20 hectares) for high-density residence classes (e.g., "apartment house (100+ units)"). The distinction in thresholds between low- and high-density residence types was made due to the observation that for most low-density uses, parcels may be large but only contain a small portion where a home is located and for which people likely are present., leading to the 1-acre (0.4-hectares) cutoff. However, in densely populated regions, it is common to see single parcels encompass large apartment or condominium developments that can span large areas of urban space, leading to the 50-acre (20-hectares) area cutoff for these parcels.
5. Assume that all parcels not excluded in step 4 (<1 acre or <50 acre areas, <0.4 or <20 hectares), are populated areas, with population distribution assumed to be uniform within each individual parcel. These parcel areas account for roughly 91.8% of the state's total population.
6. For those parcels excluded in step 4 (>1-acre or >50-acres, >0.4 or >20 hectares), identify the buildings within these parcels using the Microsoft U.S. buildings layer, and assume that the population within these large parcels is distributed only amongst the building areas within it. These areas account for roughly 4.9% of the population.
7. For any blocks with a non-zero population but containing no residential parcels, identify buildings within them and assume population is distributed in these buildings. These areas represent roughly 3.0% of the population.
8. Finally, for any blocks with non-zero population but which contain neither residential parcels nor buildings, simply assume that its population is uniformly distributed across the entire block area. This pertains to blocks containing only roughly 0.3% of the population.
9. Using a combination of these four polygon geometries: 1) small residential parcels; 2) buildings within large residential parcels; 3) buildings within populated blocks with no

residential parcels; and 4) boundaries of populated blocks with no residential parcels or buildings); create a polygon layer representing the union of all of them and assign the block level population totals only to these areas within each block, assuming uniform population density throughout the block.

Table F.3. Geographic scales of population data used in proximity analysis (Source: Depsky, University of California, personal communication, 2021).

Step	Data Used for Residential "Footprint"	Share of CA Pop.
1	**Residential parcels** less than 1 acre (0.4 hectares) in area, or less than 50 acres (20 hectares) for parcels with high-density residential use codes (e.g., apartment complexes, condos, etc.).	91.8%
2	**Building areas** within residential parcels excluded in Step 1 (area >1 acre [0.4 hectares] or area >50 acre [20 hectares] for high-density parcels). Located generally in sparsely populated or mixed-use areas.	4.9%
3	**Building areas** within populated blocks with no residential parcels present. Located generally in sparsely populated or mixed-use areas.	3.0%
4	**Entire block areas** for blocks with no residential parcels nor buildings detected. Located generally on small street segments or rural/open areas.	0.3%

Resulting from this process, the geographic scale of the population data used in this analysis was primarily (>90%) at the tax assessor real estate parcel level, with the remainder primarily at building-level (**Table F.3**).

F.2.3. Area-weighted metrics to determine proportions of populated areas and populations in proximity to oil and gas activity

To determine the demographic makeup of populations living within the selected well-area buffer distances, we weighted all metrics of interest by the intersection area of the well-area buffer and the population area polygon (**Figure F.2**).

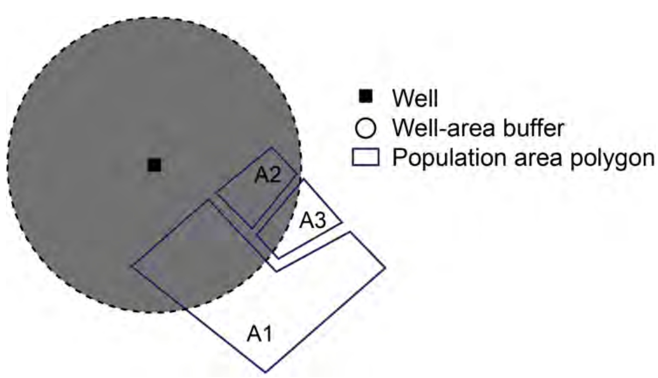

Figure F.2. A visual representation of area-weighting.

In this example, 100% of the population within polygon A2 would be assigned to the well-area buffer, and portions of the population corresponding to the ratio of the shaded area to the total polygon area for polygons A3 and A1 would be assigned to the well-area buffer. Mathematically this corresponds to:

$$Area\ weighted\ Metric\ =\ (Intersection\ Area/Total\ Area)\ x\ Metric\ of\ Interest$$

where $Intersection\ Area$ is the area of the well-area buffer that intersects a population area polygon, $Total\ Area$ is the total area of a population area polygon, and $Metric\ of\ Interest$ is the metric of interest (e.g., proportion of people over 64 years old).

For demographic metrics only, the area-weighted population was multiplied by the demographic metric of interest (e.g., percent of people aged younger than five years old). After calculating the individual area weighted value for each intersection area, values were aggregated over the entire buffer distance by taking either the sum or mean of all values. Different aggregating functions were applied on a per demographic indicator basis in R (**Table F.4**) (R Core Team, 2020).

While area-weighting functions likely introduce bias to population aggregation calculations via their inherent assumptions (i.e., populations are uniformly distributed over the spatial units of interest), the high-resolution population area data we use in our analyses should greatly minimize these biases. Specifically, as previously discussed, non-habitable areas (e.g., roadways, industrial areas) have been painstakingly eliminated from the population area polygons dataset we use for our analyses, and thus edge effects should be greatly reduced, if not eliminated completely.

Table F.4. Functions used to aggregate values for each demographic metric.

Demographic Metric	Aggregation Function	Demographic Metric	Aggregation Function
Under 5 years old	Sum	non-Hispanic White	Sum
Over 64 years old	Sum	Hispanic	Sum
No high school diploma	Sum	non-Hispanic Black	Sum
Voters	Sum	non-Hispanic Asian	Sum
Linguistically isolated households	Sum	non-Hispanic American Indian	Sum
Unemployed	Sum	non-Hispanic other	Sum
Below 2x federal poverty line	Sum	non-Hispanic people of color	Sum
Renter	Sum	Median Household Income	Mean

F.2.4. Calculating demographic group risk ratios

Population weighted demographic group specific risk ratios were calculated to compare the relative risk for each examined demographic group where:

$$Group\ Risk\ Ratio = \frac{\frac{\Sigma Population_{group\ within\ buffer\ area}}{\Sigma Population_{group\ within\ CA}}}{\frac{\Sigma Population_{total\ within\ buffer\ area}}{\Sigma Population_{total\ within\ CA}}}$$

Where $\Sigma Population_{group\ within\ buffer\ area}$ is the total population of a demographic group living within a buffer area (e.g., total number of Californians over 64 living within 3,281 ft (1 km) of an active-producing well), $\Sigma Population_{group\ within\ CA}$ is the total population of a demographic group within the entire state of California (e.g., total number of Californians over 64), $\Sigma Population_{group\ within\ CA}$ is the total population living within a buffer area, and $\Sigma Population_{total\ within\ CA}$ is the total population of California (~39 million people). Risk ratios provide a way to quantify the relative risk of any group. Groups who experience a relatively higher amount of risk will have risk ratios greater than 1, and those that experience the same amount of risk as the general population will have ratios equal to 1.

F.2.5. Counts of sensitive land uses

Sensitive land uses in proximity to oil and gas wells and wastewater systems were enumerated using the same well-area buffer distances to determine intersection or overlap between well-areas and a sensitive land use.

F.3. Community Vulnerability Metrics and Justification for Inclusion

F.3.1. CalEnviroScreen 3.0 (CES 3.0)[8]

This statewide tool provides information regarding environmental health indicators at the census tract levels across the entire state. Commissioned and maintained by the California Environmental Protection Agency (CalEPA) and, more specifically, the Office of Environmental Health Hazard Assessment (OEHHA), this database serves as a tool for information transfer and environmental screening at the community level. The newest iteration of this product, version 3.0, incorporates a wide array of pollution, demographic and socioeconomic metrics to estimate cumulative environmental burdens facing communities. This product is widely used both by policymakers, practitioners, academics, and community organizations in order to identify and implement policies that are sensitive and responsive to environmental inequities.

Cumulative burdens are reported in terms of raw scores (ranging from roughly 0 to 95.0), which are calculated via a multi-step algorithm that incorporates the multiple factors considered, as well as in percentile terms (ranging from 0–100), which provides a relative measure of burden experienced by a given community compared to the rest of the state. Both the raw scores and

[8] CalEnviroScreen 3.0 was the available version of CalEnviroScreen at the time of analysis (OEHHA, 2018). Since that time, an updated version of CalEnviroScreen (4.0) was released.

percentiles were provided in this analysis and may each be appropriate for use in assessing community vulnerability, depending on the context of the research being done or questions being asked. Using the raw scores will provide a true reflection of the actual cumulative burden experienced by each census tract, while using percentiles will only provide a relative measure. Using a simplified example, suppose there are only ten tracts in the state, three of which have a score of 30.0, one of which has a raw score of 80.0, and the remaining six with scores of 95.0.

F.3.2. Racial Composition

Analysis of racial and ethnicity-based metrics is commonly done when assessing issues of community vulnerability and environmental equity/justice more broadly. Given the legacy of segregation, inequality, and marginalization of communities of color in the United States, they are often disproportionately exposed to hazards, environmental and otherwise. There is a very strong precedent for including such metrics in environmental health and community vulnerability studies, especially in the last three to four decades.

F.3.3. Healthcare and senior care facilities

Senior centers and medical facilities such as hospitals, health clinics, and nursing homes are all considered sensitive land uses, as individuals within these types of facilities are the most susceptible to health risks from exposure to poor air quality. Individuals older than 64 years of age are more susceptible to air pollution-related illnesses such as stroke, asthma, heart disease, lung cancer, and other respiratory diseases. Similarly, those individuals with pre-existing medical conditions, such as those people admitted in hospitals and other healthcare facilities, are more prone to developing air pollution-related illnesses (CARB, 2005).

F.3.4. Parks

Park are sensitive land uses in which populations uniquely susceptible to environmental hazard exposures, including children and older adults, are likely to spend time. While parks bring health benefits through facilitating outdoor physical activities, performing physical activities in polluted environments also has adverse health effects. Therefore, reducing potentially hazardous exposures to pollution in parks can ensure their net health benefits.

F.3.5. Correctional Facilities

Compared with the general population, individuals in correctional facilities tend to have higher rates of underlying health conditions, including higher odds of chronic (e.g., asthma, cardiovascular disease, arthritis, and cancer) and infectious diseases (e.g., HIV, hepatitis, and tuberculosis), and mental disorders. By virtue of being incarcerated, individuals in correctional facilities have little to no control over their living conditions and are also likely to have inadequate access to health care. Furthermore, individuals in correctional facilities are faced with poorer living conditions such as overcrowding, which in turn leads to the prevalence of infectious diseases and mental disorders. These conditions can make this community uniquely susceptible to the adverse health effects of environmental hazard exposures.

F.3.6. Schools and Daycares

Children are sensitive to pollution given their small size, high metabolic rates, and developing lung structure and immune systems. In addition to health consequences, air pollution may cause some students to be absent from school, leading to other social cost (e.g., school dropout, parents missing work, and cuts in attendance-based school funding). For children with respiratory issues, not going to school on a heavily polluted day is either a result of respiratory problems triggered by air pollution or a preventive measure. Since children spend more time indoors, their exposures are strongly correlated with pollution concentration in schools and home environments and during transportation.

F.4. Comparison of Buffer Areas

In general, most water disposal infrastructure is sited relatively close to active-producing oil and gas wells. Consequently, buffers extended from active produced water ponds and/or disposal wells overlap with buffers extended from active-producing wells. This overlap ranges from roughly 70% to 90% of the total area encompassed by a water feature buffer, and the overlap area generally increases with increasing buffer distance (**Table F.5**). As such, at best, only 30% of the area of any water feature buffer is unique to produced water disposal infrastructure.

The relatively large amount of overlap between water infrastructure buffers and active-producing well buffers means that a relatively large amount of sensitive receptors in proximity to water disposal infrastructure are already encompassed by buffers extended from active-producing oil and gas wells. For example, 611 schools in California are within one mile (1,609 m) of a water disposal feature. However, only 79 of these schools do not fall within the area encompassed by the one-mile buffer extended from active-producing wells (**Table F.6**). This number corresponds to less than 0.5% of the schools in California. Similarly, this trend exists at the smallest buffer distance (500 ft, 152 m), albeit less pronounced. Specifically, 12 schools are located within 500 ft (152 m) of a water feature, and 10 (<0.1% of the state total) of them are not located within the 500 ft (152 m) buffer extended from active-producing wells (**Table F.6**). As a result, the discussion of sensitive receptors in proximity to oil and gas related features is largely focused on those in proximity to active-producing wells, whose buffers largely encompass areas covered by buffers extended from wastewater disposal features.

Table F.5. Comparison of overlap between water disposal infrastructure and active-producing well buffer areas.

Buffer Distance	Area of water disposal infrastructure buffer (mi^2)	Area of water disposal infrastructure buffer intersecting well buffer (mi^2)	% Overlap
500 ft (152 m)	56.0	41.1	73%
1,000 ft (305 m)	167	115	69%
1,500 ft (457 m)	307	235	77%
2,000 ft (610 m)	465	375	81%
2,500 ft (762 m)	636	530	83%
3,281 ft (1,000 m)	918	789	86%
5,280 ft (1,609 m)	1,689	1,506	89%

Table F.6. Count and percentage of the state total of sensitive receptors unique to water disposal infrastructure for each buffer distance.

Receptor	500 ft (152 m)	1,000 ft (305 m)	1,500 ft (457 m)	2,000 ft (610 m)	2,500 ft (762 m)	3,281 ft (1,000 m)	5,280 ft (1,609 m)	State Total
Correctional Facilities	1 (0.25%)	1 (0.25%)	0 (0%)	1 (0.25%)	1 (0.25%)	1 (0.25%)	4 (0.98%)	408
Parks	6 (0.12%)	6 (0.12%)	12 (0.24%)	14 (0.28%)	19 (0.38%)	20 (0.4%)	21 (0.42%)	4,983
Healthcare Facilities	0 (0%)	0 (0%)	1 (0.05%)	2 (0.09%)	2 (0.09%)	3 (0.14%)	1 (0.05%)	2,131
Senior Care	1 (0.01%)	5 (0.07%)	7 (0.1%)	10 (0.14%)	18 (0.25%)	25 (0.35%)	21 (0.29%)	7,246
All Buildings	1,535 (0.01%)	3,193 (0.03%)	5,778 (0.05%)	9,113 (0.08%)	12,440 (0.11%)	18,551 (0.17%)	32,808 (0.3%)	10,988,525
Total Schools	10 (0.04%)	13 (0.06%)	16 (0.07%)	21 (0.09%)	35 (0.16%)	42 (0.19%)	79 (0.35%)	22,452
Community Colleges	1 (0.38%)	1 (0.38%)	2 (0.75%)	2 (0.75%)	2 (0.75%)	1 (0.38%)	0 (0%)	266
Universities	1 (0.69%)	1 (0.69%)	1 (0.69%)	0 (0%)	0 (0%)	2 (1.38%)	2 (1.38%)	145

F.5. Population and Demographic Counts Within Between-Buffer Areas

Table F.7. Between-buffer area specific total counts and associated demographic metrics of populations living in proximity to active-producing wells.

	0–500 ft (0–152 m)	**501–1,000 ft (153–305 m)**	**1,001–1,500 ft (306–457 m)**	**1,501–2,000 ft (458–610 m)**	**2,001–2,500 ft (611–762 m)**	**2,501–3,281 ft (763–1,000 m)**	**3,281–5,280 ft (1,001–1,609 m)**
Total Population	219,700	370,400	442,155	519,488	572,218	956,752	2,691,986
Age Based							
under 5 years old	15,110	24,366	29,433	34,827	37,997	63,294	179,783
over 64 years old	30,959	52,025	60,823	69,098	74,800	124,969	348,203
Racial							
non-Hispanic White	65,646	118,332	137,796	157,748	170,816	287,847	777,316
Hispanic	90,842	155,498	192,379	230,391	254,331	433,778	1,282,385
non-Hispanic Black	17,745	30,488	38,761	47,639	51,000	76,714	196,350
non-Hispanic Asian	42,687	56,756	62,430	70,661	81,384	134,730	369,239
non-Hispanic American Indian	1,056	1,329	1,616	1,868	2,040	3,390	9,811
non-Hispanic other	7,238	11,562	13,342	16,060	17,709	28,932	80,538
Economic							
below 2x federal poverty line	78,089	126,835	156,300	186,872	209,646	349,814	1,016,800
unemployed	11,905	18,657	22,831	26,743	29,672	51,146	145,846
Education							
no high school diploma	44,978	73,334	90,648	109,427	122,091	208,251	611,258
Miscellaneous							
voters	143,407	243,310	290,714	339,645	372,770	621,840	1,762,552
renters	129,440	196,278	223,770	265,667	293,753	490,812	1,416,473
linguistically isolated households	11,794	15,488	18,135	21,454	23,122	38,841	113,739

Table F.8. Between-buffer area specific total counts and associated demographic metrics of populations living in proximity to active produced water disposal ponds and any water disposal wells.

	0–500 ft (0–152 m)	**501–1,000 ft (153–305 m)**	**1,001–1,500 ft (306–457 m)**	**1,501–2,000 ft (458–610 m)**	**2,001–2,500 ft (611–762 m)**	**2,501–3,281 ft (763–1,000 m)**	**3,281–5,280 ft (1,001–1,609 m)**
Total Population	7,058	26,195	46,846	69,555	87,267	165,542	621,151
Age Based							
under 5 years old	624	1,787	3,191	4,827	6,481	11,796	43,409
over 64 years old	1,147	3,857	6,641	9,712	11,566	22,423	77,436
Racial							
non-Hispanic White	2,672	10,881	19,632	28,930	36,639	69,203	230,212
Hispanic	2,499	8,878	16,456	23,333	29,438	60,498	264,672
non-Hispanic Black	922	2,426	3,532	5,363	5,883	10,197	42,384
non-Hispanic Asian	1,031	3,456	5,977	9,986	12,880	21,273	68,396
non-Hispanic American Indian	120	161	291	356	429	808	2,677
non-Hispanic other	393	1,109	1,881	2,624	3,305	5,809	19,584
Economic							
below 2x federal poverty line	2,128	7,343	13,447	20,175	24,736	49,241	216,371
unemployed	533	1,375	2,390	3,567	4,606	8,669	33,804
Education							
no high school diploma	1,215	4,103	7,338	10,670	13,828	27,990	128,966
Miscellaneous							
voters	4,876	17,743	31,938	47,452	58,823	112,766	407,369
renters	3,094	11,439	20,631	31,785	39,869	74,238	310,946
linguistically isolated households	307	871	1,368	2,144	2,603	5,149	21,569

F.6. Residential Parcels

We utilized a comprehensive, statewide shapefile of all California parcels obtained from CARB. Each parcel in this dataset has a number of attributes pertaining to various use code classifications which were used to distinguish between residential and non-residential parcels.

The following residential type classifications were included in the final population allocation model and to distinguish residential type buildings as listed in the sensitive receptor counts:

- Apartment house (100+ units)
- Apartment house (5+ units)
- Apartments (generic)
- Cluster home (Residential)
- Comm/OFC/Res mixed use
- Condominium (Residential)
- Cooperative (Residential)
- Dormitory, group quarters (Residential)
- Duplex (2 units, any combination)
- Fraternity house, Sorority house
- Garden Apt, Court Apt (5+ units)
- Highrise apartments
- Homes (retired, handicap, rest; convalescent; nursing)
- Manufactured, modular, pre-fabricated homes
- Misc residential improvement
- Mobile home
- Mobile home park, Trailer park
- Multi-family dwellings (Generic, any combination 2+)
- Planned unit development (PUD) (Residential)
- Quadruplex (4 units, any combination)
- Residential (general) (single)
- Residential common area (Condo/PUD/etc.)
- Residential income (General) (Multi-family)
- Rural residence (Agricultural)
- Single family residential
- Stores & Apartments
- Timeshare (Residential)
- Townhouse (Residential)
- Triplex (3 units, any combination)
- Zero lot line (Residential)

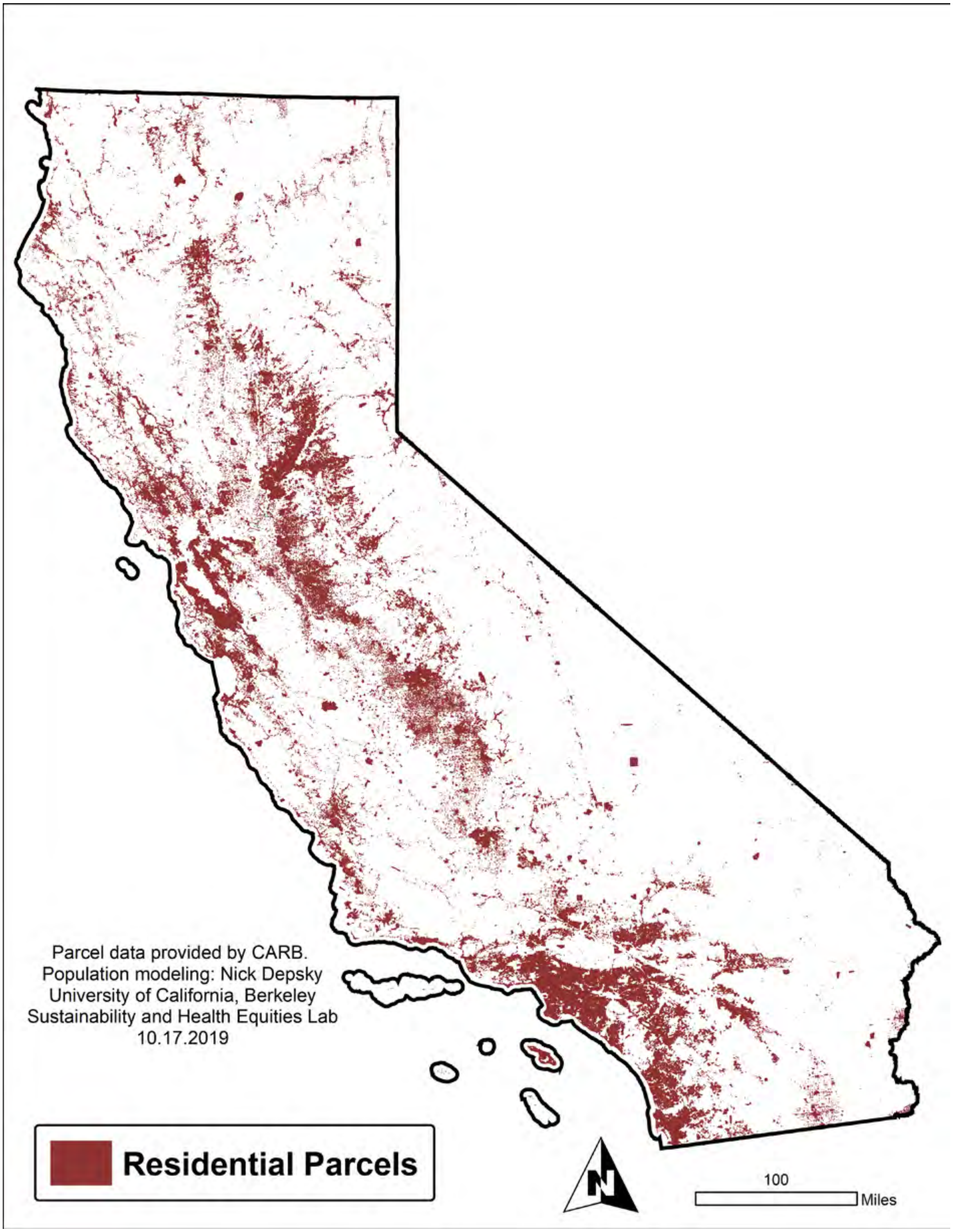

Figure F.3. Residential parcels shown in red utilized to construct the downscaled population model and to determine residential buildings counts.

F.7. Previous California Proximity Analyses

Table F.9. Analyses that have quantified and/or characterized proximity of receptors to oil and gas development in California. Assessments are organized in chronological order of publication.

Proximity Analysis	O&G Sources	Geographic Scope & Receptors	Distance	Data Sources & Years	Key findings
Srebotnjak & Rotkin-Ellman (2014)	Active and new oil and gas wells	California (statewide) Individual residents (no age limitation)	~5,280 ft (1.6 km)	**Well data** (1) DOGGR "All Wells" and "Well Stimulation Treatment Notices Index" (2) SCAQMD "Oil and Gas Wells Activity Notification" (3) the chemicals disclosure registry database FracFocus.org (July 2014) Demographic data (4) CalEnviroscreen 2.0	~5.4 million people (14% of CA population) live within 5,280 ft (1.6 km) of one, or more than 84,000 existing oil and gas wells. ~1.8 million people also live in areas most burdened by environmental pollution; ~1.65 million of these people (92%) are people of color.
Shonkoff and Gautier (2015)	Active oil and gas wells, including stimulated wells	**Los Angeles Basin** **Individuals** (total population, under five y.o, over 75 y.o., children attending school) **Demographics** (race/ethnicity, education, income, employment) **Buildings or zones** (number of schools, elderly care facilities, daycare facilities)	328–6,562 ft (100–2,000 m)	**Well data** DOGGR (All Wells database, SB 4 Well Stimulation Notices, Well Production database); SCAQMD (Rule 1148.2 Oil and Gas Well Electronic Notification and Reporting); FracFocus 1.0 & 2.0 — Accessed 12/14/14, included 2013 and 2014 production wells **Demographic data** U.S. Census (2010) American Community Survey (2013 five-year estimates) **Building/zone data** State of California Geoportal (2014); CA Department of Education (2013/2014 enrollment); CA Dept of Social Services (2014); GreenInfo Network (2012)	In the Los Angeles Basin: ● "approximately 1.7 million people live **within one mile [5,280 ft, 1.6 km]** of an active oil and gas well" ● "130 schools, 184 day care facilities, 213 residential elderly homes and nearly 628,000 residents" are located **within 800 m [2,625 ft]** of an active oil and gas well. ● ">32,000 people live **within 100 m [328 ft]** of an active oil and gas well." ● "while it is clear that oil and gas is being developed in low-income communities and communities of color, there does not appear to be a disproportionate burden of oil and gas development on any one demographic..."
Czolowski et al. (2017)	Active oil and gas wells that produced in 2014	Nationwide; **Demographics** (race/ethnicity, education, income, employment)	328–6,562 ft (100–2,000 m)	**Well data:** Drillinginfo (now Enverus) **Demographic data:** U.S. Census (2010) American Community Survey (2013 five-year estimates)	"...an estimated 2.09 million Californians living **within one mile (5,280 ft, 1.6 km)** of an oil and gas well" On a national level, California was found to have the third highest amount of people (2.1 million) living **within one mile (5,280 ft, 1.6 km)** of an active oil and/or gas well.

Proximity Analysis	O&G Sources	Geographic Scope & Receptors	Distance	Data Sources & Years	Key findings
Earthworks (2016)	Oil and gas wells, compressors and processors	Nationwide; Population estimates, medical facilities, schools and daycares	2,640 ft (805 m)	**Population:** 2010 Census **Schools/Medical:** US Department of Homeland Security's Homeland Infrastructure Foundation-Level Data **Oil and Gas Wells:** Fractracker Alliance, 2016 and 2017 **Compressors and Processors:** EPA Greenhouse Gas Reporting Program, EIA, Oil And Gas Journal, Marchese et al. (2015), EDF, EPA's National Emissions Inventory by the Clean Air Task Force	1,126,071 people live within threat radius **(2,640 ft, 805 m)** in California. 309,135 students in threat radius, 678 schools and daycares within the threat radius. 12,344 childhood asthma attacks. 9,010 lost school days due to oil and gas ozone smog. 1,281 square miles (3,318 square km) of land within the threat radius **(2,640 ft, 805 m)**
Shonkoff and Hill (2019)	Active, inactive, and new oil and gas wells	Greater Los Angeles area; City of Los Angeles Population density, well density	1,000 ft (305 m) (well density)	**Demographic data:** ACS five-year data (2009–2017); **Well data:** California Division of Oil, Gas, and Geothermal Resources (DOGGR) well data - accessed March 2019	**Greater Los Angeles:** "The highest well density in/near the City of Los Angeles is in the Baldwin Hills neighborhood which has **216 wells per square mile** (83 wells per square kilometer)" **City of Los Angeles:** "The highest well density within the City of Los Angeles is in the LA City Neighborhood (Koreatown, Westlake and Chinatown) with **162 wells per square mile** (63 wells per square kilometer)." "Population density is approximately **8,940 people per square mile** (3,430 per square kilometer) throughout the City of Los Angeles and surrounding areas." "The three highest population densities in high well density areas are found in the Jefferson **(22,257 per square mile)**, University Park **(22,237 per square mile)** and LA City (Koreatown, Westlake, and Chinatown) **(21,803 per square mile)** neighborhoods."

Proximity Analysis	**O&G Sources**	**Geographic Scope & Receptors**	**Distance**	**Data Sources & Years**	**Key findings**
Ferrar (2020)	Active oil and gas wells	California (statewide) Individuals, residences, schools, licensed child daycare centers, & healthcare facilities	2,500–5,280 ft (762–1,609 m)	**Well data:** CalGEM "AllWells" file - updated 10/1/2020; CalGEM annual production data; **Demographic data:** American Community Survey (2018 five-year estimates); CalEnviroScreen 3.0; **Building data:** California Health & Human Services; California Department of Education	"approximately 2.17 million Californians live **within 2,500 of an operational oil and gas well,** and about 7.37 million Californians live **within 1 mile"** "California's Frontline Communities living closest to oil and gas extraction sites with high densities of wells are predominantly low-income households with non-white and Latinx demographics." "The majority of oil and gas wells are located in environmental justice communities most impacted by contaminated groundwater and air quality degradation resulting from oil and gas extraction, with high risks of low-birth weight pregnancy outcomes." "Adequate Setbacks for permitting new oil and gas wells will reduce health risks for Frontline Communities."
Shonkoff et al. (2017)	Active underground gas storage (UGS) wells and facilities 2006–2015	Statewide (California) **Individuals** (total population, under five y.o, over 75 y.o., children attending school) **Demographics** (race/ethnicity, education, income, employment) **Buildings or zones** (number of schools, elderly care facilities, daycare facilities)	0–5 miles (0–8 km)	**Well data** Underground gas storage facilities in California by considering storage wells from the 2015 California Division of Oil, Gas, and Geothermal Resources (DOGGR) "All Wells" dataset. **Demographic data** U.S. Census (2010) American Community Survey (2013 five-year estimates) **Sensitive Receptors** These locations consisted of schools (CDE, 2017a; CDE, 2017b; CDE, 2017c), daycare centers (CDE, 2017c; CDSS, 2017a; CDSS, 2017b), residential elderly care locations (CDSS, 2017a), and hospitals (California OSHPD, 2017).	Nearly 1.9 million Californians were estimated to live **within ~5 miles** (8 km) of an underground storage facility A total of 5,585 people were found to be living **within a 0 m buffer** distance of an underground storage facility. Of these Californians, 115,125 are children under the age of five, and 103,085 are adults aged 75 and older Additionally, there were an estimated 1,358 daycare centers, 556 schools, and 359 residential elderly care facilities located **within ~5 miles** (8 km) of an active underground storage facility. 55.9% of the buffer facility combinations had population densities of **≤100 people/km^2** " Population Exposures to Toxic Air Pollutants Increase with Higher Emissions, Closer Community Proximity and Higher Population Density" "UGS facilities pose more elevated health risks when located in areas of high population density, such as the Los Angeles Basin, because of the larger numbers of people nearby that can be exposed to toxic air pollutants."

Proximity Analysis	O&G Sources	Geographic Scope & Receptors	Distance	Data Sources & Years	Key findings
Michanowicz et al. (2019)	Active UGS wells	Six states: PA, OH, WV, MI, NY, CA Individuals & housing units	656 ft (200m) (length of city block)	**Well data** April 2016 Energy Information Administration-191 M Monthly Underground Gas Storage Report **Demographic data** U.S. Census (2010) Building data Housing unit counts, U.S. Census (2010); US Department of Transportation's National Address Database (NAD) (NY, OH) and OpenAddressess.io (PA, WV, MI) originally sourced from state geographic information systems departments, the U.S. Postal Service, and county property parcel datasets (current as of October 23, 2017). Geospatial building footprints and centroids were available via academic use waiver for various parts of the country from BuildingFootprintUSA (BFUSA, Albany, NY).	~65% of underground natural gas storage wells (over 6,000) in the United States are located in residential suburban areas - not commercial, industrial, or even rural areas like many new unconventional wells. 53,000 people across six states are living within **656 ft (200 m) of UGS wells**. 41% of the active UGS wells assessed had **at least one home within 656 ft (200 m).** California: Only 41 of CA's 346 UGS wells (12%) contained **a residential housing unit within 656 ft (200 m)** — the lowest percentage of the six states assessed. This may be an indication that results are not generalizable at the state level, as two wells in the Playa Del Rey field ranked first and third respectively in the number of residential units and population **within 200 m (656 ft).** Of the over 9,000 UGS wells examined in the 6 states, a well in the Playa Del Rey storage field has the most nearby homes and people — **150 homes and 341 people within 200 m (656 ft).**
Ferrar (2021)	Active oil and gas wells	California (statewide) Prisons/detention centers	2,500 ft (762 m)	**Well data:** CalGEM "AllWells" file - updated 10/1/2020 Sensitive receptors California Prison Boundaries from California Office of Emergency Services	Two-thirds (67%) of California prisons (federal, state, county and local) are located within census tracts ranked in the upper 50th percentile of pollution impacted areas. 90% of California's federal prisons are located within census tracts ranked in the upper 50th percentile of pollution impacted areas. Three-quarters (73%) of federal prisons in California are located within census tracts ranked in the upper 30th percentile of pollution impacted areas.

Acronyms and abbreviations

AB	Assembly Bill
ACS	American Community Survey
AEC	annual emissions concentrations
ALAN	artificial lights at night
ALBL	acute lymphoblastic leukemia
ALL	acute lymphocytic leukemia
ANCA	antineutrophil cytoplasmic antibody
APCD	Air Pollution Control District
API	American Petroleum Institute
AQI	air quality index
AQMD	Air Quality Management District
AQMP	air quality management plan
ATSDR	Agency for Toxic Substances and Disease Registry
B	boron
BACT	best available control technology
BARCT	best available retrofit control technology
bbls	barrels
BC	black carbon
BCF	billions of cubic feet
BMI	body mass index
BOE	barrels of oil equivalent
BOPD	barrels of oil per day
Bq	becquerel
BPD	barrels per day
BTEX	benzene, toluene, ethylbenzene, and xylenes
°C	Celsius
C	carbon
CAA	Clean Air Act
CAAQS	California Ambient Air Quality Standards
CalEPA	California Environmental Protection Agency
CalGEM	California Geologic Energy Management Division
CalOES	California Office of Emergency Services
CalWIMS	California Well Information Management System
CAP	criteria air pollutant
CARB	California Air Resources Board
CASRN	Chemical Abstract Service Registry Number
CBM	coalbed methane
CCR	California Code of Regulations
CCST	California Council on Science and Technology
CERCLA	Comprehensive Environmental Response Compensation and Liability Act
CDPHE AQCC	Colorado Department of Public Health and the Environment Air Quality

	Control Commission
CH_4	methane
CIWQS	California Integrated Water Quality System
Cl	chloride
CM	Congenital malformations
CNG	Compressed natural gas
CNGD	conventional natural gas drilling
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalents (methane, carbon dioxide, and nitrous oxide)
COGCC	Colorado Oil and Gas Conservation Commission
COPD	chronic obstructive pulmonary disease
CRC	California Resources Corporation
CWD	Cumulative well density
CVRWQCB	Central Valley Regional Water Quality Control Board
dBA	A-weighted decibels
dBC	C-weighted decibels
DBNPA	2,2-dibromo-3-nitriloprionamide
DBP	disinfection byproduct
DNDW	distance to nearest drilled well
DOGGR	Division of Oil, Gas and Geothermal Resources
DORV	double outlet right ventricle
DPM	diesel particulate matter
$DPM_{2.5}$	fine-diesel particulate matter
DRB	Delaware River Basin
DWSHA	Drinking Water Standards and Health Advisories
EC	electrical conductivity
ED	emergency department
EGDB	Energy Resources Program Geochemistry Laboratory Database
ELG	Effluent Limitation Guideline
EOR	enhanced oil recovery
ESL	effects screening level
°F	Fahrenheit
FEV1	first second of exhalation
FONSI	Finding of No Significant Impact
ft	feet
FVC	forced vital capacity
GHG	greenhouse gas
GHS	Globally Harmonized System of Classification and Labelling of Chemicals
g/s	grams per second
GWPC	Ground Water Protection Council
H_2S	hydrogen sulfide
HAP	hazardous air pollutant
HDAP	health-damaging air pollutant

HF	hydraulic fracturing
HI	hazard index
HQ	hazard quotient
HSC	Health and Safety Code
IA-IDW	Intensity-adjusted inverse distance weighted
IAA	interrupted aortic arch
IARC	International Agency for Research on Cancer
IDW	inverse distance weighted
ICRP	International Commission on Radiological Protection
ISOR	Initial Statement of Reasons
kg/yr	kilograms per year
km	kilometer
L	liter
LACDPH	Los Angeles County Department of Public Health
LAER	lowest achievable emission rate
lbs/day	pounds per day
LBW	low birthweight
LDAR	leak detection and repair
LEL	lower explosive limit
LRTP	long-range transport potential
m	meter
MATES IV	Multiple Air Toxics Exposure Study IV
Mcf	thousand cubic feet
MCL	maximum contaminant level
mg	milligram
mg/L	milligrams per liter
MMbbl	millions of barrels
MPA	migraine probability algorithm
MPO	myeloperoxidase
mSv	millisievert
MRL	minimum risk level
MT	metric tons
N/A	not applicable
N_2O	nitrous oxide
NAAQS	National Ambient Air Quality Standard
NATA	National Air Toxics Assessment
NCATS	National Center for Advancing Translational Science
ND	non detection
NESTAC	National Emission Standards for TACs
NHL	Non-Hodgkin’s lymphoma
NIEHS	National Institute of Environmental Health Sciences
NIH	National Institutes fo Health
NIOSH	National Institute for Occupational Safety and Health
NMVOC	non-methane volatile organic compound

NMHC	non-methane hydrocarbons
NO_2	nitrogen dioxide
NORM	naturally occurring radioactive materials
NOV	Notice of Violation
NO_X	nitrogen oxides
NPDES	National Pollutant Discharge Elimination System
NRDC	Natural Resources Defense Council
NSF	National Science Foundation
NSPS	new source performance standards
NSR	new source review
NTO	Notice to Operator
NTP	National Toxicology Program
O&G	oil and gas
O_3	ozone
OAQPS	(U.S. EPA) Office of Air Quality Planning and Standards
OEHHA	Office of Environmental Health Hazard Assessment
OGD	oil and gas development
OH	hydroxyl radicals
OSHPD	California Office of Statewide Health and Planning
PADEP	Pennsylvania Department of Environmental Protection
PADOH	Pennsylvania Department of Health
PAH	polycyclic aromatic hydrocarbons
PCB	polychlorinated biphenyl
PCE	tetrachloroethene
pCi	picocurie
pCi/L	picocurie per liter
PFAS	per- and polyfluoroalkyl substances
PHMSA	Pipeline and Hazardous Materials Safety Administration
PI	principal investigator
PLSS	Public Land Survey System
PM	particulate matter
$PM_{2.5}$	fine particulate matter with a diameter of 2.5 microns or less
PM_{10}	fine particulate matter with a diameter of 10 microns or less
PMF	positive matrix factorization
POTW	publicly owned treatment works
ppb	parts per billion
ppbv	parts per billion volume
ppm	parts per million
ppmv	parts per million volume
PR3	Persistent proteinase 3
PRISMA	Preferred Reporting Items for Systematic Reviews and Meta-Analyses
PSD	prevention of significant deterioration
PSE	Physicians, Scientists, and Engineers for Healthy Energy

PTFE	polytetrafluoroethylene
QA/QC	quality assurance and quality control
RACT	reasonably available control technology
RCRA	Resource Conservation and Recovery Act
REACH	European Regulation on Registration, Evaluation, Authorisation and Restriction of Chemicals
REL	reference exposure level
RMP	Regional Groundwater Monitoring Program
ROG	reactive organic gas
ROGER	Repository for Oil and Gas Energy Research
SAGE-IGERT	Systems Approach to Green Energy-Integrative Graduate Education and Research Traineeship
SB	Senate Bill
SCAQMD	South Coast Air Quality Management District
scfh	standard cubic feet per hour
SD	standard deviation
SDWA	Safe Drinking Water Act
SE	standard error
SGA	small for gestational age
SIP	state implementation plan
SIR	standardized incidence ratios
SJV	San Joaquin Valley
SJVAPCD	San Joaquin Valley Unified Air Pollution Control District
SNAPS	Study of Neighborhood Air Near Petroleum Sources
SO_2	sulfur dioxide
SOF	Solar Occultation Flux
SO_X	sulfur oxides
SWRCB	California State Water Resources Control Board
TAC	toxic air contaminant
TAPVC	total anomalous pulmonary venous connection
T-BACT	Toxic Best Available Control Technology
TCEQ	Texas Commission on Environmental Quality
TDS	total dissolved solids
TENORM	technologically enhanced naturally occurring radioactive materials
tpd	tons per day
tpy	tons per year
TRI	Toxic Release Inventory
TSCA	Toxic Substances Control Act
UGS	underground gas storage
µg	microgram
µg/l	microgram per liter
$\mu g/m^3$	microgram per cubic meter
µmhos/cm	micromhos per centimeter
µR	microroentgen

µSv	microsievert
UGS	underground gas storage facility
UIC	underground injection control
UNG	unconventional natural gas
UNGD	unconventional natural gas development
UOGD	unconventional oil and gas development
U.S.	United States
US EPA	United States Environmental Protection Agency
USDA	United States Department of Agriculture
USDW	Underground Sources of Drinking Water
USGS	United States Geological Survey
USGS EGDB	US Geological Survey Energy Resources Program Geochemistry Laboratory Database
VCAPCD	Ventura County Air Pollution Control District
VOC	volatile organic compound
WDR	water discharge requirements
WHO	World Health Organization
WOS	Web of Science
WSPA	Western States Petroleum Association
WST	well stimulation treatment

Exhibit 24.03

This exhibit was not previously submitted in November 2023

RAILROAD COMMISSION OF TEXAS

OIL AND GAS DIVISION

1124 S. IH 35 | CAPITOL STATION — P. O. DRAWER 12967 | AUSTIN, TEXAS 78711-2967

November 15, 1984

TO PERSONS RECEIVING THE DOCUMENT

"QUESTIONS AND ANSWERS CONCERNING RULE 8"

"Questions and Answers Concerning Rule 8" was first issued on June 27, 1984. The first edition contained 38 questions and answers. A second edition of questions and answers was issued September 7, 1984. Questions and answers numbered 39 through 59 were added to the second edition. None of the first 38 questions and answers were changed at that time. A third edition of questions and answers was issued on November 9, 1984. Questions and answers numbered 60 through 67 have been added. None of the first 59 questions and answers have been changed except Number 10 which was amended to allow the placement of fresh hose-down water in the sumps covered by the small sump exclusion. An index to the questions and answers has also been added.

William H. Barnes

William H. Barnes, Legal Counsel
Underground Injection Control

WHB/jcb

QUESTIONS AND ANSWERS CONCERNING RULE 8

1. If a person utilizes the services of a carrier or receiver, how often does the person have to check to see if the carrier or receiver has all required Oil and Gas Division permits? [Rule 8(d)(5)(A)]

   Once during the life of the permit in question. The person utilizing the services of the carrier or receiver should determine the life of the permit in question.

2. How will the Commission let people know if a carrier or receiver has had its permit modified, suspended, or terminated?

   This information will be mailed out monthly in a special mailout for those requesting the information. Requests for information should be sent to Railroad Commission of Texas, Oil and Gas Division - UIC, P. O. Drawer 12967, Austin, Texas 78711.

3. Does a person utilize the services of a receiver even though he only deals with the carrier and the carrier hires the receiver?

   Yes.

4. Must any particular company official sign the Form H-11?

   No. The person only needs to be able to sign the certificate. The person signing could even be a consultant rather than a regular employee.

5. Can lube oil from gas compressors go to a reclamation plant?

This movement of oil is not a disposal requiring a permit under Rule 8. However, movement of lube oil to the reclamation plant would require a letter of authority pursuant to the reclamation plant permit issued under Rule 57.

6. Can lube oil from gas compressors go to stock tanks?

   This movement of oil is not a disposal requiring a permit under Rule 8, but the mixing of lube oil and crude oil would be subject to regulation under other Commission rules.

7. Will the Railroad Commission regulate domestic trash and sewage generated at camps and gas plants?

   No. These wastes are regulated by local health departments.

8. When applying for a permit for a gas plant evaporation/retention pit, can the plat just locate the pit in relation to survey lines if lease lines do not exist?

   Yes.

9. Is a bell hole, which is constructed to allow repair of pipeline leaks, a pit within the meaning of Rule 8?

   No.

10. Is a sump which is used to collect various types of oily wastes a pit within the meaning of Rule 8?

   A sump, which

   (1) has a capacity of 500 gallons or less,

   (2) is constructed of concrete, steel, or fiberglass, and

(3) is used to collect

(a) lube oil or antifreeze from machinery,

(b) glycol from a dehydration system,

(c) pigging liquids at a pig trap, or

(d) fresh hose-down water

is not a pit requiring a permit under Rule 8, regardless of whether the sump is an enclosed vessel or open to the atmosphere, provided the material collected in the sump is removed from the sump in a reasonable period of time.

11. Is a totally-enclosed, buried tank a pit within the meaning of Rule 8?

    Yes, if the tank contains oil and gas wastes (as opposed to products), unless the tank falls into the small sump exclusion outlined in the answer to Question 10.

12. If a person ships oil and gas waste to a TDWR or TDH landfill, may that person file a copy of a shipping control ticket after shipping the waste rather than obtaining a minor permit before shipping the waste?

    No.

13. If an operator plans to replace an existing pit with a new pit, but the new pit cannot be constructed within 180 days of the effective date of the Rule 8 amendments, what procedure should the operator follow?

    Apply for a permit on both pits. The Commission should be informed that the one pit is to replace the other. The Commission will consider permitting the existing pit on a compliance schedule that recognizes the schedule for bringing the new pit on line.

Exhibit 26.01

This exhibit was not previously submitted in November 2023

MILESTONE
ENVIRONMENTAL
SERVICES

September 25, 2024

Railroad Commission of Texas
Rules Coordinator: rulescoordinator@rrc.texas.gov

Milestone Environmental Services is an environmental infrastructure services company formed in 2014. Milestone owns and operates 14 commercial disposal facilities in Texas and New Mexico and specializes in handling and safely disposing of drilling, completion and production waste.

Milestone supports updating Rule 8 and has advocated for tighter regulations related to commercial facilities like Milestone's. The proposed Rule 8 changes to commercial waste disposal practices are welcomed and Milestone takes no exception to them.

However, the absence of meaningful updates to non-commercial waste practices – i.e. the use of reserve pits – is alarming. The realities of modern drilling practices necessitate modern waste disposal rules, and the August draft of Rule 8 (now Chapter 4, Subchapter A) falls woefully short in that respect.

It is undeniable that drilling and production practices are vastly different now than in 1984, which is the last time Rule 8 was updated. Horizontal, shale drilling generates exponentially more waste than shallow, conventional drilling. Horizontal wellbore lengths are much longer and require different, more complex fluids. The fluids used in horizontal drilling contain oil-based muds and chemical fracking fluids. On average, a vertical well generates between 2,000 and 5,000 barrels of waste. By comparison, on average, just one horizontal well generates between 8,000 and 16,000 barrels of waste, with multiple wells using one large reserve pit. This data is not controverted and can be validated by the quarterly reports submitted to the Railroad Commission by commercial disposal facility operators.

And yet, in Texas, drilling waste can be permanently buried onsite with virtually no oversight and no restrictions. Further, the landowner often has no knowledge of the reserve pit's contents and is unaware that burial will take place. Texas is the only state in the country that allows onsite burial without the landowner's consent.

The Railroad Commission can update Rule 8 to address current drilling practices and current waste contents and volumes without imposing undue cost or operational burdens on smaller operators. Stated another way: we do not have to choose between cost and environmental protection.

Modernized Waste Management Practices Do Not Increase Operator Cost

Updated pit regulations are not prohibitively costly and will not put small operators out of business. Quite the opposite is true. In fact, it is often less expensive or roughly the same cost to use offsite disposal or closed loop systems versus on-site burial. Even when onsite burial is less expensive at the time of pit closure, the cost to remediate a reserve pit when it later contaminates the soil and groundwater is exponentially higher than using proper practices in the first place.

Based on Milestone's experience, reserve pits that were not properly constructed and closed often fail. Free liquids that should have been removed, but were not, cause sink holes across the pit surface. The liner is torn in multiple places. Drilling fluids and cuttings have migrated to the surface. Remediation requires excavating an area typically 2 or 3 times the size of the original reserve pit to remove all contamination. The additional liability and cost to the operator, as well as groundwater and soil contamination, could have easily been avoided.

A review of the case study published by the Railroad Commission in support of its Waste Minimization Program confirms this fact.

In the Railroad Commission's case study, attached here as Exhibit A, a small, independent operator drilling shallow, vertical wells, **saved approximately $10,000 per well by using a closed loop drilling system, which eliminated the need for a reserve pit**.[1]

The Railroad Commission's conclusion is consistent with Milestone's findings. For most smaller drilling operations, closed-loop drilling is cost-neutral or a moderate savings to the operator.

For larger drilling operations, the utilization of proper waste management practices (including closed loop drilling systems) constitutes less than 2% of the total spend for a well. In other words, the cost to protect groundwater and the environment is negligible and not determinative for larger operators.

Reserve Pit Failures Cause Groundwater Contamination

Increased reserve pit standards are necessary because of the direct correlation between failed reserve pits and groundwater contamination. **This has been confirmed since the late 1980s.**

[1] Exhibit A. See also https://www.rrc.texas.gov/oil-and-gas/publications-and-notices/publications/waste-minimization-program/waste-minimization-case-histories/closed-loop-drilling-fluid-system/

In its 1987 Report to Congress, which originated in Texas but was subsequently expanded to include other states, the Environmental Protection Agency confirmed that unlined reserve pits are responsible for multiple incidents of groundwater contamination.[2]

Currently, both the TCEQ Joint Groundwater Contamination Report (issued annually) and Railroad Commission field inspection reports have recorded thousands of surface and groundwater pollution events. There are many documented cases directly linking contamination to reserve pits, and even more instances where pits have contributed to groundwater contamination without being identified as the primary source.

The Railroad Commission has documented nearly 70,000 instances of unpermitted oil and gas waste disposal, 3,200 unpermitted uses of pits**, and 715 recorded cases of surface or groundwater contamination** just since 2015. Additional reserve pit-related pollution cases are documented in the 2023 Texas Joint Groundwater Contamination Report, attached as Exhibit B, which identifies 560 groundwater contamination cases under the Railroad Commission's jurisdiction.[3]

Finally, we urge you to speak with any landowner in West, East or South Texas who lives with ongoing oil and gas operations on their land and ask them about contamination issues they face every day. A cursory litigation search reveals dozens of active lawsuits in Texas filed by surface owners against operators for pollution of surface and groundwater related to drilling fluids.

One ranching family has identified over 500 contamination events on their property, many due to failed reserve pits, and is grappling with widespread confirmed contamination of the groundwater and soil. The water cannot be consumed by humans or livestock, and vegetation has not been able to regrow in impacted areas.

Industry Largely Supports Updated Waste Rules

Texas lags virtually every other state and most countries in its drilling waste management regulations. Many operators have already adopted modern waste practices in Texas, both to align with their corporate values and to standardize disposal practices across all states in which they operate. It is well past time for Texas to modernize its requirements.

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[2] https://archive.epa.gov/epawaste/nonhaz/industrial/special/web/pdf/530sw88003a.pdf

[3] Exhibit B. https://www.tceq.texas.gov/groundwater/groundwater-planning-assessment/sfr-056-joint-groundwater-monitoring-contamination-report

Proposed Change

Milestone’s proposed change to the August draft of Rule 8 is as follows:

Reserve pits and mud circulation pits should be moved from “Schedule A Authorized Pits” to “Schedule B Authorized Pits”. Schedule B Authorized Pits are subject to reasonable construction, operation and closure standards protective of groundwater and soil.

Exhibit A

Closed Loop Drilling Fluid System

Problem: A small independent operator was concerned about the volume of drilling waste in conventional reserve pits at his drilling locations. Waste management costs were a concern, as well as the costs associated with impact on adjacent land due to pit failures. The operator was concerned about the potential for surface water or ground water contamination and the associated potential liabilities.

Solution: The operator was drilling relatively shallow wells in normally pressured strata. Because the drilling plan was relatively simple, the operator investigated the feasibility of using a closed-loop drilling fluid system for these wells. The use of a closed-loop system eliminated the need for a conventional reserve pit. The operator negotiated with drilling contractors to obtain a turn-key contract that required the drilling company to use a closed-loop system and take responsibility for recycling the waste drilling fluid.

Benefits: The turn-key contract was incrementally more expensive. However, because of reduced drillsite construction and closure costs, reduced waste management costs, and reduced surface damage payments, the operator realized a savings of about $10,000 per well. Also, the operator reduced the potential for environmental impact and associated potential liability concerns.

Exhibit B

May 2023 Joint Groundwater Contamination Report

https://www.tceq.texas.gov/groundwater/groundwater-planning-assessment/sfr-056-joint-groundwater-monitoring-contamination-report

Texas Groundwater Protection Committee

Committee Membership: Texas Commission on Environmental Quality
Texas Water Development Board
Railroad Commission of Texas
Texas Department of State Health Services
Texas Department of Agriculture
Texas State Soil and Water Conservation Board
Texas Alliance of Groundwater Districts
Texas A&M AgriLife Research Bureau of Economic Geology
The University of Texas at Austin Texas Department of Licensing and Regulation

Oil-field cleanup activities fall under the jurisdiction of the RRC and are subject to regulations under Statewide Rule (SWR) 8, SWR 20, SWR 91, and RRC Special Orders. Other rules that protect groundwater and influence cleanup activities include: SWR 13 (well completion requirements), SWR 14 (plugging requirements), SWR 9 (injection [disposal] into a non-productive zone), SWR 46 (injection into a productive zone), SWR 57 (reclamation plants), SWR 93 (water quality certification), SWR 98 (standards for management of hazardous oil and gas waste), and 16 TAC 4.601 - 4.632 (disposal of oil and gas NORM waste). Through SWR 30 (Memorandum of Understanding), RRC maintains jurisdiction over natural gas plants and compressor stations. If groundwater contamination occurs at a site, the responsible party is required to remediate to acceptable levels. Responsible parties may volunteer remedial action, or cleanup may be required by legal action (Operator Cleanup Program). Operators, developers, or individuals who are not responsible for the contamination may participate in the Voluntary Cleanup Program. When investigation and research cannot locate a responsible party, the Site Remediation Section of the Oil and Gas Division will oversee the remediation of the groundwater contamination with Oil and Gas Regulatory and Cleanup (OGRC) funds (State Funded Cleanup Program).

Status of Groundwater Contamination. This report includes 560 groundwater contamination cases located in 118 counties. Of these, 5 are new cases added under RRC regulations. Cases were due to self-reporting, routine investigation, review of data, complaints, violation letters, and legal enforcement action. Two sites were transferred from OCP to CU, activities were completed on six cases listed in the report, and 6 cases were removed from the previous report.

Current RRC Online Inspection Report

https://webapps2.rrc.state.tx.us/PDA/ice/pdaIceHome.xhtml?action=reloadQueryAction

As of 9/12/24

Violations

Violation query: 8(b) Surface and groundwater contamination
8(d)(1) Unpermitted disposal of waste
8(d)(2) Unpermitted use of pit

Prior to being added to the Joint Groundwater Contamination Report, cases are often identified by agency-specific routine investigations and or as a response to complaints. The following is drafted from the living RRC online inspection lookup. They represent inspection, violations, and enforcement. Data prior to August 1, 2015, is not available via this record archive. The current report includes 69,746 instances of unpermitted disposal of oil and gas waste, 3,252 unpermitted uses of pits, and 715 surface or groundwater pollution violations across all RRC oil and gas districts.
Major Violation Indicator cases: **19**
Referred to Austin for possible legal enforcement: **29**
Cases associated with RRC reserve, workover, completion and other onsite pits: **116**

Joint Groundwater Contamination Report site list

COUNTY	DIVISIO	DISTRIC	NEW	FILE NAME	FILE NUMBER	LOCATION	CONTAMINATION DESCRIPTION
GALVESTON	RRC	03		REEF EXPLORATION	OCP#2214	RESERVE PITS AT FORMER TEPPCO WELL (TEXAS NO 3)	BENZENE, BARIUM, CHLORIDE
GALVESTON	O&G	03		E.A. DEWITT FEE FORMER PIT (LEASE NO 05611)	OCP#5164	BP AMERICA PRODUCTION COMPANY	TPH, BTEX, CHLORIDES
GALVESTON	O&G	03		LEAGUE CITY HISTORIC PITS	OCP#4970	CONOCO PHILLIPS	TPH, BTEX, OTHER METALS, CHLORIDE
ANDREWS	O&G	08		SAN ANDRES PITS	OCP#5038	ENTERPRISE PRODUCTS OPERATING LLC	CHLORIDE
BRAZORIA	O&G	03		WEST COLUMBIA PIT	OCP#4837	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMP	TPH, BTEX, PSH, CHLORIDE
CALDWELL	O&G	01		R.W. CARTER PIT, SALT FLAT FIELD	OFCU#60292	CRYSTAL OIL & LAND CO.	TPH
CHAMBERS	O&G	03	*	WEST STORAGE BRINE PIT 1	OCP#4935	ENTERPRISE PRODUCTS TEXAS OP LP	CHLORIDE
FORT BEND	O&G	03		FORMER WELL NO. 6 SITE	OCP#5081	ATLAS OIL & GAS EXPLORATION, LLC	TPH, BTEX, SVOCS
GALVESTON	O&G	03		LEAGUE CITY HISTORIC PITS	OCP#4970	CONOCO PHILLIPS	TPH, BTEX, OTHER METALS, CHLORIDE
HARRIS	O&G	03		FORMER SUN HUMBLE PITS SITE (HUMBLE, TX) (RRC ORDER :	OCP#1064	SUNOCO INC.	TPH, PSH
HARRIS	O&G	03	*	RESERVE PIT G	OCP#5285	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMP	CHLORIDE
HIDALGO	O&G	04		EAST MCCOOK PIT	OCP#5026	SHELL EXPLORATION AND PRODUCTION CO.	TPH, BTEX
HOCKLEY	O&G	8A		ELLWOOD "A" LEASE (06169), WELL NO. 50W	OCP#5189	APACHE CORPORATION	BTEX, CHLORIDE, TDS, LI, RA, SR, V
HOCKLEY	O&G	8A		RATLIFF SITE, NON-SABINAL OWNED PROPERTY	OCP#5202	SABINAL ENERGY OPERATING, LLC, FORMERLY CHEVRON USA INC.	CHLORIDE
HOUSTON	O&G	06		PIT, NAVARRO CROSSING FEE PROPERTY NOS. 95892/107580	OCP#4458	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMP	CHLORIDE
HOWARD	O&G	08		O'DANIEL PIT TRENCH	OCP#3095	MERIT ENERGY CO.	CHLORIDE
JEFFERSON	O&G	03		BIG HILL PITS	OCP#1037	CHEVRON (FORMERLY UNOCAL)	CHLORIDE
JIM WELLS	O&G	04		PODEST PIT	OFCU#106643/	CORPUS CHRISTI - JEROME PODEST	TPH
KARNES	O&G	02		MAURER MCFARLAND UNIT LEASE RELEASE	OCP#5141	MARATHON OIL EF LLC	TPH, BTEX
KLEBERG	O&G	04		KING RANCH MADERO 8 PIT RELEASE	OCP#4923	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMP	TPH, BTEX, OTHER METALS, CHLORIDE
LIBERTY	O&G	03		CLUBB, A.J. #1 (GREGG ROYALTY)	OFCU#60934	200 ARKANSAS, DAISETTA, TX 77533	CHLORIDE
MONTAGUE	O&G	09		MONTAGUE SALT-WATER DISPOSAL PITS	OCP#2430	MULTIPLE OPERATORS	CHLORIDE
NOLAN	O&G	7B		LAKE TRAMMEL UNIT PIT	OCP#5107	MERIT ENERGY COMPANY	TPH, BTEX, CHLORIDE
NUECES	O&G	04		DRISCOLL #3 SITE	OCP#4178	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMP	TPH, BTEX, PAH, VOCS, CHLORIDE
PANOLA	O&G	06		ALLISON LEASE	OCP#4844	BP AMERICA PRODUCTION COMPANY	BENZENE, NATURAL GAS, CHLORIDE
PANOLA	O&G	06		BEASLEY 3 LEASE, WELL #5	OCP#5187	CONOCOPHILLIPS COMPANY	BTEX, CHLORIDE, TDS
SAN PATRICIO	O&G	04		HOSKINSON WELL NO. A4	OCP#1974	CHEVRON ENVIRON. MANAGEMENT CO. (FORMERLY PURE RESOUF	BENZENE, PSH
SCURRY	O&G	8A		SACROC UNIT PITS	OCP#5093	KINDER MORGAN PRODUCTION COMPANY, LLC	TPH, CHLORIDE
STARR	O&G	04		SAMANO, M. (07975) LEASE PIT	OCP#5147	TRINITY RIVER ENERGY OPERATING, LLC	TPH, BENZENE
VAN ZANDT	O&G	05		ENAS PIT SITE	OCP#1872	CHEVRON (FORMERLY UNOCAL, PURE RESOURCES)	TPH, BENZENE, CHLORIDE
NUECES		REM/SF		BALLARD PITS	SUP099	LOTS 2 & 3 OF SECTION 6 OF THE WADE RIVERSIDE SUBDIVISION, C	TOTAL PETROLEUM HYDROCARBONS
GALVESTON	RRC	03		DMA DEVELOPMENT LLC	VCP#3-90004	NW CORNER OF FM 646 AND 11TH ST, SANTA FE	CHLORIDE
BEE	RRC	2		EXXON MOBIL CORPORATION	OCP#1285		BTEX IN GROUNDWATER
BROOKS	RRC	4		HILCORP ENERGY CORPORATION	OCP#2043	GLORIA GARCIA LOPEZ #1	BENZENE
COKE	RRC	7C		ORYX ENERGY CORPORATION		JAMESON FIELD	CHLORIDES
ECTOR	RRC	8		TEXACO EXPL & PROD	OCP#1802	MCKNIGHT	PSH ON GROUNDWATER
HARRIS	RRC	3		ISAACKS RD PROPERTIES, WESTERN VACANT LOT	OCP#4820	CHEVRON ENVIRONMENTAL MANAGEMENT COMPANY	CHLORIDE
HIDALGO	RRC	4		FORMER SHELL GAS WELL (1401 N. 16TH ST. MCALLEN)	OCP#5159	SHELL EXPLORATION AND PRODUCTION COMPANY	CHLORIDE, TDS, AS
HIDALGO	RRC	4		FORMER SHELL GAS WELL (1401 N. 16TH ST. MCALLEN)	OCP#5159	SHELL EXPLORATION AND PRODUCTION COMPANY	CHLORIDE, TDS, AS
MONTGOMERY	RRC	03		BISHOP TRACT, BRINE PIT RELEASE	OCP#4294/VCP	GEOSOUTHERN ENERGY CORP.	TPH, BTEX, CHLORIDES, PSH
CALLAHAN	O&G	7B		BAKER RANCH SEEP	OFCU#60296	UNIDENTIFIED	TPH, BTEX, PSH
GREGG	O&G	6E		ANDERSON COLLECTION CENTER PIT	OCP#5125	EAST TEXAS SALTWATER DISPOSAL	BTEX, CHLORIDE

RRC violations list

Violation Discovery Date	Violated Rule Description	Violated Rule	Oil & Gas District	Operator Name	Lease No	Lease/Facility Name	County	Well No	Last Enforcement Action	Last Enforcement Action Date
12/28/2018	Surface or subsurface water pollution	16 TAC §	7B	FINLEY RESOURCES, INC.	01862	TUCKER, S. P.	FISHER	7	Notice of Violation	01/03/2019
12/26/2022	Surface or subsurface water pollution	16 TAC §	09	RIDGE OIL COMPANY	29703	IMU	YOUNG	2623I	Issued a Severance/Se	12/28/2022
12/21/2015	Surface or subsurface water pollution	16 TAC §	05	XOG OPERATING LLC	02449	EDENS 'A'	NAVARRO	1	Notice of Violation	12/29/2015
12/18/2019	Surface or subsurface water pollution	16 TAC §	7B	M & K OPERATING LLC	05881	DAVIS, MERRICK -A-	SHACKELFORD	2	Notice of Violation	12/31/2019
12/17/2019	Surface or subsurface water pollution	16 TAC §	09	RICHEY, RAY MANAGEMENT CO., INC.	150430	RATLIFF, L. D.	WISE	3	Notice of Violation	10/23/2020
12/14/2017	Surface or subsurface water pollution	16 TAC §	7B	BASA RESOURCES, INC.	14358	EAST ELIASVILLE (CADDO) UNIT	STEPHENS	187	Notice of Violation	12/15/2017
12/12/2018	Surface or subsurface water pollution	16 TAC §	7C	ATM ENERGY GROUP, LLC	02654	VAUGHAN, ISABEL -D-	CROCKETT	12W	Notice of Violation	01/28/2019
12/09/2016	Surface or subsurface water pollution	16 TAC §	03	GOLDSMITH OPERATING, LLC	19879	PIERCE	LEON	1	Notice of Violation	01/03/2017
12/07/2017	Surface or subsurface water pollution	16 TAC §	7B	BRAKA OPERATING, L.L.C.	208531	MCINTIRE	STEPHENS	1	Issued a Severance/Se	12/11/2017
12/06/2016	Surface or subsurface water pollution	16 TAC §	05	NEW CENTURY OPERATING, LLC		MARBURGER A UNIT	LEE	1H	Notice of Violation	12/09/2016
11/30/2015	Surface or subsurface water pollution	16 TAC §	06	LAYLINE ENERGY I LLC	204256	ARCO NO. 2	SHELBY	7	Notice of Violation	01/27/2016
11/19/2018	Surface or subsurface water pollution	16 TAC §	03	SANTA ROSA OPERATING, LLC		TRES BRUJITAS	WALKER	01	Notice of Violation	01/29/2019
11/17/2016	Surface or subsurface water pollution	16 TAC §	08	PEARL RESOURCES OPERATING CO.LL		GARNET STATE	PECOS	4	Notice of Violation	02/09/2017
11/15/2021	Surface or subsurface water pollution	16 TAC §	03	DARTEX ENERGY CORPORATION	01718	QUINN, B. E., ETAL #3	NEWTON	13	Notice of Violation	11/17/2021
11/14/2018	Surface or subsurface water pollution	16 TAC §	03	COVEY PARK OPERATING LLC	25729	GRESHAM TRUST	LEON	1H	Notice of Violation	01/22/2019
11/12/2019	Surface or subsurface water pollution	16 TAC §	06	KJ ENERGY, LLC		KENNEDY GAS UNIT	RUSK	7H	Notice of Violation	12/17/2020
11/12/2015	Surface or subsurface water pollution	16 TAC §	06	SAMSON LONE STAR, LLC	136967	HOLT, J. W.	GREGG	2	Violation Corrected	02/23/2016
11/09/2015	Surface or subsurface water pollution	16 TAC §	05	CH4 ENERGY II, LLC	03636	POWER-TRUST / T BAR-X	ROBERTSON	1	Notice of Violation	11/12/2015
11/04/2015	Surface or subsurface water pollution	16 TAC §	7C	PARSLEY ENERGY OPERATIONS, LLC	17402	ARNETT 44	REAGAN	4	Notice of Violation	11/05/2015
11/02/2018	Surface or subsurface water pollution	16 TAC §	08	ROVER PETROLEUM OPERATING, LLC	21120	WESTBROOK SOUTHWEST UNIT	MITCHELL	410	Notice of Violation	12/04/2018
10/28/2016	Surface or subsurface water pollution	16 TAC §	05	MUELLER EXPLORATION, INC.	04066	GRANT	HENDERSON	1	Notice of Violation	01/03/2017
10/20/2015	Surface or subsurface water pollution	16 TAC §	10	CHESAPEAKE OPERATING, L.L.C.	265577	NELL, PATSY	HEMPHILL	2H	Notice of Violation	10/27/2015
10/19/2016	Surface or subsurface water pollution	16 TAC §	01	BLACKMAR, JIM OIL OPERATOR		METZLER, JACK	CALDWELL	1	Notice of Violation	02/09/2017
10/16/2015	Surface or subsurface water pollution	16 TAC §	7C	ENDEAVOR ENERGY RESOURCES L.P.	03361	ZULETTE	REAGAN	2	Notice of Violation	10/21/2015
10/15/2015	Surface or subsurface water pollution	16 TAC §	7C	ENDEAVOR ENERGY RESOURCES L.P.	10052	MERTZ (P) 2-12	REAGAN	3	Notice of Violation	11/17/2015
10/15/2015	Surface or subsurface water pollution	16 TAC §	7C	ENDEAVOR ENERGY RESOURCES L.P.	05562	WEGER UNIT	CROCKETT	802	Notice of Violation	10/16/2015
10/13/2016	Surface or subsurface water pollution	16 TAC §	10	LE NORMAN OPERATING LLC	280331	LEWIS 32	HEMPHILL	1H	Notice of Violation	10/17/2016
10/13/2016	Surface or subsurface water pollution	16 TAC §	10	4P ENERGY TEXAS, LLC	09424	HUMPHREYS 59 UNIT	HEMPHILL	5HB	Notice of Violation	11/29/2016
10/07/2021	Surface or subsurface water pollution	16 TAC §	04	ARETE OPERATING COMPANY, LLC		HAYNES ESTATE	ZAPATA	10	Notice of Violation	11/30/2021
10/07/2019	Surface or subsurface water pollution	16 TAC §	08	SILTSTONE RESOURCES OP II, LLC		STATE-HAYTER 35/42S	PECOS	4HA	Notice of Violation	12/04/2019
10/02/2015	Surface or subsurface water pollution	16 TAC §	01	ENERGON3		ANGEL ARMS	WILSON	1	Notice of Violation	10/05/2015
09/28/2015	Surface or subsurface water pollution	16 TAC §	09	LMH ENERGY	14449	KEMPNER -H-	WICHITA	4	Notice of Violation	09/29/2015
09/26/2018	Surface or subsurface water pollution	16 TAC §	09	RYAN, JOSEPH G.	07418	ADAMS, GEO. G.	YOUNG	1	Notice of Violation	09/27/2018
09/24/2015	Surface or subsurface water pollution	16 TAC §	10	UNIT PETROLEUM COMPANY	269374	ISAACS 'D' SL	HEMPHILL	3H	Notice of Violation	01/07/2016
09/23/2015	Surface or subsurface water pollution	16 TAC §	10	APACHE CORPORATION		NIX 83 UNIT	HEMPHILL	2H	Notice of Violation	09/29/2015
09/21/2016	Surface or subsurface water pollution	16 TAC §	09	STAMPER OPERATING CO., INC.		WILLIAMS	JACK	2	Notice of Violation	03/05/2019
09/19/2016	Surface or subsurface water pollution	16 TAC §	01	ADVANTAGEWON OIL, US, CORP.		HW WISEMAN	WILSON	30	Notice of Violation	09/22/2016
09/17/2015	Surface or subsurface water pollution	16 TAC §	09	FIVE STATES OPERATING CO, LLC		WAGGONER-EPCO	WILBARGER	5507	Notice of Violation	09/18/2015
09/14/2015	Surface or subsurface water pollution	16 TAC §	7B	WINCO OIL INC.		HINDS	TAYLOR	1	Notice of Violation	09/17/2015
09/10/2015	Surface or subsurface water pollution	16 TAC §	10	LE NORMAN OPERATING LLC		GEORGE 36	HEMPHILL	1H	Notice of Violation	09/11/2015
09/08/2015	Surface or subsurface water pollution	16 TAC §	10	BP AMERICA PRODUCTION COMPANY	274741	WRIGHT A	HEMPHILL	2H	Notice of Violation	09/09/2015
09/08/2015	Surface or subsurface water pollution	16 TAC §	09	TRI ENERGY RESOURCES, INC.	19924	WARD, MAMIE MCFADDIN -A-	KNOX	2W	Referred to Austin Field	09/09/2015
09/06/2023	Surface or subsurface water pollution	16 TAC §	09	TRI ENERGY RESOURCES, INC.		FARMER, ANNA BETH	KNOX	9	Referred to State-Mana	09/07/2023
08/17/2015	Surface or subsurface water pollution	16 TAC §	08	BEACH OIL & GAS, INC.	30825	LINEBERY -E-	WINKLER	1	Notice of Violation	10/01/2015
08/17/2015	Surface or subsurface water pollution	16 TAC §	8A	CROSS TIMBERS ENERGY, LLC	60378	HARRISON, LEE UNIT	LUBBOCK	1202	Notice of Violation	08/27/2015
08/17/2015	Surface or subsurface water pollution	16 TAC §	08	BEACH OIL & GAS, INC.	30825	LINEBERY -E-	WINKLER	1B	Notice of Violation	10/01/2015
08/17/2015	Surface or subsurface water pollution	16 TAC §	08	BEACH OIL & GAS, INC.	30825	LINEBERY -E-	WINKLER	2	Notice of Violation	10/01/2015
08/17/2015	Surface or subsurface water pollution	16 TAC §	08	LINN OPERATING, INC.		NOBLES	MIDLAND	2H	Notice of Violation	08/29/2015
08/17/2015	Surface or subsurface water pollution	16 TAC §	08	BEACH OIL & GAS, INC.	30825	LINEBERY -E-	WINKLER	3	Notice of Violation	10/01/2015
08/12/2019	Surface or subsurface water pollution	16 TAC §	7B	RONNING GAS AND OIL LLC	12913	KINCAID, ALVIN	EASTLAND	1	Notice of Violation	08/13/2019
08/12/2015	Surface or subsurface water pollution	16 TAC §	02	GRAND RESOURCES, INC.	06705	KUPPINGER SWD	JACKSON	1	Notice of Violation	08/19/2015
08/12/2015	Surface or subsurface water pollution	16 TAC §	08	ENERGEN RESOURCES CORPORATION	39543	UNIVERSITY 11-19	LOVING	1H	Notice of Violation	08/25/2015
08/10/2018	Surface or subsurface water pollution	16 TAC §	08	NBL PERMIAN LLC		BLACK COBRA 1-2 UNIT B	REEVES	66H	Notice of Violation	08/15/2018

08/08/2018	Surface or subsurface water pollution	16 TAC §	08	FLAMINGO OPERATING, LLC		REED B 15	PECOS	10	Notice of Violation	12/04/2018
08/08/2018	Surface or subsurface water pollution	16 TAC §	08	FLAMINGO OPERATING, LLC		REED 'A' 23	PECOS	3	Referred to State-Mana	01/31/2020
08/07/2015	Surface or subsurface water pollution	16 TAC §	8A	MCDONALD PRODUCTION, LLC	63444	DEAN, C. L.	LUBBOCK	1	Notice of Violation	08/18/2015
08/07/2015	Surface or subsurface water pollution	16 TAC §	7B	ITX CORPORATION	28346	VEALE-PARKS (CADDO) UNIT	STEPHENS	3	Issued a Severance/Se	08/11/2015
08/02/2021	Surface or subsurface water pollution	16 TAC §	09	RIDGE OIL COMPANY	29703	IMU	YOUNG	2624I	Notice of Violation	09/14/2021
08/02/2019	Surface or subsurface water pollution	16 TAC §	09	GUIDANCE OIL DEVELOPERS	10057	HUDSON-FISH UNIT	ARCHER	6	Notice of Violation	08/27/2019
07/28/2016	Surface or subsurface water pollution	16 TAC §	03	PARTEN OPERATING INC.	22761	FORT TRINIDAD DEXTER UNIT	HOUSTON	315	Notice of Violation	08/01/2016
07/12/2019	Surface or subsurface water pollution	16 TAC §	01	VERDISYS LLC		GOODSON	VAL VERDE	3	Notice of Violation	05/05/2020
07/10/2018	Surface or subsurface water pollution	16 TAC §	6E	WILLIAMS LEASE CAPITAL GROUP,LLC	07753	WILLIAMS	GREGG	5	Notice of Violation	12/12/2018
07/09/2021	Surface or subsurface water pollution	16 TAC §	09	MASSIE OIL COMPANY	01583	SHUMAKE	CLAY	45	Notice of Violation	07/12/2021
07/08/2016	Surface or subsurface water pollution	16 TAC §	09	M3 OIL COMPANY, LLC		PERKINS, MELINDA	JACK	2	Notice of Violation	02/17/2022
07/07/2016	Surface or subsurface water pollution	16 TAC §	09	FIVE STATES OPERATING CO, LLC		WAGGONER-EPCO	WILBARGER	1107	Notice of Violation	07/11/2016
06/30/2022	Surface or subsurface water pollution	16 TAC §	7C	BJG OPERATING COMPANY	14495	MCCAMEY UNIT	UPTON	S207RW	Notice of Violation	07/08/2022
06/27/2019	Surface or subsurface water pollution	16 TAC §	7C	CREST OPERATING COMPANY	15590	CAMAR, SW (STRAWN) UNIT	SCHLEICHER	12	Notice of Violation	12/06/2019
06/26/2019	Surface or subsurface water pollution	16 TAC §	09	DRAKE PETROLEUM, LLC	11141	KENDALL 2400 STRAWN SAND UN	YOUNG	1	Notice of Violation	07/02/2019
06/15/2016	Surface or subsurface water pollution	16 TAC §	05	OBAX OIL AND GAS LLC	03951	OSA	ROBERTSON	1H	Notice of Violation	06/17/2016
06/13/2019	Surface or subsurface water pollution	16 TAC §	6E	CHESTNUT EXPLOR. AND PROD., INC.	07248	ANDERSON, GEO.	GREGG	3	Notice of Violation	09/04/2019
06/13/2016	Surface or subsurface water pollution	16 TAC §	05	OBAX OIL AND GAS LLC	04129	MARIE	ROBERTSON	1H	Notice of Violation	06/15/2016
06/13/2016	Surface or subsurface water pollution	16 TAC §	05	OBAX OIL AND GAS LLC	04003	CHARIDEE	ROBERTSON	1H	Notice of Violation	06/15/2016
06/12/2018	Surface or subsurface water pollution	16 TAC §	03	BROOKS PETROLEUM COMPANY	26599	WILLIAM B. HARRISON	HOUSTON	1H	Notice of Violation	06/14/2018
06/07/2016	Surface or subsurface water pollution	16 TAC §	05	OBAX OIL AND GAS LLC	03569	OWEN	ROBERTSON	1H	Notice of Violation	08/30/2016
06/07/2016	Surface or subsurface water pollution	16 TAC §	08	ELEVATION RESOURCES LLC		WHISKEY BARREL STATE 12	REEVES	1H	Notice of Violation	06/10/2016
05/29/2022	Surface or subsurface water pollution	16 TAC §	03	GALVESTON BAY OPERATING CO LLC	08004	TRINITY BAY STATE UNIT NO. 1	CHAMBERS	108 H	Referred to Austin Field	05/31/2022
05/24/2019	Surface or subsurface water pollution	16 TAC §	7C	LAREDO PETROLEUM, INC.	19148	SRH E 7-8 (PSA-A)	REAGAN	1SM	Notice of Violation	05/28/2019
05/21/2018	Surface or subsurface water pollution	16 TAC §	7B	WEST INLAND ENERGY, INC.	162620	HART RANCH 23	STEPHENS	1	Notice of Violation	05/22/2018
05/20/2019	Surface or subsurface water pollution	16 TAC §	7C	PIONEER NATURAL RES. USA, INC.	12620	NEAL "F"	UPTON	4D	Notice of Violation	05/22/2019
05/18/2017	Surface or subsurface water pollution	16 TAC §	03	GOLDSMITH OPERATING, LLC	20000	LANE	LEON	1	Notice of Violation	11/09/2017
05/17/2024	Surface or subsurface water pollution	16 TAC §	6E	BASA RESOURCES, INC.	07036	TURNER, J. W.	RUSK	33	Notice of Violation	06/18/2024
05/12/2016	Surface or subsurface water pollution	16 TAC §	10	LE NORMAN OPERATING LLC	278396	SHELL FEE 45	HEMPHILL	2H	Notice of Violation	05/13/2016
05/08/2019	Surface or subsurface water pollution	16 TAC §	09	TAM2 SQUARED OPERATING, LLC	32799	LOFTIN D	ARCHER	3D	Notice of Violation	01/03/2020
05/07/2024	Surface or subsurface water pollution	16 TAC §	03	SENORA RESOURCES, INC.	24637	ELO #3	FAYETTE	3	Notice of Violation	07/29/2024
05/05/2020	Surface or subsurface water pollution	16 TAC §	7B	CLEARLY PETROLEUM, LLC	17853	ATKINS-TEXACO	STEPHENS	8	Notice of Violation	05/06/2020
05/01/2024	Surface or subsurface water pollution	16 TAC §	04	GREEN EXPLORATION COMPANY	09602	STATE TRACT 973	NUECES	1	Notice of Violation	05/03/2024
04/30/2018	Surface or subsurface water pollution	16 TAC §	7B	WEST INLAND ENERGY, INC.	162620	HART RANCH 23	STEPHENS	1	Issued a Severance/Se	05/02/2018
04/01/2019	Surface or subsurface water pollution	16 TAC §	09	JAMES, DERYL	23896	HAUSLER BROS. LEASE	WICHITA	1	Notice of Violation	04/02/2019
03/31/2017	Surface or subsurface water pollution	16 TAC §	03	LAYLINE ENERGY I LLC	10826	ADAMS, C. T. OIL UNIT #2	HOUSTON	2	Notice of Violation	04/11/2017
03/31/2016	Surface or subsurface water pollution	16 TAC §	10	CIMAREX ENERGY CO. OF COLORADO	278337	CAMPBELL, J.C. 37	HEMPHILL	4H	Notice of Violation	04/04/2016
03/22/2019	Surface or subsurface water pollution	16 TAC §	09	FABELA OPERATING, LLC	26424	ELLEDGE-FURR	BAYLOR	1D	Notice of Violation	06/18/2019
03/16/2018	Surface or subsurface water pollution	16 TAC §	10	LATIGO PETROLEUM TEXAS, LP		COURSON RANCH 157	ROBERTS	11	Notice of Violation	04/17/2018
03/14/2024	Surface or subsurface water pollution	16 TAC §	04	LAMAR OIL & GAS, INC.	151428	NINE MILE PT. FLD. CONSL. UNIT	ARANSAS	17	Notice of Violation	03/18/2024
03/12/2020	Surface or subsurface water pollution	16 TAC §	7C	APACHE CORPORATION	18159	MC ELROY RANCH CO D	UPTON	2A	Notice of Violation	04/09/2020
03/11/2020	Surface or subsurface water pollution	16 TAC §	08	SEGURO OIL AND GAS, LLC	36685	UNIVERSITY "J"	CRANE	1	Notice of Violation	04/21/2020
02/27/2024	Surface or subsurface water pollution	16 TAC §	08	BIRCH OPERATIONS, INC.	57152	ROWDY THE COWBOY 42-30 E	HOWARD	7WA	Notice of Violation	05/21/2024
02/27/2024	Surface or subsurface water pollution	16 TAC §	01	SOUTHERN OIL & GAS LLC		RAMERT	MCMULLEN	2	Referred to State-Mana	03/04/2024
02/26/2019	Surface or subsurface water pollution	16 TAC §	06	SABINE OIL & GAS CORPORATION	268392	HARDY HEIRS-MODISETTE (SA)	RUSK	2H	Notice of Violation	12/18/2020
02/17/2020	Surface or subsurface water pollution	16 TAC §	08	MADISON AND WRIGHT LLC	38499	NORTHSHOT	REEVES	3	Notice of Violation	02/27/2020
02/17/2016	Surface or subsurface water pollution	16 TAC §	06	RHC ENERGY (USA) LLC		HASSLER	RUSK	1	Notice of Violation	04/22/2016
02/13/2023	Surface or subsurface water pollution	16 TAC §	09	JUST OIL & GAS, INC.	07477	ATCHLEY, KATHERINE HAMILTON	YOUNG	54 G	Notice of Violation	02/24/2023
02/12/2018	Surface or subsurface water pollution	16 TAC §	10	UNIT PETROLEUM COMPANY		DIXON 5554 CXL	HEMPHILL	6H	Notice of Violation	02/13/2018
02/09/2016	Surface or subsurface water pollution	16 TAC §	10	CORLENA OIL COMPANY		BRAINARD 64	LIPSCOMB	2H	Notice of Violation	02/11/2016
02/08/2016	Surface or subsurface water pollution	16 TAC §	05	USA SUPERIOR ENERGY LLC		CRAIG LEASE	NAVARRO	2	Referred to State-Mana	12/05/2017
01/26/2017	Surface or subsurface water pollution	16 TAC §	7B	FRONTIER RESOURCES, INC.	059669	SMITH KING W. A	STEPHENS	1	Issued a Severance/Se	01/27/2017
01/24/2019	Surface or subsurface water pollution	16 TAC §	08	DIAMONDBACK E&P LLC		NEAL LETHCO STATE 24-23 UNIT	PECOS	3WA	Notice of Violation	02/01/2019
01/16/2019	Surface or subsurface water pollution	16 TAC §	08	HALCON OPERATING CO., INC.		MAXWELL-NATALIE	PECOS	1H	Notice of Violation	01/29/2019

01/10/2023	Surface or subsurface water pollution	16 TAC § :	03	GAITHER PETROLEUM CORPORATION	01771	BEAUMONT PETROLEUM CO. - S	HARRIS	58	Notice of Violation	01/18/2023
01/10/2019	Surface or subsurface water pollution	16 TAC § :	7B	CLEARLY PETROLEUM, LLC	12449	SLOAN, MARTIN UNIT	STEPHENS	11W	Notice of Violation	01/11/2019
01/09/2017	Surface or subsurface water pollution	16 TAC § :	08	AMERICO ENERGY RESOURCES, LLC		COLEMAN RANCH UNIT	MITCHELL	410	Notice of Violation	01/30/2017
01/08/2020	Surface or subsurface water pollution	16 TAC § :	08	PARSLEY ENERGY OPERATIONS, LLC		PATTERSON 5-8-G	GLASSCOCK	4313H	Notice of Violation	01/13/2020
01/08/2016	Surface or subsurface water pollution	16 TAC § :	7C	LAREDO PETROLEUM, INC.		SUGG-A-	REAGAN	1716SM	Notice of Violation	01/11/2016
01/07/2016	Surface or subsurface water pollution	16 TAC § :	09	BLAKENERGY OPERATING, LLC		GARNER	JACK	2	Notice of Violation	01/12/2016
01/04/2023	Surface or subsurface water pollution	16 TAC § :	03	GAITHER PETROLEUM CORPORATION	10330	GOOSE CREEK WASTE WATER S	HARRIS	1	Notice of Violation	01/09/2023
01/04/2019	Surface or subsurface water pollution	16 TAC § :	7C	PIONEER NATURAL RES. USA, INC.	03913	NORTH PEMBROOK SPRABERRY	UPTON	8516A	Notice of Violation	01/07/2019

Exhibit 30.01

This exhibit was not previously submitted in November 2023

United States
Department of
Agriculture

Soil
Conservation
Service

Agricultural
Waste Management
Field Handbook

Chapter 6 Role of Plants in Waste Management

Chapter 6 Role of Plants in Waste Management

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Chapter 6 Role of Plants in Waste Management

651.0600 Introduction

Many agricultural operations produce waste by-products. Animal manure is an example of a waste by-product that can be used as a plant nutrient. Properly managed and utilized agricultural wastes are a natural resource that can produce economic returns. Waste management systems properly planned, designed, installed, and maintained prevent or minimize degradation of soil, water, and air resources while providing chemical elements essential for plant growth.

The objectives of a complete system approach to waste management are to design a system that

- recycles nutrients in quantities that benefit plants,
- builds levels of soil organic matter,
- limits nutrient or harmful contaminant movement to surface and ground water,
- does not contaminate food crops with pathogens or toxic concentrations of metals or organics, and
- provides a method in the soil environment to fix or transform nonessential elements and compounds into harmless forms.

This chapter will provide the reader with an appreciation for the plant's role in management of nutrients in an agricultural waste management system. The function and availability of plant nutrients as they occur in agricultural wastes are discussed, and the effects of trace elements and metals on plants are introduced. General guidance is given so the components of the waste can be converted to plant available form and the nutrients harvested in the crop can be estimated. The impact of excess nutrients, dissolved solids, and trace elements on plants is given in relationship to agricultural waste application.

651.0601 Agricultural waste as a resource for plant growth

The primary objective of applying agricultural waste to land is to recycle part of the plant nutrients contained in the waste material into harvestable plant forage, fruit, or dry matter. An important consideration is the relationship between the plant's nutrient requirement and the quantity of nutrients applied in the agricultural wastes. A plant does not use all the nutrients available to it in the root zone. The fraction of the total that is assimilated by the roots varies depending on the species of plant, growth stage, depth and distribution of its roots, moisture conditions, soil temperature, and many other factors. The uptake efficiency of plants generally is not high, often less than 50 percent. Perennial grasses tend to be more efficient in nutrient uptake than row crops. They grow during most of the year, and actively grow during the period of waste application, which maximizes the nutrient removal from the applied waste product.

Another major objective in returning wastes to the land is enhancing the receiving soil's organic matter content. As soils are cultivated, the organic matter in the soil decreases. Throughout several years of continuous cultivation in which crop residue returns are low, the organic matter content of most soils decreases dramatically until a new equilibrium is reached. This greatly decreases the soil's ability to hold the key plant nutrients of nitrogen, phosphorus, and sulfur. These nutrients may move out of the root zone, and crop growth will suffer. The amount of crop residue that is produced and returned to the soil is reduced.

651.0602 The plant–soil system

The plant-soil system has advantages in using the nutrients in waste products from agricultural systems. For centuries wastes have been spread on the soil to recycle nutrients because of the positive effect on plant growth. Soils have the ability to retain plant nutrients contained in the waste. Soil retention is an important storage mechanism, and the soil is enhanced by the organic matter supplied by waste. Plants absorb the nutrients in the waste, for the most part through the roots, and transform the soluble chemical elements, some of which are water contaminants, into plant tissue. This is the basis for addressing some of today's water quality concerns. Cropping systems and precisely calculated nutrient budgets can be tailored to meet planned waste application levels and crop nutrient needs and to reduce or eliminate losses from the plant-soil system.

(a) Nutrient transformation

Plant uptake is not the only form of nutrient transformation that takes place in the soil-plant system. The chemical compounds derived from waste material can be transformed by the following processes:

1. Absorbed by the roots and assimilated by the plant
2. Degraded by soil micro-organisms and become a part of the soil organic component, or broken down further into a gas, ion, or water
3. Fixed to soil minerals or attached to soil exchange sites
4. Solubilized and moved with runoff water.
5. Moved with eroded mineral or organic material
6. Leached downward through the soil toward the ground water
7. Escaped from plant tissue into the atmosphere

Plants can play a role in all of these processes. Processes 4, 5, 6, and 7 are nutrient escape mechanisms. Plant species and cultivars can be selected to interrupt many of these mechanisms. An example of process 4 is that cultivated crops that are conservation tilled and planted on the contour with grass sod improve removal of soluble nutrients by soil infiltration.

Other mechanisms might be active in the removal of some solid constituents. Many soil conservation actions reduce erosion, which interrupts process 5. Deep, fibrous-rooted plants or plants that can actively take up nutrients beyond the normal growing season of most agricultural crops interrupt process 6 by preventing escape of leaching soluble nutrients.

Plants can also be selected for their propensity to uptake a certain nutrient. Several crops are heavy users of nitrogen and accumulate nitrate, which is very soluble and leachable. Recent studies have shown that grass species vary significantly in their ability to remove and transform nitrogen within the soil. Alfalfa removes potassium and nitrogen in larger quantities and at a deeper rooting depth than most agricultural crops.

In other cases, plants may act as a catalyst or provide a better environment to promote the transformation processes. Plant growth moderates soil temperature, reduces evaporation from soil surface, provides an energy source of carbohydrates, and aggregates soil particles, which promotes high soil aeration. All this provides a better climate for a wide variety of soil micro-organisms, which aids process 2.

Process 3 is aided by plant growth as well, but generally this comes very slowly. The classic example is the difference in the cation-exchange capacity between a prairie soil and a forest soil derived from the same parent material. The surface layer of the prairie soil has a much higher organic matter content and cation-exchange capacity, at least double to sometimes nearly quadruple that of the forest soil (Jenny 1941). Yet, what takes centuries to build up can be quickly destroyed in less than two decades by erosion and excessive tillage (fig. 6–1). High residue crops in crop rotations help to prevent large decreases in soil organic matter content and have beneficial effects on nutrient retention (Wild 1988).

Denitrification is a classic example of nutrient transformation where microbial degradation and eventual escape of nitrogen gas occurs. It is an important process by which nitrogen in excess of crop requirement can be removed from the soil-plant system. This process requires the presence of nitrate-nitrogen, an organic carbon source, and anaerobic soil conditions. About one unit of organic carbon is required for each unit of nitrate-nitrogen to be denitrified (Firestone 1982).

Denitrification in land treatment systems is best accomplished if the nitrogen is in the nitrate form and the waste contains sufficient organic carbon to supply energy to the denitrifying micro-organism. Where the nitrogen in the waste material is in the organic or ammonium form, an aerobic condition must be present to convert the nitrogen to the nitrate form. During the aerobic process, the organic carbon will be oxidized by aerobic bacteria in the soil, leaving less carbon available for anaerobic microbial use when the system goes anaerobic.

Plant residue and roots are major sources of organic carbon for these microbial processes. The presence of living plants stimulates denitrification. This is attributed to two effects. First, low oxygen levels in the soil area immediately surrounding respiring plant roots creates the condition in which denitrifying anaerobes can exist. Second, root excretions can serve as a food source of decomposable organic carbon for the denitrifying bacteria.

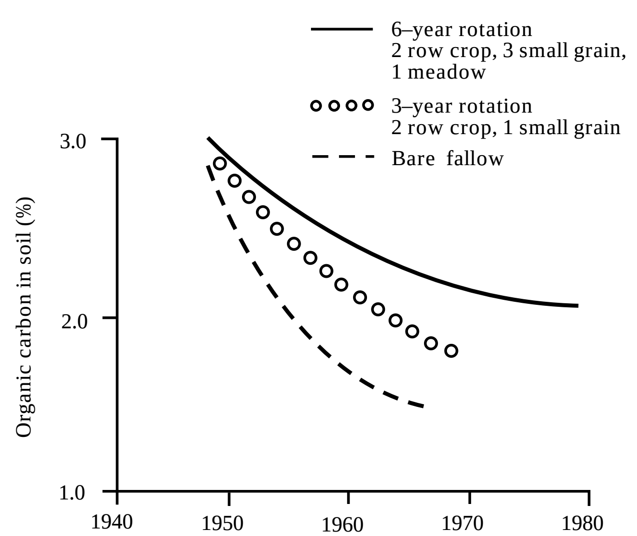
(b) Soil supports plant growth

Plant growth involves the interaction between soil and plant properties. Soil is the normal medium for terrestrial plant root growth. A plant's roots absorb nutrients and water from the soil. Roots anchored in the soil hold the plant erect. The soil must provide the environment in which roots can function.

Optimum plant growth depends on the soil having the biological, chemical, and physical conditions necessary for the plant root system to readily absorb nutrients and water. For instance, plants require soil pore space for root extension. Plant root metabolism also depends upon sufficient pore space to diffuse gases, such as oxygen and carbon dioxide. This allows for efficient root respiration, which keeps the root in a healthy condition for nutrient uptake. A decrease in soil pore space, such as that experienced with soil compaction, retards the diffusion of gases through the soil matrix, which greatly affects root growth.

Such inhibitory factors as toxic elements (aluminum or high concentrations of soluble salts) can limit or stop plant growth. Therefore, the plant's rate of absorption of nutrients involves many processes going on in the soil and plant roots.

Figure 6–1 The effects of different farming systems after three decades on the carbon content of soils from broken out sod ground



651.0603 Plant nutrient uptake

The process of element uptake by plants is complex and not totally understood. Some generally known points are:

- The process is not the same for all plants nor for all elements
- The complete process occurs within a healthy root system adequately supplied with carbohydrates and oxygen
- The essential elements must be in an available form in the root zone in balanced amounts
- Uptake varies from element to element and from crop to crop (see table 6–6)
- Soil conditions, such as temperature, moisture supply, soil reaction, soil air composition, and soil structure, affect the rate at which elements are taken up

(a) Essential plant nutrients

Plant growth can require up to 20 chemical elements. Plants get carbon, hydrogen, and oxygen from carbon dioxide and water. Nitrogen, phosphorus, potassium, sulfur, calcium, and magnesium are needed in relative large quantities. These elements are called macronutrients. Boron, chlorine, cobalt, copper, iron, manganese, molybdenum, silicon, sodium, vanadium, and zinc are needed in small amounts, or not at all, depending on the plant (Tisdale et al. 1985). These elements are called micronutrients or trace elements.

Macronutrients and micronutrients are taken from the soil-water solution. Nitrogen is partly taken from the air by nitrogen- fixing plants associated with soil bacteria. As a whole, the 20 elements listed are termed essential elements; however, cobalt, silicon, sodium, and vanadium are essential elements for the growth of only particular plant species.

(b) Nonessential elements

Besides the 20 essential elements, other elements nonessential for plant growth must be monitored where municipal sludge is used as a soil amendment. These too are referred to as trace elements. Because these elements occur as impurities, they are often inadvertently applied to soils through additions of various soil amendments. Animal waste contains certain elements that can be considered nonessential. Nickel, arsenic, and copper have been found in poultry litter. Dairy manure has elevated levels of aluminum.

(c) Nitrogen

Nitrogen is the element that most often limits plant growth. About 98 percent of the planet's nitrogen is in the Earth's primary rock. Nearly 2 percent is in the atmosphere, but it is 79 percent inert.

Even though nitrogen is abundant, it is still the nutrient most frequently limiting crop production. This is because the plant available forms of nitrogen in the soil are constantly undergoing transformation. Crops remove more nitrogen than any other nutrient from the soil. The limitation is not related to the total amount of nitrogen available, but to the form the crop can use.

Most of the nitrogen in plants is in the organic form. The nitrogen is incorporated into amino acids, the building blocks of proteins. By weight, nitrogen makes up from 1 to 4 percent of the plant's harvested material.

Essentially all of the nitrogen absorbed from the soil by plant roots is in the inorganic form of either nitrate (NO_3) or ammonium (NH_4). Generally young plants absorb ammonium more readily than nitrate; however, as the plant ages the reverse is true. Under favorable conditions for plant growth, soil micro-organisms generally convert ammonium to nitrate, so nitrates generally are more abundant when growing conditions are most favorable. Once inside the root, ammonium and nitrate are converted to other compounds or transported to other parts of the plant.

(d) Phosphorus

Phosphorus concentration in plant leaves ranges between 0.2 and 0.4 percent (Walsh & Beaton 1972). Phosphorus is important for plant growth because of its role in ribonucleic acid (RNA), the plant cells genetic material, and its function in energy transfer with adenosine triphosphate (ATP).

Phosphorus is available for absorption by plants from the soil as the orthophosphate ion (H_2PO_4 and HPO_4). These ions react quickly with other compounds in the soil to become much less available for plant uptake. The presence of aluminum, iron, calcium, and organic matter links phosphorus in highly insoluble compounds. The concentration of orthophosphate ion in the soil solution is very low, less than 0.05 mg/L, so an equilibrium is established between the soluble ion and the adsorbed form in the soil.

Phosphorus immobility in soils is caused by several factors: presence of hydrous oxides of aluminum and iron; soils that have a high clay content, especially ones high in kaolin; soils high in volcanic ash or allophane; low or high soil pH; and high exchangeable aluminum. Of these factors, the one most easily manipulated is soil pH. Maintaining a soil pH between 6.0 and 6.5 achieves the most plant available phosphorus in a majority of soils. Knowing the extent each of the factors are at work in a particular soil gives the upper limit at which phosphorus loading can occur in the soil before soluble phosphorus leaching from the soil becomes a serious water quality concern.

The relative immobility of phosphorus in the soil profile allows some agricultural waste to be applied in excess of the crop's nutrient needs, resulting in a soil phosphorus residual. Building a soil phosphorus residual can be beneficial in soils that readily fix phosphorus into an insoluble, unavailable form for plant uptake. This phosphorus reservoir, if allowed to rise, gives a corresponding rise in the soluble phosphorus content in the soil. This addition of total phosphorus has to be tempered with some restraint.

Manure applications can actually increase phosphorus leaching because organic phosphorus is more mobile through the soil profile than its inorganic counterparts. This would be particularly true on coarse textured soils that have a low cation-exchange capacity and low content of iron, aluminum, and calcium.

High phosphorus application rates appreciably increase the phosphorus concentration in the soil solution and availability for plant uptake into plant tissue, but this phosphorus rarely becomes toxic to the plant. Phosphorus toxicity depends on the plant species, phosphorus status of the plant, concentration of micronutrients, and soil salinity. Poor growth in plants that have high phosphorus levels can cause reduced nodulation in legumes, inhibition of the growth of root hairs, and a decrease in the shoot to root ratio (Kirkham 1985).

(e) Potassium, calcium, and magnesium

Potassium, calcium, and magnesium have similar reactions in the soil. The similar size and uptake characteristic can cause plant fertility problems. An excess of any one of these elements in the soil impacts the uptake of the others. It is, therefore, extremely important not to create nutrient imbalances by overapplying one of these elements to the exclusion of the others. Upon mineralization from the organic material, each element produces cations that are attracted to negatively charged particles of clay and organic matter.

Potassium is much less mobile than nitrogen, but more so than phosphorus. Leaching losses of potassium generally are insignificant except in sandy and organic soils. This is because sandy soils have a low cation-exchange capacity and generally do not have a clayey subsoil that can re-adsorb the leaching potassium. Potassium can leach from organic soils because the bonding strength of the potassium cation to organic matter is weaker than that to clay (Tisdale et al. 1985).

Some potassium is leached from all soils, even in the humid regions in soils that have strong fixing clays, but the losses do not appear to have any environmental consequences. Potassium leached from the surface soil is held in the lower horizons of the soil and returned to the surface via plant root uptake and translocation to above ground plant parts. Calcium and magnesium can occur in drainage water, but this has not been reported to cause an environmental problem. In fact, it can be beneficial in some aquatic systems. Total dissolved salts content may increase.

(f) Sulfur

Part of the sulfur applied to well drained soils ends up in sulfate form. Sulfur is oxidized by soil bacteria and fungi. The plant absorbs the oxidized sulfate ion. Sulfate concentrations between 3 and 5 mg/L in the soil are adequate for plant growth. Sulfates are moderately mobile and may be adsorbed on clay minerals, particularly the kaolinitic type, and on hydrous oxides of aluminum and to a lesser extent iron. If the soils in the waste management system are irrigated, sulfates can leach into the subsoil and even into ground water. Under poor drainage conditions, sulfates are converted mainly to hydrogen sulfide and lost to the atmosphere. In some instances, they are converted to elemental sulfur in waterlogged soils.

(g) Trace elements

Trace elements are relatively immobile once they are incorporated into the soil. The one nonmetal, boron, is moderately mobile and moves out of the rooting depth of coarse textured, acidic soils and soils that have a low organic matter content. The levels of plant available forms of all these elements are generally very low in relation to the total quantity present in soils. Some of these elements are not available for most plants to take up.

Soil reaction has the greatest influence on availability of trace elements that are taken up by plants. Except for molybdenum, the availability of trace elements for plant uptake increases as the soil pH decreases. The opposite occurs for molybdenum. For most agricultural crops, a pH range between 6.0 and 7.0 is best. As soil acidity increases, macronutrient deficiencies and micronutrient toxicity can occur depending on the nutrient, its total quantity available in the soil, and the plant in question. In alkaline soils, crops can suffer from phosphorus and micronutrient deficiencies.

Two nonessential elements of primary concern in municipal sludge are lead and cadmium. At the levels commonly found in soils or sludges, these elements have no detrimental effect on plant growth, but, they can cause serious health problems to the people or animals eating plants that are sufficiently contaminated with them. Lead can be harmful to livestock that inadvertently ingest contaminated soil or recently applied sludge while grazing. Cadmium, on the other hand, is taken up by some plants quite readily (table 6–1). If the plants are eaten, this element accumulates in the kidneys and can cause a chronic disease called proteinuria. This disease is marked by an increase of protein content in the urine.

Another nonessential element of concern is nickel. In high enough concentrations in the soil, it can become toxic to plants. Hydroxylic acid reacts with nickel to inhibit the activity of the urease molecule. This can interfere with plant metabolism of urea.

Table 6–1 Relative accumulation of cadmium into edible plant parts by different crops (USEPA 1983)*

High uptake	Moderate uptake	Low uptake	Very low uptake
Lettuce	Kale	Cabbage	Snapbean family
Spinach	Collards	Sweet corn	Pea
Chard	Beet roots	Broccoli	Melon family
Escarole	Turnip roots	Cauliflower	Tomato
Endive	Radish globes	Brussels sprouts	Pepper
Cress	Mustard	Celery	Eggplant
Turnip greens	Potato	Berry fruits	Tree fruits
Beet greens	Onion		
Carrots			

* The classification is based on the response of crops grown on acidic soils that have received a cumulative cadmium (Cd) application of 4.5 lb/ac. It should not be implied that these higher uptake crops cannot be grown on soils of higher Cd concentrations. Such crops can be safely grown if the soil is maintained at pH of 6.5 or greater at the time of planting because the tendency of the crop to assimilate heavy metals is significantly reduced as the soil pH increases above 6.5.

Two essential elements, zinc and copper, can also become toxic to plant growth if soil concentrations are excessive. These elements become toxic because they are mutually competitive as well as competitive to other micronutrients at the carrier sites for plant root uptake. Excessive concentrations of either element in the available form induces a plant nutrient deficiency for the other. High soil concentrations of copper or zinc, or both, can also induce iron and manganese deficiency symptoms (Tisdale et al. 1985).

In all, five elements of major concern have been targeted by the Environmental Protection Agency when sludge is applied to agricultural land. They are cadmium, copper, nickel, lead, and zinc. Table 6–2 shows their recommended cumulative soil limits in kilograms per hectare and in pounds per acre. Note that these loading limits depend on the soil's cation-exchange capacity and a plow layer pH maintained at 6.5 or above. Application of wastes that have these elements should cease if any one of the elements' soil limit is reached (USEPA 1983). Some states have adopted more conservative limits than those shown in table 6–2. State regulations should be consulted before designing a waste utilization plan.

Other trace elements have been identified as harmful to plant growth or potentially capable of occurring in high enough concentrations in plant tissue to harm plant consumers. They are aluminum, antimony, arsenic, boron, chromium, iron, mercury, manganese, and selenium. Generally, they do not occur in wastes, such as sludges, in high enough concentrations to pose a problem or they are only minimally taken up by crops (USEPA 1983).

As seen in table 6–1 for cadmium uptake, plants differ in their capacity to absorb elements from the soil. They also differ greatly in their tolerance to trace element phytotoxic effects. Tables giving specific tolerance levels for plant uptake are needed for individual plant species. Almost any element in the soil solution is taken into the plant to some extent, whether needed or not. An ion in the soil goes from the soil particle to the soil solution, through the solution to the plant root, enters the root, and moves from the root through the plant to the location where it is used or retained.

(h) Synthetic organic compounds

When dealing with municipal sludge, one other constraint to application rates should be addressed. Most sludge has synthetic organic compounds, such as chlorinated hydrocarbon pesticides, which can be slow to decompose and may be of concern from a human or animal health standpoint.

Polychlorinated biphenyls are in many sludges. Federal regulations require soil incorporation of any sludge that has more than 10 ppm of polychlorinated biphenyls wherever animal feed crops are grown. Polychlorinated biphenyls are not taken up by plants, but can adhere to plant surfaces and be ingested by animals and humans when the contaminated plant parts are eaten. Pesticide uptake by crops is minimal, and concentrations in wastes would be much less than that typically and intentionally applied to control pests on most cropland (USEPA 1983).

Table 6–2 Recommended cumulative soil test limits for metals of major concern applied to agricultural cropland[1] (USEPA 1983)

Metal	- - - - - - Soil cation-exchange capacity, meq/100g[2 3] - - - - - -		
	<5	5 to 15	>15
	- - - - - lb/ac (kg/ha) - - - - -		
Pb	500 (560)	1,000 (1,120)	2,000 (2,240)
Zn	250 (280)	500 (560)	1,000 (1,120)
Cu	125 (140)	250 (280)	500 (560)
Ni	125 (140)	250 (280)	500 (560)
Cd	4.4 (5)	8.9 (10)	17.8 (20)

1 Table 6-2 values should not be used as definitive guidelines for fruit and vegetable production.
2 Interpolation should be used to obtain values in CEC range 5-15.
3 Soil plow layer must be maintained at pH 6.5 or above at time of each sludge application.

651.0604 Balancing plant nutrient needs with waste application

Waste management must balance the capacity of the soils and plants to transform the chemical elements in the waste product by the amount that is applied or is residual in the system. A lack of plant nutrients in an available form for uptake can cause a deficiency in plants, and an excess of plant nutrients can cause toxicity. Both situations decrease plant growth. An excess can also find its way through the food chain and be hazardous to the consumer or the environment. Those elements that are not transformed or retained in the soil can leave the system and become a contaminant to surface and ground water.

(a) Deficiencies of plant nutrients

The deficiency of nutrients to the plants from agricultural waste application can occur by either the shortage of supplied elements contained in the material or the interference in the uptake of essential nutrients caused by the excessive supply of another. In the first case, an analysis of the waste material is needed to determine the amount of plant nutrients being supplied, and this amount is balanced with the quantity required by the crop. Using the Nutrient Management Standard (590) with a nutrient budget worksheet will assure that all essential nutrients are being supplied to the crop. For the second case, an example in the section, "Excesses of plant nutrients, total dissolved solids, and trace elements," shows the antagonism that excessive uptake of ammonium ion from manure has on the calcium ion. High levels of copper, iron, and manganese in the waste material can cause a plant deficiency of zinc caused by blockage of Zn uptake sites on the root by the other ions.

(b) Excesses of plant nutrients, total dissolved solids, and trace elements

The tolerance of plants to high levels of elements in plant tissue must also be accounted for in waste application to cropland. Heavy applications of waste can cause elevated levels of nitrates in plant tissue that can lead to nitrate poisoning of livestock consuming that foliage.

The ability to accumulate nitrates differs from plant to plant or even within cultivars of a species. Concentrations of nitrate nitrogen in plant dry matter less than 0.1 percent is considered safe to feed livestock. Large applications of waste material on tall fescue, orchardgrass, and sudangrass can cause nitrate buildup. Cattle grazing these plants can, thus, be poisoned. When the concentration of nitrate nitrogen in the dry harvested material exceeds 0.4 percent, the forage is toxic.

Animal manure releases ammonia gas upon drying. Urea contained in manure is unstable. As manure dries, the urea breaks down into ammonium. The release of gaseous NH_3 from manure can result in ammonia toxicity. Exposure of corn seeds to ammonia during the initial stages of germination can cause significant injury to the development of seedlings. High levels of NH_3 and NH_4 in the soil interferes with the uptake of the calcium ion causing plants to exhibit calcium deficiency (Hensler et al. 1970; Olsen et al. 1970). Part of the ammonium released is adsorbed on the cation exchange sites of the soil, releasing calcium, potassium, and magnesium ions into solution. High levels of these ions in the soil solution contributes to an increase in the soluble salt level as well as pH.

Proper handling of manure is necessary to prevent toxicity from occurring. Manure may contain high levels of ammonium nitrogen; up to 50 percent is in the NH_4 form. To prevent toxicity from occurring on young plant seedlings, the manure should be field spread and either immediately incorporated into the soil to adsorb the NH_4 on the cation exchange sites of the soil or allowed to air dry on the soil surface. Surface drying greatly reduces the level of ammonia by volatilization. Direct planting into the soil surface that is covered with manure, such as with no-till planting, can lead to germination problems and seedling injury unless rainfall or surface drying has lessened the amount of ammonia in the manure.

Applying manure at rates based on nitrogen requirements of the crop helps to avoid excess NH_4 buildup in the seed zone. A 0.25-inch rain or irrigation application generally is sufficient to dissipate the high concentrations of NH_4 in the seed zone.

Sidedressing of manure on corn, either by injection or surface application, has been shown to be an effective way to apply the inorganic portion (NO_3 and NH_4) of nitrogen that is quickly made available for plant growth (Klausner and Guest 1981). Injecting manure into soil conserves more of the ammonium nitrogen during periods of warm, dry weather and prevents ammonia toxicity to the growth of plants (Sutton et al. 1982).

The soluble salt content of manure and sludge is high and must be considered when these wastes are applied to cropland. The percent salt in waste may be estimated by multiplying the combined percentages of potassium, calcium, sodium, and magnesium as determined by laboratory analysis by a factor of two (USEPA 1979).

$$\%\ \text{salts} = (\%\text{K} + \%\text{Ca} + \%\text{Na} + \%\text{Mg}) \times 2$$

Under conditions where only limited rainfall and irrigation are applied, salts are not adequately leached out of the root zone and can build up high enough quantities to cause plant injury. Plants that are salt sensitive or only moderately tolerant show progressive decline in growth and yields as levels of salinity increase (figs. 6–2, 6–3, 6–4).

Some plant species are tolerant to salinity yet sensitive during germination. If manure or sludge is applied to land in areas that receive moderate rainfall or irrigation water during the growing season, soluble salts in the waste will be dispersed through the profile or leached below the root zone. If manure or sludge are applied under a moisture deficit condition, salt concentrations can build up.

Figure 6–2 Effect of soil salinity on growth of field crops

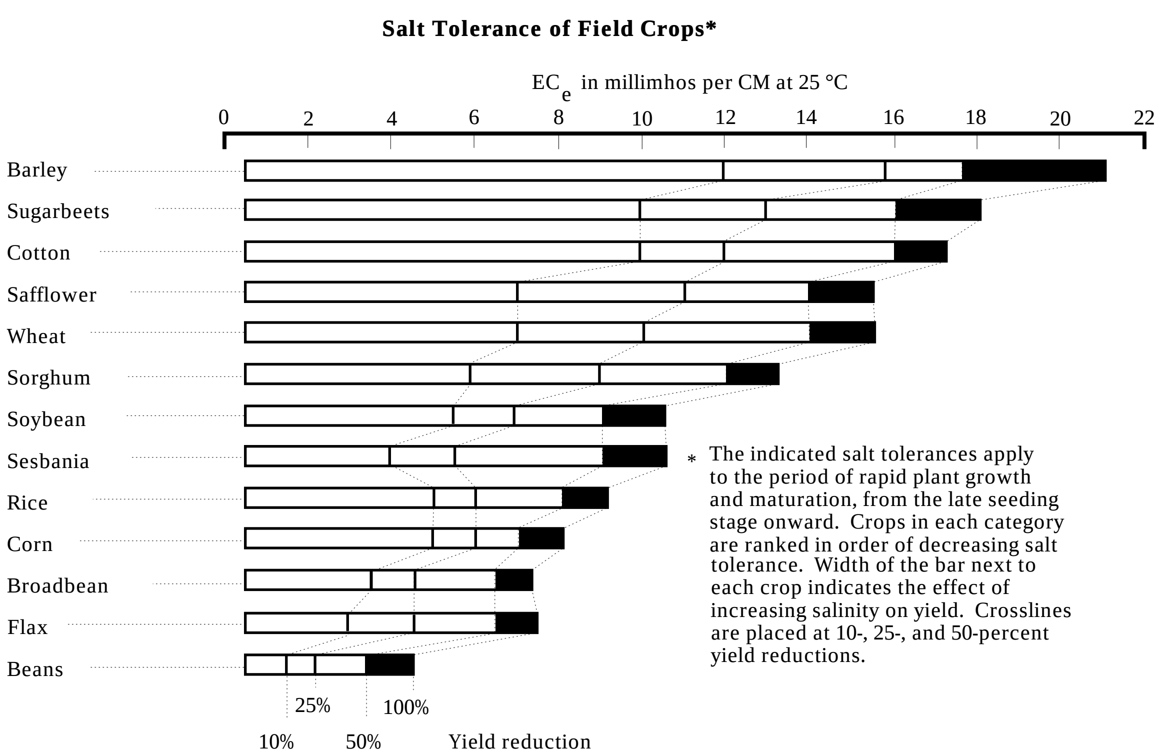
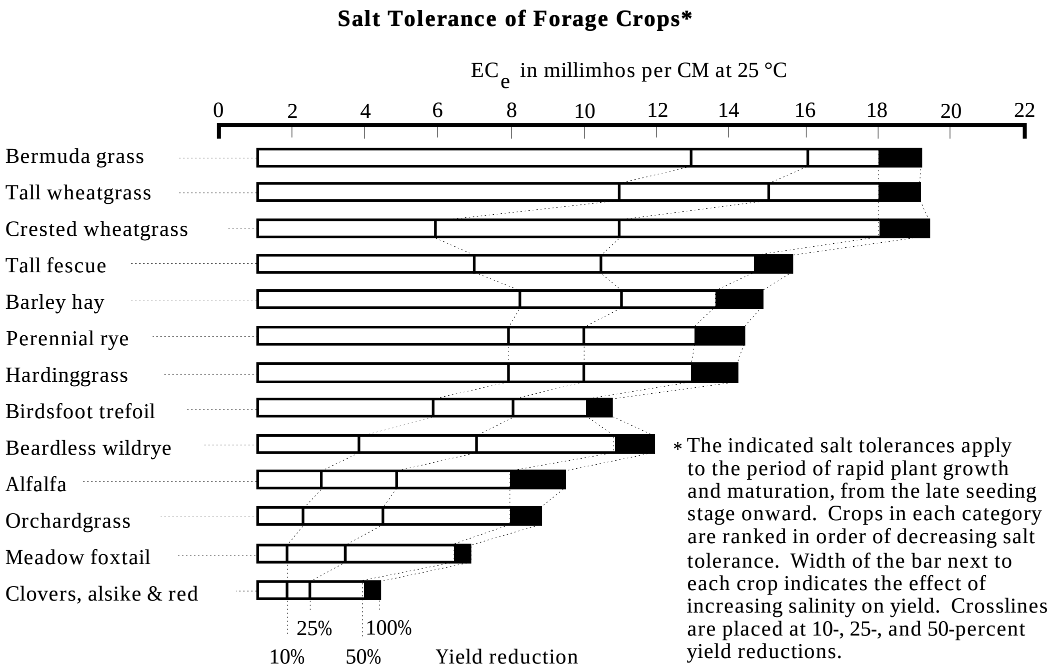
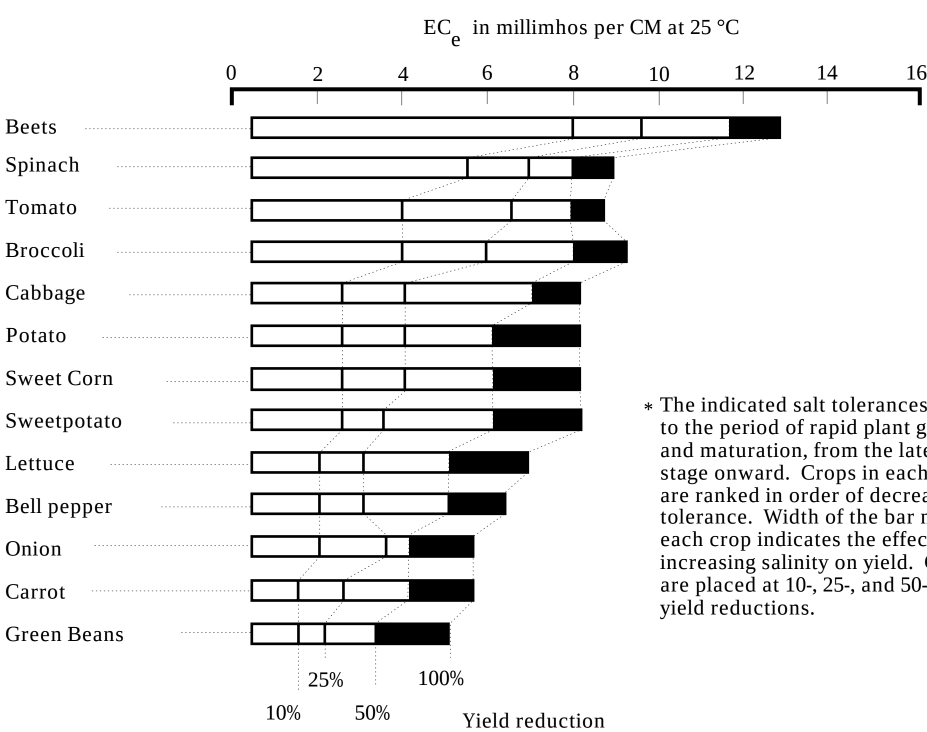


Figure 6–3 Effect of soil salinity on growth of forage crops



* The indicated salt tolerances apply to the period of rapid plant growth and maturation, from the late seeding stage onward. Crops in each category are ranked in order of decreasing salt tolerance. Width of the bar next to each crop indicates the effect of increasing salinity on yield. Crosslines are placed at 10-, 25-, and 50-percent yield reductions.

Figure 6–4 Effect of soil salinity on growth of vegetable crops



* The indicated salt tolerances apply to the period of rapid plant growth and maturation, from the late seeding stage onward. Crops in each category are ranked in order of decreasing salt tolerance. Width of the bar next to each crop indicates the effect of increasing salinity on yield. Crosslines are placed at 10-, 25-, and 50-percent yield reductions.

A soil test, the electrical conductivity of saturated paste extract, is used to measure the total salt concentration in the soil. After prolonged application of manure, the soil electrical conductivity should be tested. Conductivity values of 2 mmhos/cm or less are considered low in salts and suitable for all crops. Above values of 4 mmhos/cm, plant growth is affected except for all but the most tolerant crops (figs. 6–2, 6–3, 6–4). At these high conductivity values, irrigation amounts need to be increased to leach salts. Added water percolating through the profile may then cause concern with leaching of nitrates. Manure application rates may have to be adjusted (Stewart 1974).

Trace element toxicity is of concern with waste application on agricultural land. Animal manure can have elevated amounts of aluminum, copper, and zinc. Sewage sludge can have elevated concentrations of several elements, most notably aluminum, cadmium, chromium, copper, iron, mercury, nickel, lead, and zinc. The element and concentration in the sludge depends on the predominant industry in the service area. If wastes that have elevated levels of trace elements are applied over a long period of time at significant rates, trace element toxicity can occur on plants. Micronutrient and trace element toxicity to animals and humans can also occur where cadmium, copper, molybdenum, and selenium levels in plant tissue become elevated.

Table 6–3 lists some general crop growth symptoms and crops most sensitive to the given trace elements. If such symptoms should occur, a plant tissue test should be done to confirm which element is at fault. Many of the symptomatic signs are similar for two or more elements, making it extremely difficult to know with certainty which element is in excess from observation of outward symptoms. Much of the toxicity of such trace elements can be because of their antagonistic action against nutrient uptake and use by plants. Table 6–4 shows the interaction among elements within plants and adjacent to the plant roots.

651.0605 Application of agricultural waste

(a) Field and forage crops

Manure and sewage have been used for centuries as fertilizers and soil amendments to produce food for human and animal consumption. Generally, manure and sludges are applied to crops that are most responsive to nitrogen inputs. Field crops that are responsive include corn, sorghum, cotton, tobacco, sugar beets, and cane.

Sewage sludge should not be used on tobacco. The liming effect of the sludge can enhance the incidence of root diseases of tobacco. It can also elevate cadmium levels in tobacco leaves, rendering it unfit for marketing (USDA 1986).

Cereal grains generally do not receive fertilizer application through manure because spreading to deliver low rates of nitrogen is difficult. Small grains are prone to lodging (tipping over en masse under wet, windy conditions) because of the soft, weak cell walls derived from rapid tissue growth.

Legumes, such as alfalfa, peanuts, soybeans, and clover, benefit less by manure and sludge additions because they fix their own nitrogen. The legumes, however, use the nitrogen in waste products and produce less symbiotically fixed nitrogen. Alfalfa, a heavy user of nitrogen, can cycle large amounts of soil nitrogen from a depth of up to 6 feet. Over 500 pounds per acre of nitrogen uptake by alfalfa has been reported (Schuman & Elliott 1978; Schertz & Miller 1972).

The great danger of using manure and sludges on legume forages is that the added nitrogen may promote the growth of the less desirable grasses that are in the stand. This is caused primarily by introducing another source of nitrogen, but it can also be a result of the physical smothering of legume plants by heavy application cover of manure.

Grass tetany, a serious and often fatal disorder in lactating ruminants, is caused by a low magnesium content in rapidly growing cool season grasses. Cattle grazing on magnesium deficient forage develop health problems. High concentrations of nitrogen and potassium in manure applications to the forages aggravate the situation. Because of the high levels of available nitrogen and potassium in manure, early season applications on mixed grass-legume forages should be avoided until the later-growing legume is flourishing because legumes contain higher concentrations of magnesium than grasses.

Table 6–3 General effects of trace element toxicity on common crops (Kabata & Pendias 1984)

Element	Symptoms	Sensitive crop
Al	Overall stunting, dark green leaves, purpling of stems, death of leaf tips, and coralloid and damaged root system.	Cereals.
As	Red-brown necrotic spots on old leaves, yellowing and browning of roots, depressed tillering.	(No information.)
B	Margin or leaf tip chlorosis, browning of leaf points, decaying growing points, and wilting and dying-off of older leaves.	Cereals, potatoes, tomatoes, cucumbers, sunflowers, mustard.
Cd	Brown margin of leaves, chlorosis, reddish veins and petioles, curled leaves, and brown stunted roots.	Legumes (bean, soybean), spinach radish, carrots, and oats.
Co	Interveinal chlorosis in new leaves followed by induced Fe chlorosis and white leaf margins and tips, and damaged root tips.	(No information.)
Cr	Chlorosis of new leaves, injured root growth.	(No information.)
Cu	Dark green leaves followed by induced Fe chlorosis, thick, short, or barbed-wire roots, depressed tillering.	Cereals and legumes, spinach, citrus, seedlings, and gladiolus.
F	Margin and leaf tip necrosis; chlorotic and red-brown points of leaves.	Gladiolus, grapes, fruit trees, and pine trees.
Fe	Dark green foliage, stunted growth of tops and roots, dark brown to purple leaves of some plants ("bronzing" disease of rice).	Rice and tobacco.
Hg	Severe stunting of seedlings and roots, leaf chlorosis and browning of leaf points.	Sugarbeets, corn, and roses.
Mn	Chlorosis and necrotic lesions on old leaves, blackish-brown or red necrotic spots, accumulation of MnO_2 particles in epidermal cells, drying tips of leaves, and stunted roots.	Cereals, legumes, potatoes, and cabbage.
Mo	Yellowing or browning of leaves, depressed root growth, depressed tillering.	Cereals.
Ni	Interveinal chlorosis in new leaves, gray-green leaves, and brown and stunted roots.	Cereals.
Pb	Dark green leaves, wilting of older leaves, stunted foliage, and brown short roots.	(No information.)
Rb	Dark green leaves, stunted foliage, and increasing amount of shoots.	(No information.)
Se	Interveinal chlorosis or black spots at Se content at about 4 mg/L and complete bleaching or yellowing of younger leaves at higher Se content; pinkish spots on roots.	(No information.)
Zn	Chlorotic and necrotic leaf tips, interveinal chlorosis in new leaves, retarded growth of entire plant, injured roots resemble barbed wire.	Cereals and spinach.

Perennial grasses benefit greatly by the addition of manure and sludges. Many are selected as vegetative filters because of their efficient interception and uptake of nutrients and generally longer active growing season. Others produce large quantities of biomass and thus can remove large amounts of nutrients, especially nitrogen, from the soil-plant system.

Bermudagrass pastures in the South have received annual rates of manure that supply over 400 pounds of nitrogen per acre without experiencing excessive nitrate levels in the forage. However, runoff and leaching potentials are high with these application rates, and they must be considered in the utilization plan.

Grass sods also accumulate nitrogen. An experiment in England carried out for 300 years at Rothamsted showed a steady increase in soil nitrogen for about 125 years before leveling off when an old plowed field was retired to grass (Wild 1988). However, where waste is spread on the soil surface, any ammonia nitrogen in the waste generally is lost to the air as a gas unless immediately incorporated.

Grass fields used for pasture or hay must have waste spread when the leaves of the plants are least likely to be contaminated with manure. If this is done, the grass quality is not lessened when harvested mechanically or grazed by animals (Simpson 1986).

Spreading wastes immediately after harvest and before regrowth is generally the best time for hay fields and pastures in a rotation system. This is especially important where composted sludge is applied on pasture at rates of more than 30 tons per acre. Cattle and sheep ingesting the compost inadvertently can undergo copper deficiency symptoms (USDA 1986).

Some reports show that manure applied to the soil surface has caused ammonium toxicity to growing crops (Klausner and Guest 1981). Young corn plants 8 inches high showed ammonia burn after topdressing with dairy manure during a period of warm, dry weather. The symptom disappeared after a few days with no apparent damage to the crop. This is very similar to corn burn affected during sidedressing by anhydrous ammonia. Liquid manure injected between corn rows is toxic to plant roots and causes temporary reduction in crop growth. Warming soil conditions dissipate the high ammonium levels, converting the ammonium to nitrates, and alleviate the temporary toxic conditions (Sawyer and Hoeft 1990).

Table 6–4 Interaction among elements within plants and adjacent to plant roots

Major elements	Antagonistic elements	Synergistic elements	**Trace elements**	Antagonistic elements	Synergistic elements
Ca	Al, B, Ba, Be, Cd, Co, Cr, Cs, Cu, F, Fe, Li, Mn, Ni, Pb, Sr, Zn	Cu, Mn, Zn	Cu	Cd, Al, Zn, Se, Mo, Fe, Ni, Mn	Ni, Mn, Cd
			Zn	Cd, Se, Mn, Fe, Ni, Cu	Ni, Cd
Mg	Al, Be, Ba, Cr, Mn, F, Zn, Ni, Co, Cu, Fe	Al, Zn	Cd	Zn, Cu, Al, Se, Mn, Fe, Ni	Cu, Zn, Pb, Mn, Fe, N
P	Al, As, B, Be, Cd, Cr, Cu, F, Fe, Hg, Mo, Mn, Ni, Pb, Rb, Se, Si, Sr, Zn	Al, B, Cu, F, Fe, Mn, Mo, Zn	B	Si, Mo, Fe	Mo, Fe
			Al	Cu, Cd	(No evidence.)
			Pb	---	Cd
			Mn	Cu, Zn, Mo, Fe, Ar, Cr, Fe, Co, Cd, Al, Ni, Ar, Se	Cu, Cd, Al, Mo
K	Al, B, Hg, Cd, Cr, F, Mo, Mn, Rb	(No evidence.)	Fe	Zn, Cr, Mo, Mn, Co, Cu, Cd, B, Si	Cd, B
S	As, Ba, Fe, Mo, Pb, Se	F, Fe			
N	B, F, Cu	B, Cu, Fe, Mo	Mo	Cu, Mn, Fe, B	Mn, B. Si
Cl	Cr, I	(No evidence.)	Co	Mn, Fe	(No evidence.)
			Ni	Mn, Zn, Cu, Cd	Cu, Zn, Cd

(b) Horticultural crops

Vegetables and fruits benefit from applications of wastes; however, care must be taken because produce can be fouled or disease can be spread. Surface application of wastes to the soil around fruit trees will not cause either problem, but spray applications of liquid waste could.

Manure or sludge applied and plowed under before planting will not cause most vegetables to be unduly contaminated with disease organisms as long as they are washed and prepared according to good food industry standards. However, the scab disease may be promoted on the skin of potatoes with the addition of organic wastes. Well rotted or composted manure can be used to avoid excessive scabbing if it is plowed under before the potatoes are planted (Martin and Leonard 1949). Additional guidelines for the use of municipal sludge are in table 6–5.

Table 6–5 Summary of joint EPA/FDA/USDA guidelines for sludge application for fruit and vegetable production (USEPA 1983)

Annual and cumulative Cd rates:	Annual rate should not exceed 0.5 kg/ha (0.446 lb/ac). Cumulative Cd loadings should not exceed 5, 10, or 20 kg/ha, depending on CEC values of <5, 5 to 15, and >15 meq/100g, respectively, and soil pH.
Soil pH:	Soil pH (plow zone - top 6 inches) should be 6.5 or greater at time of each sludge application.
PCB's:	Sludges that have PCB concentrations of more than 10 ppm should be incorporated into the soil.
Pathogen reduction:	Sludge should be treated by pathogen reduction process before soil application. A waiting period of 12 to 18 months before a crop is grown may be required, depending on prior sludge processing and disinfection.
Use of high-quality sludge:	High-quality sludge should not contain more than 25 ppm Cd, 1,000 ppm Pb, and 10 ppm PCB (dry weight basis).
Cumulative lead (Pb) application rate:	Cumulative Pb loading should not exceed 800 kg/ha (714 lb/ac).
Pathogenic organisms:	A minimum requirement is that crops to be eaten raw should not be planted in sludge-amended fields within 12 to 18 months after the last sludge application. Further assurance of safe and wholesome food products can be achieved by increasing the time interval to 36 months. This is especially warranted in warm, humid climates.
Physical contamination and filth:	Sludge should be applied directly to soil and not directly to any human food crop. Crops grown for human consumption on sludge-amended fields should be processed using good food industry practices, especially for root crops and low-growing fresh fruits and vegetables.
Soil monitoring:	Soil monitoring should be performed on a regular basis, at least annually for pH. Every few years, soil tests should be run for Cd and Pb.
Choice of crop type:	Plants that do not accumulate heavy metals are recommended.

(c) Vegetated filter strips for agricultural waste treatment

Vegetated filter strips are designed strips or areas of vegetation growing downgradient of an animal production facility or cropland where animal waste has been applied. The strips can filter nutrients, sediment, organics, agrichemicals, and pathogens from runoff received from the contributing areas.

Four processes are involved in the removal of the elements in the run-on water. The first process is deposition of sediment (solid material) in the strip. A vegetated filter strip is composed of grasses or other dense vegetation that offers resistance to shallow overland flow. The decrease in flow velocity at the upslope edge of the vegetated filter strip greatly reduces the sediment transport capacity, and suspended solids are deposited.

In the second process the vegetation provides for surface run-on water to enter the soil profile. Once infiltrated into the soil, the elements are entrapped by the chemical, physical, and biological processes and are transformed into plant nutrients or organic components of the soil.

In the third process some soluble nutrients moving with the run-on water can be directly absorbed through the plant leaves and stems, and in the fourth, the thick, upright vegetation adheres solid particles that are being carried in the runoff, physically filtering them out.

In all of the processes, the nutrients taken from the run-on water by the plants transform a potential pollutant into vegetative biomass that can be used for forage, fiber, or mulch material.

Results from recent research show that vegetated filter strips have a wide range of effectiveness (Adam et al. 1986; Dillaha et at. 1988; Doyle et al. 1977; Schwer and Clausen 1989; Young et al. 1980). Variations in effectiveness are associated with individual site conditions, both the vegetated filter strip site and contributing area.

Land slope, soils, land use and management, climate, vegetation type and density, application rates for sites periodically loaded, and concentration and characteristics of constituents in incoming water are all important site characteristics that influence effectiveness. Operation and management of the contributing area, along with maintenance of the vegetated filter strip influence the ability of the total system to reduce the concentration and amount of contaminants contained in the runoff from the site. Knowledge of site variables is essential before making planning decisions about how well vegetated filter strips perform.

Research and operation sites exhibit certain characteristics that should be considered in planning a vegetated filter strip:

- Sheet flow must be maintained. Concentrated flow should be avoided unless low velocity grass waterways are used.
- Hydraulic loading must be carefully controlled to maintain desired depth of flow.
- Application of process generated wastewater must be periodically carried out to allow rest periods for the vegetated filter strip. Storage of wastewater is essential for rest periods and for climatic influences.
- Unless infiltration occurs, removal of soluble constituents from the run-on water will be minimal.
- Removal of suspended solids and attached constituents from the run-on can be high, in the range of 60 to 80 percent for properly installed and maintained strips.
- Vegetated filter strips should not be used as a substitute for other appropriate structural and management practices. They generally are not a stand-alone practice.
- Maintenance that includes proper care of the vegetation and removal of the accumulated solids must be performed.
- Proper siting is essential to assure uniform slopes can be installed and maintained along and perpendicular to the flow path.

The criteria for planning, design, implementation, and operation and maintenance of vegetated filter strips for livestock operations and manure application sites are in Conservation Practice Standard 393, "Filter Strip."

(d) Forest land for agricultural waste treatment

Forest land provides an area for recycling agricultural waste. Wastewater effluent has been applied to some forest sites over extended periods of time with good nutrient removal efficiency and minimal impact on surface or ground water. On most sites the soil is covered with layers, some several inches thick, of organic material. This material can efficiently remove sediment and phosphorus from the effluent. Nitrogen in the form of nitrates is partly removed from the wastewater in the top few feet of the soil, and the added fertility contributes to increased tree and understory growth. Caution must be taken not to over apply water that will leach nitrates out of the root zone and down toward the ground water. Digested sludge also has been applied to forest.

Considerable amounts of nutrients are taken up by trees. Many of these nutrients are redeposited and recycled annually in the leaf litter. Leaves make up only 2 percent of the total dry weight of northern hardwoods. Harvesting trees with leaves on increases the removal of plant nutrients by the following percentages over that for trees without leaves:

Calcium	= 12%
Potassium	= 15%
Phosphorus	= 4%
Nitrogen	= 19%

Whole tree harvesting of hardwoods removes almost double the nutrients removed when only the stemwood is taken. Stemwood, the usual harvested bole or log taken from the tree for lumber, makes up about 80 percent of the aboveground biomass (Hornbeck and Kropelin 1982).

Riparian forest buffers are effective ecosystems between utilization areas and water bodies to control transport of contaminants from nonpoint sources (Lowrance et al. 1985). No specific literature has been reported on using these areas for utilization of nutrients in agricultural waste. These areas should be maintained to entrap nutrients in runoff and protect water bodies. They should not be used for waste spreading.

Only 10 percent of the nitrogen in a 45-year-old Douglas fir forest ecosystem is in the trees. The greater part of the nutrient sink in a coniferous forest is in the tree roots and soil organic matter. Although nitrogen uptake in forests exceeds 100 pounds per acre per year, less than 20 percent net is accumulated in eastern hardwood forest. The greater part of the assimilation is recycled from the soil and litter. Continued application rates of agricultural waste should be adjusted to meet the long-term sustainable need of the forest land, which generally is a half to two thirds that of the annual row crops (Keeney 1980).

651.0606 Nutrient removal by harvesting of crops

The nutrient content of a plant depends on the amount of nutrients available to the plant and on the environmental growing condition. The critical level of nutrient concentration of the dry harvested material of the plant leaf is about 2 percent nitrogen, 0.25 percent phosphorus, and 1 percent potassium. Where nutrients are available in the soil in excess of plant sufficiency levels, the percentages can more than double.

In forage crops, the percent composition for nitrogen can range from 1.2 to 2.8 percent, averaging around 2 percent of the dry harvested material of the plant. The concentrations can reach as high as 4.5 percent, however, if the soil system has high levels of nitrogen (Walsh and Beaton 1973).

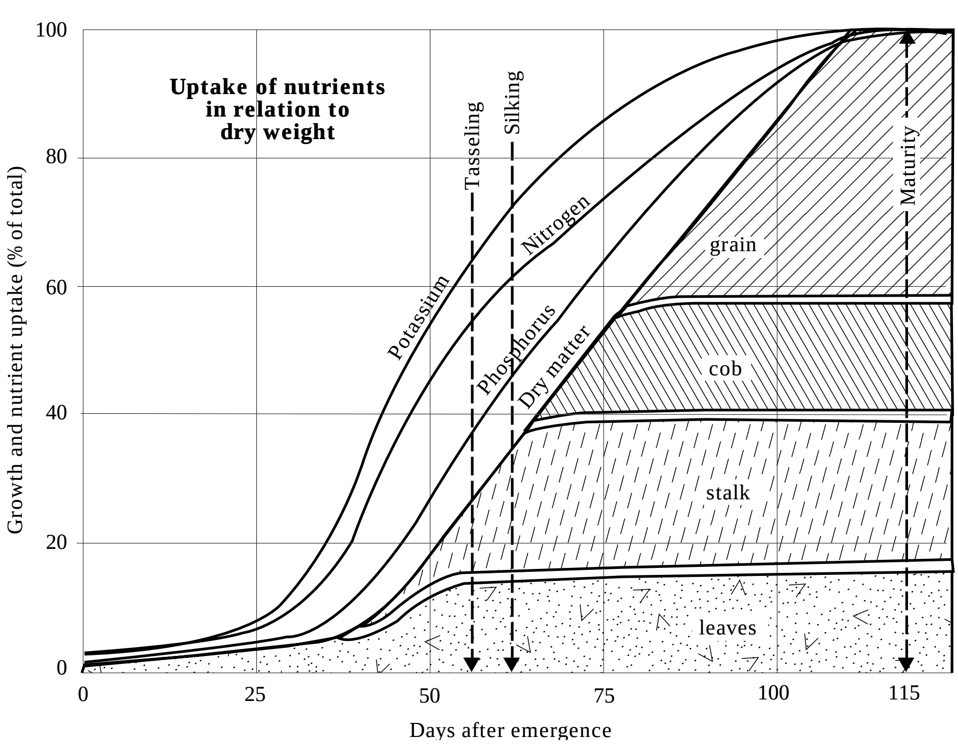
The total uptake of nutrients by crops from agricultural waste applications increases as the crop yields increase, and crop yields for the most part increase with increasing soil nutrients, provided toxic levels are not reached or nutrient imbalances do not occur. The total nutrient uptake continues to increase with yield, but the relation does not remain a constant linear relationship.

Two important factors that affect nutrient uptake and removal by crop harvest are the percent nutrient composition in the plant tissue and the crop biomass yield. In general, grasses contain their highest percentage of nutrients, particularly nitrogen, during the rapid growth stage of stem elongation and leaf growth.

Nitrogen uptake in grasses, like corn (fig. 6–5), follows an S-shaped uptake curve with very low uptake the first 30 days of growth, but rises sharply until flowering, then decreases with maturity.

Harvesting the forage before it flowers would capture the plant's highest percent nutrient concentration. Multiple cuttings during the growing season maximizes dry matter production. A system of two or three harvests per year at the time of grass heading would optimize the dry matter yield and plant tissue concentration, thus maximizing nutrient uptake and removal.

Figure 6–5 Growth and nutrient uptake by corn (adapted from Hanaway 1962)



(a) Nutrient uptake calculation

Table 6–6 can be used to calculate the approximate nutrient removal by agricultural crops. Typical crop yields are given only as default values and should be selected only in lieu of local information.

1. Select the crop or crops that are to be grown in the cropping sequence.
2. Determine the plant nutrient percentage of the crop to be harvested as a percentage of the dry or wet weight depending on the crop value given in table 6–6.
3. Determine the crop yield in pounds per acre. Weight to volume conversion are given.
4. Multiply the crop yield by the percentage of nutrient in the crop.

The solution is pounds per acre of nutrients removed in the harvested crop.

(b) Nutrient uptake example

Corn and alfalfa are grown in rotation and harvested as grain and silage corn and alfalfa hay. Follow the above steps to calculate the nutrient taken up and removed in the harvested crop.

1. Crops to be grown: corn and alfalfa

2. Plant nutrient percentage in harvested crop (table 6–6):

   corn grain: 1.61% nitrogen
   0.28% phosphorus
   0.40% potassium

   corn silage: 1.10% nitrogen
   0.25% phosphorus
   1.09% potassium

   alfalfa: 2.25% nitrogen
   0.22% phosphorus
   1.87% potassium

3. Crop yield taken from local data base:

   corn grain: 130 bu/ac @ 56 lb/bu
   = 7,280 lb.

   corn silage: 22 tons/ac @ 2,000 lb/ton @ 35% dm
   = 15,400 lb

   alfalfa hay: 6 tons/ac @ 2,000 lb/ton
   = 12,000 lb

4. Multiplying percent nutrients contained in the crop harvested by the dry matter yield:

   corn grain:
   1.61% N x 7,280 lb = 117 lb N
   0.28% P x 7,280 lb = 20 lb P
   0.40% K x 7,280 lb = 29 lb K

   corn silage:
   1.10% N x 15,400 lb = 169 lb N
   0.25% P x 15,400 lb = 39 lb P
   1.09% K x 15,400 lb = 168 lb K

   alfalfa:
   2.25% N x 12,000 lb = 270 lb N
   0.22% P x 12,000 lb = 26 lb P
   1.87% K x 12,000 lb = 224 lb K

Nutrient values are given as elemental P and K. The conversion factors for phosphates and potash are:

$$\text{lb P} \times 2.3 = \text{lb } P_2O_5$$
$$\text{lb K} \times 1.2 = \text{lb } K_2O$$

Under alfalfa, nitrogen includes that fixed symbiotically from the air by alfalfa.

Table 6–6 shows the nutrient concentrations that are average values derived from plant tissue analysis values, which can have considerable range because of climatic conditions, varietal differences, soil conditions, and soil fertility status. Where available, statewide or local data should be used in lieu of the table values.

Table 6–6 Plant nutrient uptake by specified crop and removed in the harvested part of the crop (Kilmer 1982; Morrison 1956; Sanchez 1976; USDA 1985)

Crop	Dry wt. lb/bu	Typical yield/acre plant part	Average concentration of nutrients (%) N	P	K	Ca	Mg	S	Cu	Mn	Zn
Grain crops			% of the dry harvested material								
Barley	48	50 bu	1.82	0.34	0.43	0.05	0.10	0.16	0.0016	0.0016	0.0031
		1 T. straw	0.75	0.11	1.25	0.40	0.10	0.20	0.0005	0.0160	0.0025
Buckwheat	48	30 bu	1.65	0.31	0.45	0.09			0.0009	0.0034	
		0.5 T. straw	0.78	0.05	2.26	1.40		0.01			
Corn	56	120 bu	1.61	0.28	0.40	0.02	0.10	0.12	0.0007	0.0011	0.0018
		4.5 T. stover	1.11	0.20	1.34	0.29	0.22	0.16	0.0005	0.0166	0.0033
Oats	32	80 bu	1.95	0.34	0.49	0.08	0.12	0.20	0.0012	0.0047	0.0020
		2 T. straw	0.63	0.16	1.66	0.20	0.20	0.23	0.0008	0.0030	0.0072
Rice	45	5,500 lb	1.39	0.24	0.23	0.08	0.11	0.08	0.0030	0.0022	0.0019
		2.5 T. straw	0.60	0.09	1.16	0.18	0.10			0.0316	
Rye	56	30 bu	2.08	0.26	0.49	0.12	0.18	0.42	0.0012	0.0131	0.0018
		1.5 T. straw	0.50	0.12	0.69	0.27	0.07	0.10	0.0300	0.0047	0.0023
Sorghum	56	60 bu	1.67	0.36	0.42	0.13	0.17	0.17	0.0003	0.0013	0.0013
		3 T. stover	1.08	0.15	1.31	0.48	0.30	0.13		0.0116	
Wheat	60	40 bu	2.08	0.62	0.52	0.04	0.25	0.13	0.0013	0.0038	0.0058
		1.5 T. straw	0.67	0.07	0.97	0.20	0.10	0.17	0.0003	0.0053	0.0017
Oil crops			% of the dry harvested material								
Flax	56	15 bu	4.09	0.55	0.84	0.23	0.43	0.25		0.0061	
		1.75 T. straw	1.24	0.11	1.75	0.72	0.31	0.27			
Oil palm		22,000 lb	1.13	0.26	0.16	0.19	0.09		0.0043	0.0225	
		5 T. fronds & stems	1.07	0.49	1.69		0.36				
Peanuts	22-30	2,800 lb	3.60	0.17	0.50	0.04	0.12	0.24	0.0008	0.0040	
		2.2 T. vines	2.33	0.24	1.75	1.00	0.38	0.36		0.0051	
Rapeseed	50	35 bu	3.60	0.79	0.76		0.66				
		3 T. straw	4.48	0.43	3.37	1.47	0.06	0.68	0.0001	0.0008	
Soybeans	60	35 bu	6.25	0.64	1.90	0.29	0.29	0.17	0.0017	0.0021	0.0017
		2 T. stover	2.25	0.22	1.04	1.00	0.45	0.25	0.0010	0.0115	0.0038
Sunflower	25	1,100 lb	3.57	1.71	1.11	0.18	0.34	0.17		0.0022	
		4 T. stover	1.50	0.18	2.92	1.73	0.09	0.04		0.0241	

Table 6–6 Plant nutrient uptake by specified crop and removed in the harvested part of the crop — Continued

Crop	Dry wt. lb/bu	Typical yield/acre plant part	N	P	K	Ca	Mg	S	Cu	Mn	Zn
			Average concentration of nutrients (%)								
Fiber crops		% of the dry harvested material									
Cotton		600 lb. lint & 1,000 lb seeds	2.67	0.58	0.83	0.13	0.27	0.20	0.0040	0.0073	0.0213
		burs & stalks	1.75	0.22	1.45	1.40	0.40	0.75			
Pulpwood		98 cords	0.12	0.02	0.06		0.02				
		bark, branches	0.12	0.02	0.06		0.02				
Forage crops		% of the dry harvested material									
Alfalfa		4 tons	2.25	0.22	1.87	1.40	0.26	0.24	0.0008	0.0055	0.0053
Bahiagrass		3 tons	1.27	0.13	1.73	0.43	0.25	0.19			
Big bluestem		3 tons	0.99	0.85	1.75		0.20				
Birdsfoot trefoil		3 tons	2.49	0.22	1.82	1.75	0.40				
Bluegrass-pastd.		2 tons	2.91	0.43	1.95	0.53	0.23	0.66	0.0014	0.0075	0.0020
Bromegrass		5 tons	1.87	0.21	2.55	0.47	0.19	0.19	0.0008	0.0052	
Clover-grass		6 tons	1.52	0.27	1.69	0.92	0.28	0.15	0.0008	0.0106	
Dallisgrass		3 tons	1.92	0.20	1.72	0.56	0.40				
Guineagrass		10 tons	1.25	0.44	1.89		0.43	0.20			
Bermudagrass		8 tons	1.88	0.19	1.40	0.37	0.15	0.22	0.0013		
Indiangrass		3 tons	1.00	0.85	1.20	0.15					
Lespedeza		3 tons	2.33	0.21	1.06	1.12	0.21	0.33		0.0152	
Little bluestem		3 tons	1.10	0.85	1.45		0.20				
Orchardgrass		6 tons	1.47	0.20	2.16	0.30	0.24	0.26	0.0017	0.0078	
Pangolagrass		10 tons	1.30	0.47	1.87		0.29	0.20			
Paragrass		10.5 tons	0.82	0.39	1.59	0.39	0.33	0.17			
Red clover		2.5 tons	2.00	0.22	1.66	1.38	0.34	0.14	0.0008	0.0108	0.0072
Reed canarygrass		6.5 tons	1.35	0.18		0.36					
Ryegrass		5 tons	1.67	0.27	1.42	0.65	0.35				
Switchgrass		3 tons	1.15	0.10	1.90	0.28	0.25				
Tall fescue		3.5 tons	1.97	0.20	2.00	0.30	0.19				
Timothy		2.5 tons	1.20	0.22	1.58	0.36	0.12	0.10	0.0006	0.0062	0.0040
Wheatgrass		1 ton	1.42	0.27	2.68	0.36	0.24	0.11			
Forest		% of the dry harvested material									
Leaves			0.75	0.06	0.46						
Northern hardwoods		50 tons	0.20	0.02	0.10	0.29					
Douglas fir		76 tons	0.16								

Table 6–6 Plant nutrient uptake by specified crop and removed in the harvested part of the crop — Continued

Crop	Dry wt. lb/bu	Typical yield/acre plant part	N	P	K	Ca	Mg	S	Cu	Mn	Zn
			Average concentration of nutrients (%)								
Fruit crops		% of the fresh harvested material									
Apples		12 tons	0.13	0.02	0.16	0.03	0.02	0.04	0.0001	0.0001	0.0001
Bananas		9,900 lb.	0.19	0.02	0.54	0.23	0.30				
Cantaloupe		17,500 lb.	0.22	0.09	0.46		0.34				
Coconuts		0.5 tons–dry copra	5.00	0.60	3.33	0.21	0.36	0.34	0.0010		0.0076
Grapes		12 tons	0.28	0.10	0.50		0.04				
Oranges		54,000 lb.	0.20	0.02	0.21	0.06	0.02	0.02	0.0004	0.0001	0.0040
Peaches		15 tons	0.12	0.03	0.19	0.01	0.03	0.01			0.0010
Pineapple		17 tons	0.43	0.35	1.68	0.02	0.18	0.04			
Tomatoes		22 tons	0.30	0.04	0.33	0.02	0.03	0.04	0.0002	0.0003	0.0001
Silage crops		% of the dry harvested material									
Alfalfa haylage (50% dm)		10 wet/5 dry	2.79	0.33	2.32	0.97	0.33	0.36	0.0009	0.0052	
Corn silage (35% dm)		20 wet/7 dry	1.10	0.25	1.09	0.36	0.18	0.15	0.0005	0.0070	
Forage sorghum (30% dm)		20 wet/6 dry	1.44	0.19	1.02	0.37	0.31	0.11	0.0032	0.0045	
Oat haylage (40% dm)		10 wet/4 dry	1.60	0.28	0.94	0.31	0.24	0.18			
Sorghum-sudan (50% dm)		10 wet/5 dry	1.36	0.16	1.45	0.43	0.34	0.04		0.0091	
Sugar crops		% of the fresh harvested material									
Sugarcane		37 tons	0.16	0.04	0.37	0.05	0.04	0.04			
Sugar beets		20 tons	0.20	0.03	0.14	0.11	0.08	0.03	0.0001	0.0025	
tops			0.43	0.04	1.03	0.18	0.19	0.10	0.0002	0.0010	
Tobacco		% of the dry harvested material									
All types		2,100 lb.	3.75	0.33	4.98	3.75	0.90	0.70	0.0015	0.0275	0.0035
Turf grass		% of the dry harvested material									
Bluegrass		2 tons	2.91	0.43	1.95	0.53	0.23	0.66	0.0014	0.0075	0.0020
Bentgrass		2.5 tons	3.10	0.41	2.21	0.65	0.27	0.21			
Bermudagrass		4 tons	1.88	0.19	1.40	0.37	0.15	0.22	0.0013		

Table 6–6 Plant nutrient uptake by specified crop and removed in the harvested part of the crop — Continued

Crop	Dry wt. lb/bu	Typical yield/acre plant part	Average concentration of nutrients (%) N	P	K	Ca	Mg	S	Cu	Mn	Zn
Vegetable crops			% of the fresh harvested material								
Bell peppers		9 tons	0.40	0.12	0.49		0.04				
Beans, dry		0.5 ton	3.13	0.45	0.86	0.08	0.08	0.21	0.0008	0.0013	0.0025
Cabbage		20 tons	0.33	0.04	0.27	0.05	0.02	0.11	0.0001	0.0003	0.0002
Carrots		13 tons	0.19	0.04	0.25	0.05	0.02	0.02	0.0001	0.0004	
Cassava		7 tons	0.40	0.13	0.63	0.26	0.13				
Celery		27 tons	0.17	0.09	0.45						
Cucumbers		10 tons	0.20	0.07	0.33		0.02				
Lettuce (heads)		14 tons	0.23	0.08	0.46						
Onions		18 tons	0.30	0.06	0.22	0.07	0.01	0.12	0.0002	0.0050	0.0021
Peas		1.5 tons	3.68	0.40	0.90	0.08	0.24	0.24			
Potatoes		14.5 tons	0.33	0.06	0.52	0.01	0.03	0.03	0.0002	0.0004	0.0002
Snap beans		3 tons	0.88	0.26	0.96	0.05	0.10	0.11	0.0005	0.0009	
Sweet corn		5.5 tons	0.89	0.24	0.58		0.07	0.06			
Sweet potatoes		7 tons	0.30	0.04	0.42	0.03	0.06	0.04	0.0002	0.0004	0.0002
Table beets		15 tons	0.26	0.04	0.28	0.03	0.02	0.02	0.0001	0.0007	
Wetland plants			% of the dry harvested material								
Cattails		8 tons	1.02	0.18							
Rushes		1 ton	1.67								
Saltgrass		1 ton	1.44	0.27	0.62						
Sedges		0.8 ton	1.79	0.26		0.66					
Water hyacinth				3.65	0.87	3.12					
Duckweed			3.36	1.00	2.13						
Arrowweed			2.74								
Phragmites			1.83	0.10	0.52						

651.0607 References

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Exhibit 30.02

This exhibit was not previously submitted in November 2023

Texas proposes first new rules for oilfield waste in 40 years

> While environmentalists say the new rules don't do enough to protect groundwater, oil and gas operators are contesting stricter requirements for waste pits near wells.

BY MARTHA PSKOWSKI, **INSIDE CLIMATE NEWS** SEPT. 9, 2024 5 AM CENTRAL **SHARE**

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Texas is inching closer to adopting revised oil and gas waste management rules for the first time in four decades.

The Railroad Commission of Texas announced the draft rule at its Aug. 15 meeting and is now soliciting public comment. The rule regulates a range of disposal sites for oil and gas drilling wastes, from pits dug next to drilling rigs to large commercial facilities managing toxic waste from numerous drillers. Waste streams that fall under the rule include drilling mud, sludge, cuttings and produced water.

The rule also aims to encourage more recycling of the drilling wastewater, which can be five to eight times saltier than ocean water and, like other oilfield waste, is often laced with fracking chemicals, hazardous compounds such as arsenic, benzene and toluene.

The existing waste rule was adopted in 1984, long before fracking revolutionized the oil and gas industry. Fracking has increased the volume of oilfield waste and changed its composition. In Texas, waste pits have been linked to at least six cases of groundwater contamination and hundreds of violations of state rules.

While the need to modernize the Railroad Commission's rules is clear, the process ha proved contentious. A task force with members of the oil industry and consultants m two years to provide recommendations before the Railroad Commission released an informal draft to the public in October 2023. That round of public comments informed the updated draft released last month.

Commission Shift, a nonprofit organization focused on reforming oil and gas oversight in Texas, applauded some provisions of the latest draft, such as requiring operators to register waste pits with regulators. But the organization warned that the proposal does not provide enough protections for groundwater.

Karr Ingham, president of the Texas Alliance of Energy Producers, said his group raised concerns that provisions in the informal draft would be "unworkable" and too costly for smaller independent oil and gas companies.

"I believe a number of the changes that were made do address those concerns," Ingham said in an interview. "Yes, we're much more comfortable with the current draft than that initial draft."

The agency is now accepting written comments until Oct. 15 after extending the original deadline of Sept. 30. The Railroad Commission proposes that the new regulation, which would replace Statewide Rule 8, go into effect July 1, 2025.

"The proposed rules include a combination of strategies to protect groundwater from pollution, including engineering and design controls, groundwater monitoring, and closure standards," Railroad Commission spokesperson Patty Ramon said in an email. "In addition, the design and operational standards become more strict as waste volume increases, and also considers factors such as time in the ground, and proximity to groundwater."

Rule covers several oil and gas waste streams

While drilling an oil or gas well, oily waste, known as mud and cuttings, return to the surface. The operator digs an earthen pit alongside the rig to dispose of this waste. The pit remains open while the well is drilled and then closed once the well is complete, permanently burying the waste underground.

When these pits meet certain Railroad Commission requirements, they are automatically permitted. These are known as authorized pits or reserve pits. Other types of commercial waste pits require an individual permit under the draft rule.

The draft rule only requires liners in reserve pits when groundwater is within 50 feet e bottom of the pit. These pits cannot be in a 100-year floodplain but otherwise have no setback requirements from houses and water wells. There is no limit on how close the bottom of the reserve pit can be to the underlying groundwater and no groundwater monitoring required. However, for the first time, operators will be required to register the location of their reserve pits with the Railroad Commission.

Commercial pits have more stringent requirements for liners, groundwater monitoring and setbacks from water wells in the draft rule.

Fracking has increased the volume of drilling waste, according to law firm Baker Botts. The contents of the waste have also changed. While operators originally used water-based drilling mud, many now use oil-based mud to drill horizontal wells for fracking. The cuttings that come to the surface can contain diesel fuel and other chemicals. Drilling waste, despite containing harmful chemicals, is largely exempt from federal regulations for hazardous waste under the Resource Conservation and Recovery Act.

A separate section of the draft rule covers commercial facilities that handle waste from drilling companies. The rule also governs commercial recycling facilities that process the waste for reuse, and produced water recycling facilities.

Oil and gas companies are not required to report the volume of produced water generated in the state. But a 2022 report estimated that in the Permian Basin alone, 3.9 billion barrels, or more than 168 billion gallons, of produced water is generated every year.

While the draft rule imposes stricter requirements than the preexisting rule, it falls short of how other states regulate drilling waste. In North Dakota, for example, open pits for liquid waste—including drilling mud and produced water—are prohibited except under specific circumstances with the regulator's approval. New Mexico updated its waste rules in 2008 and banned unlined pits altogether.

Drilling waste poses groundwater threat

Virginia Palacios saw firsthand the impacts of oilfield waste when the shale boom took off in her hometown of Laredo.

At the Texas Groundwater Summit in San Antonio in August, Palacios, now executive director of Commission Shift, remembered open-top trucks sloshing drilling waste onto the roads in Laredo. She recounted seeing a waste pit at her family's ranch that had an oily sheen even though the company assured them it contained only water.

Most landowners across Texas do not own the minerals under their land. The oil and gas companies that hold these mineral rights enter surface-use agreements with the landowners. These leases can include provisions for waste pits.

“We can’t rely on mineral owners to just get a good lease every time,” Palacios said at the summit. “We’ve got to have good rules that apply across the board everywhere, so that we can ensure that groundwater is safe.”

Palacios is concerned that the draft does not require operators to notify landowners when they dig authorized pits on their land.

“We need to do better by the landowners to let them know what is going to happen and to allow them to give informed consent,” Palacios said.

Pits that are not properly constructed or leach into the soil can contaminate groundwater. According to the commission’s online database, the agency issued 712 violations of water contamination rules since 2015. The commission did not provide clarification about how many of these violations occurred at waste pits. The commission has on record six active cases of groundwater contamination caused by waste pits and one case caused by a commercial waste facility, according to the state’s groundwater protection report.

In addition to nonprofit organizations, some companies have doubts about the rule. Gabriel Rio, CEO of the waste management firm Milestone Environmental Services, told the Midland Reporter-Telegram that the draft rule is not sufficient to protect groundwater. “This very much falls short of what the industry is already doing,” he said.

Milestone Environmental Services declined to comment for this story.

Oil and gas industry provided early recommendations

Jim Wright built on his career in oilfield waste management to win a seat on the Railroad Commission in 2020. Updating the waste rule was one of his priorities as commissioner. His staff formed a regulatory task force to provide recommendations for a revised rule.

The Railroad Commission published the informal draft after receiving this industry feedback.

Commission Shift’s Palacios said she is concerned that the waste management companies subject to the rule had private meetings with regulators before the Railroad Commission shared the informal draft with the public.

Several waste management professionals backed the protective measures during the informal comment period. Landowners and residents also submitted comments in support of the new regulations.

"I don't know how industry can have undue influence on a rule which will undoubtedly be strengthened, especially when the alternative is to do nothing, keep the current rule, and maintain the status quo," Commissioner Wright's spokesperson Aaron Krejci said.

Meanwhile, comments from numerous oil and gas operators pushed back on stricter requirements for reserve pits. The Texas Alliance of Energy Producers sought an exception for liner and groundwater monitoring requirements for reserve pits that are open for less than 18 months before the waste is buried.

Ingham, the Alliance president, said the organization had further meetings with RRC staff and commissioners following the informal comment period. (Palacios confirmed that Commission Shift was also able to meet with agency staff).

Ingham said that these meetings allow industry to provide information that RRC staff may not have at their disposal. "They are willing to take those meetings and listen to us. This is not remotely uncommon," he said.

The latest draft rule includes an option for operators to request exceptions to requirements for reserve pits.

Judy Stark, president of the Panhandle Producers & Royalty Owners Association, said in an interview that a "one size fits all rule" doesn't make sense for her region.

Stark said that notifying landowners of the locations of pits could create costly delays for drillers. "You can't wait if somebody is on vacation or something like that, with a $100,000 a day rig out there," she said.

"They used common sense on the draft," Stark said. "It's still in its draft stage so I can't say where it's going to end up."

Residents feel impacts of waste facilities

Not everyone feels their concerns were heard in the rulemaking process.

Tara Jones lives about a mile from the Blackhorn Environmental Services stationary w... facility in Orange Grove. When odors from the facility permeated Jones' home, she a...

regulators to investigate.

She appealed to the Texas Commission on Environmental Quality, which regulates air emissions from stationary facilities, along with the Railroad Commission and her elected officials. She said stationary waste facilities impact people far beyond their fence lines.

“I am one mile away and there’s only one property owner between us,” she said. “But when it comes to stuff in the air, it doesn’t really matter.”

Jones is skeptical that the Railroad Commission takes public comments into consideration.

“I feel if you kick and scream loud enough, sometimes they do,” she said. “But will it change their mind? I don’t know. I don’t really think so.”

In response to a question about how the Railroad Commission engages landowners and people who live near stationary waste facilities, the agency spokesperson said only that they use “various sources of information and expertise,” including public comments.

“As with any proposed rule, staff will review and incorporate comments,” Ramon said.

Palacios said that the Railroad Commission should hold public hearings near waste facilities, not only in Austin. She pointed out that Reeves County in the Permian Basin, which has the most commercial waste pits in the state, is a seven-hour drive from Austin.

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Exhibit 30.03

This exhibit was not previously submitted in November 2023

May 2023
SFR-56/22

Joint Groundwater Monitoring and Contamination Report

Prepared by the Texas Groundwater Protection Committee

Contributing Agencies and Organizations

Texas Commission on Environmental Quality
Texas Water Development Board
Railroad Commission of Texas
Texas Department of State Health Services
Texas Department of Agriculture
Texas State Soil and Water Conservation Board
Texas Alliance of Groundwater Districts
Texas A&M AgriLife Research
Bureau of Economic Geology of The University of Texas at Austin
Texas Department of Licensing and Regulation

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Joint Groundwater Monitoring and Contamination Report – 2022

Prepared by
Texas Groundwater Protection Committee

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Texas Groundwater Protection Committee

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Committee Membership

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Texas Department of Agriculture
Texas State Soil and Water Conservation Board
Texas Alliance of Groundwater Districts
Texas A&M AgriLife Research
Bureau of Economic Geology of The University of Texas at Austin
Texas Department of Licensing and Regulation

The *Joint Groundwater Monitoring and Contamination Report* was designed and produced by the Texas Groundwater Protection Committee in fulfillment of requirements given in Section 26.406 of the Texas Water Code. The effort was partially funded by the U.S. Environmental Protection Agency. While the information contained in the report includes contributions from all the participating agencies and groups, the report as a whole is the work of the committee and does not necessarily reflect all of the views and policies of every participating organization.

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Railroad Commission of Texas

Oil and Gas Division

Class II Underground Injection Control Program Description

RRC regulates the disposal by injection of oil and gas wastes generated from activities associated with the exploration, development, and production of oil or gas or geothermal resources (Statewide Rule 9), as well as the injection of fluid for enhanced oil recovery (Statewide Rule 46) and the underground storage of hydrocarbons (Statewide Rules 95, 96, and 97). As of December 31, 2022, the inventory of active wells in these categories was 28,541 out of 52,877 currently permitted wells. RRC administers the UIC Program for these Class II wells under authority provided by U.S. EPA under the federal Safe Drinking Water Act (SDWA). The main purpose of the UIC program is to protect underground sources of drinking water. Class II wells must meet permitting standards and be tested and monitored to demonstrate mechanical integrity.

Class III Brine Mining Injection Well Program Description

Brine mining injection wells (Class III) are typical of solution mining wells. The RRC Class III Brine Mining Injection Well Program was approved on March 29, 2004. Since then, all active brine-mining facilities were re-permitted per the provisions of Statewide Rule 81. As of December 31, 2022, there are 213 currently permitted brine mining injection wells in Texas. Most brine mining facilities are required to monitor groundwater quality and submit groundwater-monitoring reports from approximately 218 total monitoring wells. Groundwater monitoring is not conducted at facilities where usable quality groundwater is not present, typically located on salt domes along the Gulf Coast.

Statewide Rule 8 Water Protection, Statewide Rule 57 Reclamation Activities, Chapter 4, Subchapter B Commercial Recycling Program Description

Under 16 TAC Part 1, Chapter 3.8 (Statewide Rule 8, Water Protection), Chapter 3.57 (Statewide Rule 57, Reclamation Activities) and Chapter 4, Subchapter B (Recycling Programs), RRC regulates the acceptance, handling, treatment, storage, reclamation, recycling, and disposal at or near ground surface of oil and gas wastes. The waste streams are generated from activities associated with the exploration, development, and production of oil, gas, or geothermal resources. Statewide Rule (SWR) 8 prohibits the waste of hydrocarbon resources and the pollution of surface and subsurface waters of the state, and requires permits for various pits, waste haulers, and other waste management practices, such as landfarming and land treatment, that are not specifically authorized by rule. SWR 57 specifies the permitting and reporting requirements for the reclamation of hydrocarbons from tank bottoms and other hydrocarbon wastes. 16 TAC Chapter 4, Subchapter B specifies permit requirements and provides guidance for the recycling of generated fluids and solids into a recycled product(s) that has a legitimate commercial reuse.

Currently 306 commercial facilities are permitted to handle, store, treat, or recycle oil and gas waste. There are 63 reclamation plants that are permitted to reclaim hydrocarbons from tank bottoms and other hydrocarbon wastes. Approximately 3,709 pits are permitted to store, handle, or dispose of oil and gas waste. Of the 3,709 pit permits, 1,304 pits (35 percent) are authorized for use as short-term storage (48-72 hours) of produced water during emergency situations. The remaining permits are for various other categories of pits, including disposal pits, collecting pits, washout pits, skimming pits, brine pits, brine mining pits, and gas plant evaporation or retention pits.

S12 permits were issued for the commercial recycling of solid oil and gas waste and 15 permits for commercial recycling of fluid oil and gas wastes. SWR 8, SWR 57, and Chapter 4, Subchapter B permits may include specifications for liner systems, leak detection systems, secondary containment, stormwater management, and groundwater monitoring requirements. RRC responds to complaints regarding alleged groundwater or soil contamination or alleged unauthorized activities that may endanger vadose zone soils, surface water or groundwater. Commission responses may include inspection by the local district office, referral to enforcement and possible penalty action as appropriate.

Oil Field Cleanup Program Description

Oil-field cleanup activities fall under the jurisdiction of RRC and are subject to regulations under SWR 8, SWR 20, SWR 91, and RRC Special Orders. Other rules that protect groundwater and influence cleanup activities include: SWR 13 (well completion requirements), SWR 14 (plugging requirements), SWR 9 (injection [disposal] into a non-productive zone), SWR 46 (injection into a productive zone), SWR 57 (reclamation plants), SWR 93 (water quality certification), SWR 98 (standards for management of hazardous oil and gas waste), and 16 TAC 4.601-4.632[50] (disposal of oil and gas NORM waste). Through SWR 30 (Memorandum of Understanding), RRC maintains jurisdiction over natural gas plants and compressor stations.

If groundwater contamination occurs at a site, the responsible party is required to remediate to acceptable levels. Responsible parties may volunteer remedial action, or cleanup may be required by legal action (Operator Cleanup Program). Operators, developers, or individuals who are not responsible for the contamination may participate in the Voluntary Cleanup Program (VCP). When investigation and research cannot locate a responsible party, the Site Remediation Section of the Oil and Gas Division will oversee the remediation of the groundwater contamination with Oil and Gas Regulatory and Cleanup (OGRC) funds (State Funded Cleanup Program).

Monitoring wells are associated with all cases involving groundwater contamination. The number of monitoring wells at a site depends on the severity of the impact, the expanse of the plume, the toxicity of the contaminants of concern, and the sensitivity of the site. Most of the confirmed groundwater cases listed in this report under RRC

[50] https://texreg.sos.state.tx.us/public/readtac$ext.ViewTAC?tac_view=5&ti=16&pt=1&ch=4&sch=F&rl=Y

jurisdiction are under the purview of the Site Remediation Section of the Oil and Gas Division. There are 453 Operator Cleanup Program (OCP) sites, 36 VCP sites, five sites that are dually enrolled in OCP and VCP, four Brownfields Response Program (BRP) sites, and 47 State Funded Cleanup Program (CU) sites in the Joint Report. Complaints, District Office-managed sites, and sites managed by other sections of the Oil and Gas Division of RRC comprise the remaining listings on RRC portion of the report (15 in number).

Status of Groundwater Contamination. This report includes 560 groundwater contamination cases located in 118 counties. Of these, five are new cases added under RRC regulations. Cases were due to self-reporting, routine investigation, review of data, complaints, violation letters, and legal enforcement action. Two sites were transferred from OCP to CU, activities were completed on six cases listed in the report, and six cases were removed from the previous report.

Surface Mining and Reclamation Division

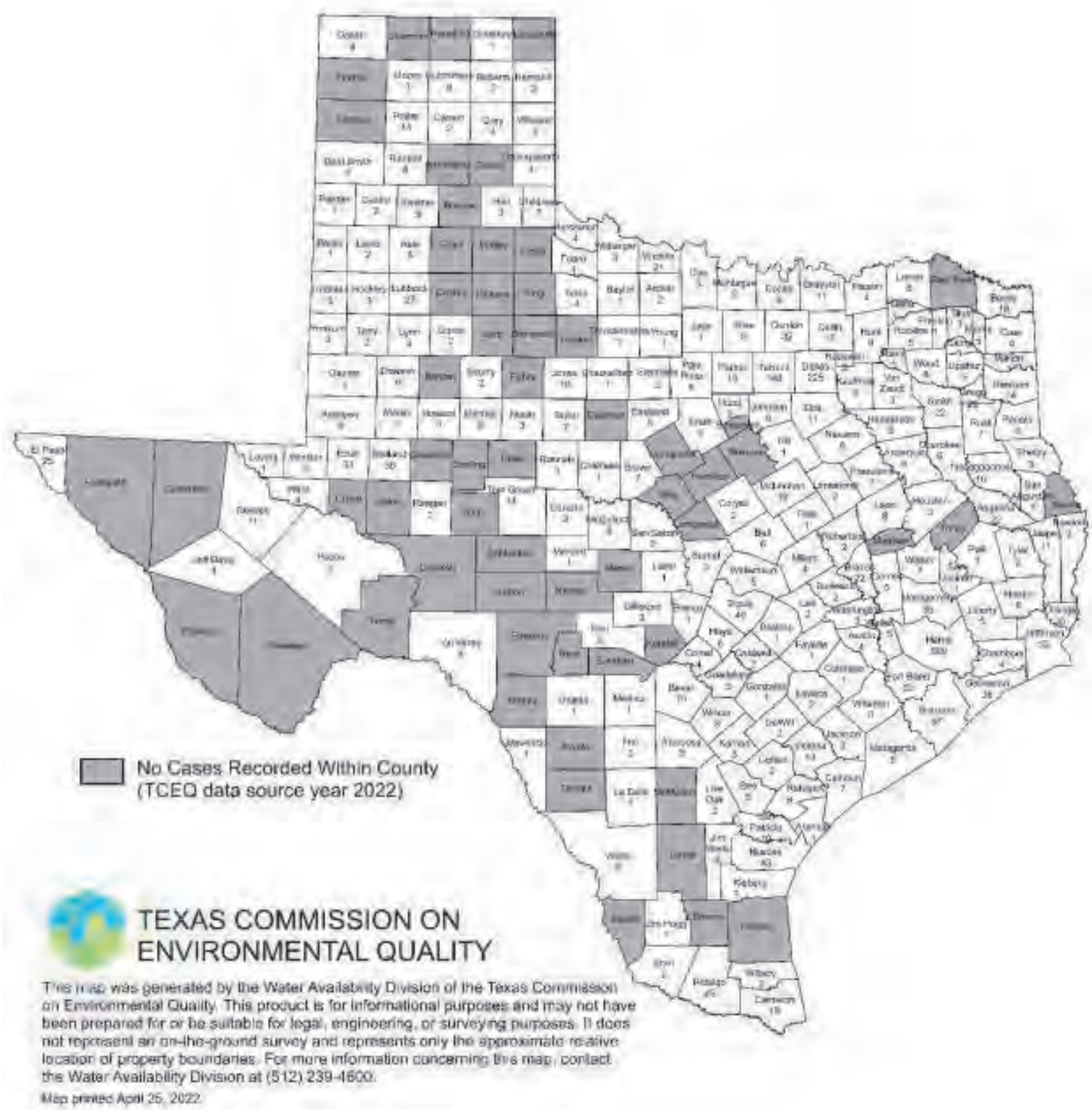
The Surface Mining and Reclamation Division (SMRD) of RRC is authorized to enforce state laws and regulations consistent with the Texas Surface Coal Mining and Reclamation Act, Texas Natural Resources Code (TNRC), Chapter 134 (TSCMRA) and the Texas Uranium Surface Mining and Reclamation Act, TNRC 131 (TUSMRA). As part of the groundwater information required in the regulations, determination of the quality of subsurface water includes the analysis of common inorganic groundwater constituents plus certain trace metals. Monitoring plans for pre-mining, mining, and post-mining conditions are required, normally on a three-month basis, to track variations in water-quality parameters.

For 2022, there are 26 coal mine permits in the Texas. Five different companies at nine permitted sites are currently active, but one has not yet mined coal. Seven companies at 17 permitted sites have mines that are under reclamation operations and one company has two permitted sites where mining activities have not commenced. One company has a permitted site consolidated with its previously permitted facilities area to support a nearby active surface coal mining and reclamation project. Three different companies are conducting uranium exploration activities at nine permitted sites.

Groundwater monitoring, both sampling for water-quality analysis and measurement of water levels, is required for one year on a quarterly basis for the baseline information that is submitted with the initial coal mining permit application. There is no monitoring requirement for uranium exploration permits. The coal mining companies are also required to submit plans for quarterly groundwater monitoring during mining and post-mining reclamation activities for RRC review and approval. Monitoring is performed by or on behalf of the mining companies, which are required to submit the analytical results to RRC on a quarterly basis, usually for the following parameters, in milligrams per liter (mg/L): calcium, magnesium, sodium, potassium, iron (total and dissolved), manganese (total and dissolved), total dissolved solids (TDS), carbonate, bicarbonate, sulfate, chloride, fluoride, and nitrate, as nitrogen.

Typically, an annual sample is also analyzed in a subset of these wells (spoils wells) for the following trace metals, in milligrams per liter: aluminum, arsenic, barium, boron, cadmium, chromium, copper, lead, mercury, molybdenum, selenium, and zinc.

Figure 4. Number of Contamination Sites by County – TCEQ



RRC Active Case Summary, 2022

The list of all confirmed groundwater contamination cases for RRC for calendar year 2022 is provided in Appendix B and will also be posted on the TCEQ Joint Report webpage.[53] This list of cases is provided as part of the Joint *Report* in accordance with Texas Water Code.

Any person interested in reviewing this list may also contact TCEQ's Groundwater Planning and Assessment Team at (512) 239-4600 or by email at gpat@tceq.texas.gov.

Active RRC groundwater contamination cases in Texas that are documented in the current issue (and some previous issues) of the Joint Report are also provided on the TCEQ Groundwater Contamination Viewer.

RRC Active Case Table Key and Explanation of Columns

The following list provides an explanation of column headings, abbreviations, and other data for Appendix C – RRC Active Case List 2022:

- **COUNTY** – the Texas county where the case is located.
- **DIVISION** – the specific regulatory program within RRC responsible for the case.
- **DISTRICT** – the RRC district office where the case is located.
- **NEW** – an asterisk (*) indicates that the record (case) was reported as "New" for the current report year.
- **FILE NAME** – the name provided by the RRC program area, which typically refers to the responsibly party or geographic location. File name may consist of a company name, city, person, or other entity considered a potentially responsible party or otherwise associated with the case, or it may be a geographic location name or well number.
- **FILE NUMBER** – a unique identification number for the case assigned according to RRC district complaint numbering systems. Some districts include the year in the complaint number, and some cases have no numbers if the case was initiated by inspection or some other manner. A few cases are coded according to a RRC hearing docket number. The first two or three letters represents the RRC program: BRP – brownfield response program; OCP – operator cleanup program; VCP – voluntary cleanup program; CU– state funded cleanup program.

[53] https://www.tceq.texas.gov/groundwater/groundwater-planning-assessment/sfr-056-joint-groundwater-monitoring-contamination-report#current

- **LOCATION** – descriptions vary depending on the scope of the investigation and whether a complainant's property is on an oil and gas lease.

- **LATITUDE, LONGITUDE** – geographic coordinates describing the site location, provided in decimal degrees.

- **CONTAMINATION DESCRIPTION** – a specific contaminant or list of contaminants, or a general group of contaminants. The following abbreviations may be present in the table: AS – arsenic; BA – barium; BTEX – benzene, toluene, ethylbenzene, and xylene(s); HG – mercury; NORM – naturally occurring radioactive materials; PB – lead; PSH – phase separated hydrocarbons; SE – selenium; TDS – total dissolved solids.

- *ESC* Refers to enforcement status code. Actions and notices of violations are taken at staff level and may be concurrent. The closure or shut-in of facilities and plugging of wells may also be directed at staff level. Staff directives are identified as enforcement status. Actions may be stepped up to a formal enforcement level which can be categorized as executive action and include administrative penalties and orders. In some cases, groundwater contamination nay be documented but specific source or an actual responsible party cannot be identified. Enforcement status would be categorized as staff discovery. Actions of responsible parties who discover and report groundwater contamination are categorized as voluntary actions even though investigative or remedial plans are reviewed and approved by the oil and gas division. For the meaning of specific codes, refer to Enforcement Status Codes portion of this report.

- ASC Refers to activity status code. Refer to ESC, above. For the meaning of specific codes, refer to Activity Status Codes portion of this report.

- *Data Quality* Data quality refers to the method of sampling utilized to confirm contamination:

  - E – EPA approved analytical procedures

  - Q – quality control program established foe sampling procedures

  - V – verification of contamination through procedures listed below:

    1. Splitting samples with regulated entity or other agency for comparison of analysis results.

    2. Resampling for verification analysis results.

    3. Supervisory or committee review of sampling procedures and analysis results.

Summary Table

Table 9 summarizes the number of active cases for each RRC program in the past calendar year:

Table 9. Summary of RRC Active Cases – 2022

Division / Program	**Number of Cases**	**Percent of RRC Total**	**Percent of Report Total**
O&G/BRP	6	1.1%	0.2%
O&G/OCP	438	78.8%	14.9%
O&G/OCP/VCP and O&G/VCP/VCP	41	7.3%	1.4%
O&G/CU, O&G/OFCU, and O&G/OFCU/OCP	51	9.2%	1.8%
O&G/COMP	15	2.7%	0.5%
O&G/OTH	4	0.7%	0.1%
O&G/PIT	1	0.2%	0.03%
Total Number of RRC Cases:	556	100%	18.9%
Number of **New** RRC **Cases**:	28	5.0%	1.0%
Number of **Counties** with RRC Cases:	116		

RRC Enforcement Status Matrix

The following table shows a matrix chart with the number of contamination cases for RRC that fall within each combination of enforcement status code (ESC) and activity status code (ASC). For additional information on these codes, refer to the Enforcement Status Matrix within the “User’s Guide” of this report.

Table 10. RRC Enforcement Status Matrix – 2022

	ASC 0 – No Action	**ASC 1 – Confirm Contamination**	**ASC 2 – Investigate**	**ASC 3 – Plan Corrective Action**	**ASC 4 – Implement Action**	**ASC 5 – Monitor Action**	**ASC 6 – Action Complete**
ESC 5 – State/ Federal Funds	0	1	12	12	10	21	0
ESC 4 – Court/ Federal Regulatory Action	0	1	0	0	1	1	1
ESC 3 – Executive Action	0	0	3	2	3	1	0

	ASC 0 – No Action	ASC 1 – Confirm Contamination	ASC 2 – Investigate	ASC 3 – Plan Corrective Action	ASC 4 – Implement Action	ASC 5 – Monitor Action	ASC 6 – Action Complete
ESC 2 – Staff Action	0	2	8	5	11	4	1
ESC 1 – Staff Discovery	0	3	10	21	59	28	9
ESC 0 – Voluntary Action	0	7	6	33	141	123	16
Total:	0	14	39	73	225	178	27

RRC Sites Located in Texas Counties

The following map indicates the number of RRC groundwater contamination sites for each county in Texas for 2022. This is subject to change if location information is updated. The most current location information is available on the Excel case list posted on TCEQ's Joint Report webpage.

Appendix B. RRC Active Case List

The list of column headings and abbreviations used in this table is provided in Section V of the report, “TCEQ Active Case Table Key and Explanation of Columns.” In addition, an abbreviated explanation of column headings is provided here:

County The county in Texas where the site is located.

Division The specific regulatory program within RRC responsible for the case.

District The RRC district office where the site is located.

New An asterisk (*) indicates that the case was reported for the first time during the calendar year for this report.

File Name Information provided by the program area, typically meaning the responsibly party or geographic location, and consisting of information such as a company name, location, entity considered a potentially responsible party or otherwise associated with the case, a geographic location name, or a well number.

File Number A number assigned by a program according to its established numbering system.

Location The address or location description of the contamination site.

Latitude and Longitude Geographic coordinates for the site location, in decimal degrees

Contaminants A list of contaminants or general group of contaminants. Abbreviations are included in Section V, RRC Active Case Table Key and Explanation of Columns.

ESC Enforcement status code indicating the level of agency response. For the meaning of specific codes, refer to the enforcement status codes portion of this report.

ASC Activity status code indicating the site activity status. For the meaning of specific codes, refer to the activity status codes portion of this report.

Data Quality refers to the method of sampling utilized to confirm contamination.

Table 12. 2022 RRC Active Groundwater Contamination Cases

COUNTY	DIVISION	DISTRICT	NEW	FILE NAME	FILE NUMBER	LOCATION	LATITUDE	LONGITUDE	CONTAMINANTS	ESC	ASC	DATA QUALITY
ANDREWS	O&G	08		ANDREWS STATION	OCP#2208	EXXONMOBIL PIPELINE CO (EMPCO)	32.2935	-102.5415	TPH, BTEX, PSH	0	4	E,Q,V2
ANDREWS	O&G	08		ANDREWS-TNM-98-13 FORT STOCKTON	OCP#1693	PLAINS MARKETING, L.P. (FORMERLY LINK, EOTT)	32.2964	-102.6425	TPH	0	5	E,Q,V2
ANDREWS	O&G	08		DOLLARHIDE FACILITY	OCP#1048	CHEVRON USA INC. (FORMERLY PURE RESOURCES, PURE ENERGY)	32.14	-103.0511	TPH, CHLORIDE	0	5	E,Q,V2
ANDREWS	O&G	08		FORMER MIDLAND FARMS GAS PLANT	OCP#1021	APACHE CORPORATION (FORMERLY AMOCO)	32.1459	-102.4229	TPH, BTEX	0	5	E,Q,V2
ANDREWS	O&G	08		MIDLAND FARMS DEEP UNIT	OCP#3109	OXY USA (FORMERLY OCCIDENTAL PERMIAN LTD.)	32.1495	-102.4404	TPH, BTEX, PSH, CHLORIDE	0	4	E,Q,V2
ANDREWS	O&G	08		PRIDE PETROLEUM SERVICES	OTH#90007	ANDREWS SOUTH	32.300313	-102.542061	TPH, CHLORIDE	1C	3	E,Q,V2
ANDREWS	O&G	08		SAN ANDRES STATION PERMITTED PITS	OCP#5038	ENTERPRISE PRODUCTS OPERATING LLC	32.1904	-102.4994	CHLORIDE	1B	3	E,Q,V2
ANDREWS	O&G	08		SHAFTER LAKE STATION LINK ENERGY LEAK #2001-10961	OCP#1899	PLAINS PIPELINE L.P. (FORMERLY LINK ENERGY, EOTT ENERGY)	32.3883	-102.6829	TPH, BTEX	0	5	E,Q,V2
ARANSAS	BROWNFIELD	04	*	COMPTON DEVELOPMENT CORPORATION	BRP#4001	5561 HWY 35 NORTH	28.1084	-97.0296	TPH, BENZENE	0	5	E,Q,V2
ARANSAS	O&G	04		ST CHARLES NO. 1 OIL WELL	OCP#5123	HILCORP ENERGY COMPNAY	28.20623	-96.91748	TPH, BTEX	0	4	E,Q,V2
ARANSAS	O&G	04		ST. CHARLES 79/99 FLOWLINE RELEASE	OCP#5131	HILCORP ENERGY COMPANY	28.208847	-96.91496	TPH, BTEX	0	4	E,Q,V2
ARCHER	O&G	09		STEINBERGER TRUCK STATION	OCP#2427	PLAINS MARKETING, L.P.	33.7539	-98.6875	TPH	0	4	E,Q,V2
ATASCOSA	O&G	01		FASHING GAS PLANT	OCP#3000	ETC FIELD SERVICES, LLC (FORMERLY REGENCY GAS SERVICES, BEAR CUB ENERGY) - TRANSFERRED FROM VCP	28.8048	-98.1781	BTEX	1B	4	E,Q,V2
ATASCOSA	O&G	01		JOURDANTON WASHOUT PIT	OFCU#60275	FRAC TANK RENTAL	28.92861	-98.53891	CHLORIDE, AS	5	4	E,Q,V2
AUSTIN	O&G	03		FENNER PROPERTY, NEW ULM	OFCU#70844	MAGNUM PROD. & OPER CO., TEMA OIL & GAS CO., & SAMSON RESOURCES CO. FORMERLY AMERICAN TRADING & PROD. CO. GAS PLANT	29.92933	-96.38175	TPH, CHLORIDE	5	5	E,Q,V2
AUSTIN	O&G	03		RACOON BEND COMMON TANK BATTERY	OCP#3588	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	29.99682	-96.130461	PSH	0	4	E,Q,V2
AUSTIN	O&G	03		WOODLEY SWD SYSTEM-RACOON BEND FIELD	OCP#1294	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	29.99167	-96.12111	BTEX, PSH, BA, CHLORIDE	2	5	E,Q,V2
BASTROP	O&G	01		EAST HOUSTON TO CRANE 18-INCH PIPELINE RELEASE (T4 PERMIT NO 05431)	OCP#5152	MAGELLAN CRUDE OIL PIPELINE COMPANY, LP	30.085883	-97.386189	PSH, BTEX	1B	4	E,Q,V2
BEE	O&G	02		NORMANNA FIELD NATURAL GAS LIQUIDS PLANT	OCP#1804	CHEVRON USA INC. (FORMERLY TEXACO E&P, INC.)	28.532	-97.7755	BTEX	0	4	E,Q,V2
BEE	O&G	02		SMITH PRODUCTION	OCP#1259	ENERGY TRANSFER (FORMERLY HPL/AEP/ENRON)	28.31139	-97.57861	TPH, BTEX	0	4	E,Q,V2
BEE	O&G	02		TULETA GAS PLANT	OCP#1261	HPL/AEP (HOUSTON PIPE LINE CO./ENRON)	28.54538	-97.85775	TPH, NATURAL GAS	1C	4	E,Q,V2
BEE	O&G	02		YOUGEEN DEHYDRATOR SITE	OCP#1944	ENERGY TRANSFER COMPANY (FORMERLY HPLC)	28.34778	-97.77417	TPH, BTEX	0	4	E,Q,V2
BLANCO	O&G	01		PERMIAN HIGHWAY PIPELINE DRILLING FLUID RELEASE	OCP#5226	KINDER MORGAN TEXAS PIPELINE LLC	30.096643	-98.349083	METALS	2	6C	E,Q,V2
BORDEN	O&G	8A		CRMWD COMPLAINT (SOUTH SHORE)	COMP#4832	VINCENT NORTH (LAKE JB THOMAS)	32.57902	-101.20326	CHLORIDE	1C	4	E,Q,V2
BORDEN	O&G	8A		J.B. THOMAS (JBT) LAKE SEEP (VON ROEDER FIELD)	OCP#1130	APACHE CORPORATION	32.60472	-101.205	CHLORIDE	1C	5	E,Q,V2
BORDEN	O&G	8A		JO MILL 8" GATHERING #1	OCP#3320	PLAINS PIPELINE L.P.	32.6367	-101.5082	TPH, BTEX, PSH	0	5	E,Q,V2
BORDEN	O&G	8A		VEALMOOR/RATTLESNAKE NORTH	OCP#1845	PLAINS (FORMERLY LINK ENERGY, EOTT ENERGY)	32.5661	-101.5125	TPH	0	4	E,Q,V2
BRAZORIA	O&G	03		BELCHER, W.T. "B" (10386) LEASE (MANVEL FIELD)	OCP#1635	DENBURY ONSHORE LLC (FORMERLY ARGENT ENERGY HOLDINGS, ENERGYQUEST, POGO PRODUCING, NORTH CENTRAL OIL CORP.)	29.4911	-95.3344	CHLORIDE, OTHER METALS	2	3	E,Q,V2
BRAZORIA	O&G	03		FLESSNER LEASE	OFCU#87604	NASH DOME	29.2467	-95.6531	CHLORIDE	5	5	E,Q,V2
BRAZORIA	O&G	03		MANVEL CRUDE OIL STATION	OCP#5120	GENESIS CRUDE OIL, L.P.	29.501459	-95.344341	TPH, AS	1B	3	E,Q,V2
BRAZORIA	O&G	03		MANVEL SALTWATER DISPOSAL	OFCU#60806	MANVEL FIELD	29.502384	-95.342157	TPH, BA, TDS	5	5	E,Q,V2
BRAZORIA	O&G	03		O.F. EWING LEASE, MANVEL FIELD	OCP#2194	CHEVRONTEXACO	29.50917	-95.33639	TPH, AS, BA, CHLORIDE	2	4	E,Q,V2

COUNTY	DIVISION	DISTRICT	NEW	FILE NAME	FILE NUMBER	LOCATION	LATITUDE	LONGITUDE	CONTAMINANTS	ESC	ASC	DATA QUALITY
BRAZORIA	O&G	03		OLD OCEAN GAS PLANT	OCP#1081	ARROWHEAD PIPELINE (FORMERLY HILCORP)	29.04722	-95.7475	TPH, BTEX, PSH	1D	5	E,Q,V2
BRAZORIA	O&G	03		PEARLAND ASSAULT BASEBALL CLUB	BRP#1301	PEARLAND ASSAULT BASEBALL CLUB	29.516928	-95.348286	CHLORIDE, BA	5	5	E,Q,V2
BRAZORIA	O&G	03		SEAWAY PIPELINE JONES CREEK 12 IN & 20 IN RELIEF LINE SPILL	OCP#4940	ENTERPRISE CRUDE PIPELINE, LLC	28.94034	-95.430744	TPH, BTEX	0	5	E,Q,V2
BRAZORIA	O&G	03		STRATTON RIDGE FACILITY	OCP#1893	DOW CHEMICAL COMPANY	29.034612	-95.360411	CHLORIDE	1A	4	E,Q,V2
BRAZORIA	O&G	03		WEST COLUMBIA ELEMENTARY SCHOOL	OCP#2193	CHEVRONTEXACO	29.13583	-95.64472	TPH, PSH	1B	4	E,Q,V2
BRAZORIA	O&G	03		WEST COLUMBIA FORMER IMPOUNDMENTS SITE (FM 1301 NEAR COUNTY ROAD 943)	OCP#1671	CHEVRON (TEXACO INC.)	29.14667	-95.67278	TPH, PSH, AS, CHLORIDE	1B	4	E,Q,V2
BRAZORIA	O&G	03		WEST COLUMBIA PIT	OCP#4837	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	29.153082	-95.65099	TPH, BTEX, PSH, CHLORIDE	1A	4	E,Q,V2
BRAZORIA	O&G	03		WEST COLUMBIA STATION	OCP#3003	ENTERPRISE PRODUCTS OPERATING, LLC (FORMERLY TEPPCO)	29.14563	-95.675469	TPH, PSH	0	2A	E,Q,V2
BRAZORIA	O&G	03		WEST HASTINGS UNIT LEASE	OCP#3034	TEXCAL ENERGY GP LLC	29.48667	-95.23889	CHLORIDE	0	6C	E,Q,V3
BRAZOS	O&G	03	*	GOEN "B" LEASE (03-14875) PIPELINE RELEASE	OCP #5255	HARVEY SALT WATER DISPOSAL, INC	30.599788	-96.225014	CHLORIDE	1B	5	E,Q,V2
BROOKS	O&G	04		FALFURRIAS/BROOKS CO. (AKA, FALFURRIAS- HWY. 285)	OCP#1487	KOCH PIPELINE CO., LP	27.2275	-98.05667	TPH, BTEX	0	4	E,Q,V2
BROOKS	O&G	04		FORMER SANTA FE RANCH SEPARATION STATION	OCP#3564	SHELL EXPLORATION AND PRODUCTION COMPANY	26.82898	-98.08428	TPH, BTEX, CHLORIDE	1C	4	E,Q,V2
BROOKS	O&G	04		KELSEY COMPRESSOR STATION	OCP#4403	OVERTON PARK OIL & GAS (FORMERLY EXXONMOBIL CORPORATION)	26.8005	-98.4191	TPH, BTEX, PSH, CHLORIDE	0	3	E,Q,V2
BROOKS	O&G	04		KELSEY FIELD CENTRAL TANK BATTERY	OCP#4977	OVERTON PARK OIL & GAS (FORMERLY EXXONMOBIL CORPORATION)	26.8045	-98.4135	TPH, BTEX, OTHER METALS, CHLORIDE	0	4	E,Q,V2
BROOKS	O&G	04		KELSEY FIELD METER STATION 2	OCP#3589	OVERTON PARK OIL & GAS (FORMERLY EXXONMOBIL CORPORATION)	26.8123	-98.4125	TPH, BTEX, CHLORIDE	1C	3	E,Q,V2
BROOKS	O&G	04		KELSEY FIELD STATION B	OCP#4980	OVERTON PARK OIL & GAS (FORMERLY EXXONMOBIL CORPORATION)	26.784644	-98.411712	TPH, BTEX, OTHER METALS, CHLORIDE	0	4	E,Q,V2
BROOKS	O&G	04		KELSEY FORMER TANK BATTERY #7	OCP#4998	OVERTON PARK OIL & GAS (FORMERLY EXXONMOBIL CORPORATION)	26.7859	-98.4027	TPH, BENZENE, CHLORIDE	0	5	E,Q,V2
BROOKS	O&G	04		KELSEY MARSHALL SEPARATION STATION	OCP#4997	OVERTON PARK OIL & GAS (FORMERLY EXXONMOBIL CORPORATION)	26.8366	-98.4028	TPH, BENZENE, PSH, CHLORIDE	0	5	E,Q,V2
BROOKS	O&G	04		KELSEY NORTH METER STATION BLOW DOWN TANK	OCP#3541	OVERTON PARK OIL & GAS (FORMERLY EXXONMOBIL CORPORATION)	26.8211	-98.4011	TPH, BTEX	1C	3	E,Q,V2
BROOKS	O&G	04		KELSEY STATION	OCP#2326	KINDER MORGAN (FORMERLY EL PASO TENESSEE PIPELINE CORPORATION)	26.79639	-98.38417	TPH, BTEX, PSH	0	5	E,Q,V2
BROOKS	O&G	04		KELSEY STATION A 10" PIPELINE	OCP#4999	OVERTON PARK OIL & GAS (FORMERLY EXXONMOBIL CORPORATION)	26.7849	-98.4175	TPH, BENZENE, CHLORIDE	0	5	E,Q,V2
BROOKS	O&G	04		KELSEY TANK BATTERY 4	OCP#3903	OVERTON PARK OIL & GAS (FORMERLY EXXONMOBIL CORPORATION)	26.8235	-98.40783	TPH, BTEX, CHLORIDE	0	3	E,Q,V2
BROOKS	O&G	04		KING RANCH VIBORAS B FACILITY	OCP#4915	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	26.92278	-98.04481	TPH, BTEX, OTHER METALS	0	5	E,Q,V2
BROOKS	O&G	04		KING RANCH VIBORAS COMPRESSOR FACILITY	OCP#3898	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	26.9517	-98.0363	TPH, BTEX	0	5	E,Q,V2
BROOKS	O&G	04		KING RANCH ZACH PASTURE REMOTE	OCP#4917	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	26.9769	-98.0064	TPH, BTEX, OTHER METALS	0	5	E,Q,V2
BROOKS	O&G	04		LOPEZ RANCH	OCP#3601	BOPCO, LP (FORMERLY BASS ENTERPRISES PRODUCTION CO.)	26.88238	-98.18895	PSH, TPH, BTEX, CHLORIDE	0	4	E,Q,V2
BROOKS	O&G	04		MCGILL BROS. NCT-1 LEASE	OCP#4466	CHEVRON U.S.A., INC.	26.835763	-98.381156	TPH, BTEX, CHLORIDE	1C	3	E,Q,V2
BROOKS	O&G	04		SANTA FE RANCH TOM EAST FIELD AOC 1	OCP#5142	TRINITY RIVER ENERGY OPERATING, LLC	26.813005	-98.071875	BTEX, CHLORIDE	0	4	E,Q,V2
BROOKS	O&G	04		SANTA FE RANCH TOM EAST FIELD AOC 2	OCP#5143	TRINITY RIVER ENERGY OPERATING, LLC	26.815163	-98.068187	BTEX, CHLORIDE	0	4	E,Q,V2
BROOKS	O&G	04		SANTA FE RANCH TOM EAST FIELD AOC 3	OCP#5144	TRINITY RIVER ENERGY OPERATING, LLC	26.81858	-98.064054	BTEX, CHLORIDE	0	4	E,Q,V2
BROWN	O&G	7B		PICKETT RANCH	COMP#7312	2 MILES SOUTHEAST OF CROSS CUT	32.0007	-99.0874	CHLORIDE	2	2B	E,Q,V2
CALDWELL	O&G	01		CARTER, ROBERT W. -A-	OCP#4965	B-3 OIL COMPANY	29.72795	-97.621583	CHLORIDE	1C	4	E,Q,V2
CALDWELL	O&G	01		R.W. CARTER PIT, SALT FLAT FIELD	OFCU#60292	CRYSTAL OIL & LAND CO.	29.73086	-97.61074	TPH	5	4	E,Q,V2
CALLAHAN	O&G	7B		BAKER RANCH SEEP	OFCU#60296	UNIDENTIFIED	32.44928	-99.366621	TPH, BTEX, PSH	5	4	E,Q,V2

COUNTY	DIVISION	DISTRICT	NEW	FILE NAME	FILE NUMBER	LOCATION	LATITUDE	LONGITUDE	CONTAMINANTS	ESC	ASC	DATA QUALITY
CARSON	O&G	10		WALT POLING RANCH WATER PANHANDLE WEST	OCP#1627	PHILLIPS PETROLEUM CO.	35.578	-101.622	TPH	0	4	E,Q,V2
CASS	O&G	06		ATLANTA COMPRESSOR STATION	OCP#1035	TEXAS EASTERN PIPELINE CO. (PCB)	33.05187	-94.07132	PCB	0	5	E,Q,V2
CASS	O&G	06		LODI GAS PROCESSING PLANT	OFCU#60742	RODESSA FIELD, 12 MILES S OF ATLANTA, TX	32.90042	-94.14224	TPH, BTEX	5	5	E,Q,V2
CHAMBERS	O&G	03		13.383 ACRES OF VANCANT LAND	VCP#21001	EAST CORNER OF IH10 & HWY61	29.84086944	-94.6402111	TPH	0	2	E,Q,V2
CHAMBERS	O&G	03		BARBERS HILL CRUDE OIL RELEASE	OCP#4177	SUNOCO PIPELINE, L.P.	29.8326	-94.885343	TPH, BTEX	1B	5	E,Q,V2
CHAMBERS	O&G	03		M. B. ENVIRONMENTAL, LLC	VCP#14008	SABINE ENVIRONMENTAL SERVICES, LLC	29.88247	-94.6947	CHLORIDES	0	5	E,Q,V2
CHAMBERS	O&G	03		STERLING, R.S. LEASE	OCP#4985	M.B. ENVIRONMENTAL SERVICES, LLC	29.8666	-94.6833	CHLORIDE, NORM	2	4	E,Q,V2
CHAMBERS	O&G	03		TURTLE BAYOU SITE	BRP#1101	CHAMBERS-LIBERTY COUNTIES NAVIGATION DISTRICT	29.8333	-94.6708	BTEX, CHLORIDE	5	5	E,Q,V2
CHAMBERS	O&G	03	*	WEST STORAGE BRINE POND 1 (PIT PERMIT NO. P005703)	OCP#4935	ENTERPRISE PRODUCTS TEXAS OP LP	29.851013	-94.905974	CHLORIDE	1B	6C	E,Q,V2
CHAMBERS	VCP	03	*	TRACT A RESERVE PARCEL BAY 10 BUSINESS PARK	VCP# 21006	0 HOWARD BAY LANE	29.807228	-94.860928	CHLORIDE	0	1	E,Q,V2
COCHRAN	O&G	8A		LEHMAN COMPRESSOR STATION	OCP#1611	OXY USA INC.	33.5483	-102.8214	TPH	1D	4	E,Q,V2
COKE	O&G	7C		BRONTE CAPPS UNIT SALT WATER RELEASE	OCP#5051	MEMORIAL PRODUCTION OPERATIONS, LLC.	31.8698	-100.3125	TPH, BTEX, PAH, SVOCS, BA, HG, CHLORIDE	0	4	E,Q,V2
COKE	O&G	7C		JAMESON GAS PLANT	OCP#1553	WTG GAS PROCESSING, LP (FORMERLY DEVON GAS SERVICES, LP)	32.0487	-100.6823	TPH	1A	4	E,Q,V2
COKE	O&G	7C		JAMESON WELL COMPLAINT	OCP#3002	SUNOCO, INC.	32.0518	-100.6756	TPH, BTEX	1C	4	E,Q,V2
COKE	O&G	7C		WENDKIRK OIL FIELD	OFCU#60031	NONPOINT SOURCE INVESTIGATION & REMEDIATION	31.8502	-100.3866	CHLORIDE	5	4	E,Q,V2
COLORADO	O&G	3		BOUNDARY VENTURES	OFCU#71203	ALTAIR	29.5495	-96.4583	CHLORIDE, BARIUM , ARSENIC	5	2A	E,Q,V2
COLORADO	O&G	03		FORMER GROUND FLARE PIT, HOUSTON CENTRAL GAS PLANT	OCP#4968	KINDER MORGAN, INC (FORMERLY KINDER MORGAN ENERGY PARTNERS, L.P.)	29.46972	-96.6222	TPH, BTEX, PAH, AS, BA, CHLORIDE	0	4	E,Q,V2
COLORADO	O&G	03		KENNETH OWENS PROPERTY FACILITY	OCP#4936	BOUNDARY VENTURES, INC.	29.550533	-96.458778	CHLORIDE, AS, BA	3	3	E,Q,V2
COLORADO	O&G	03		NEUENDORFF COMPLAINT	OFCU#64622	NORTH OF COLUMBUS	29.842556	-96.521294	CHLORIDE	5	2B	E,Q,V2
COMANCHE	O&G	7B		GOLDEN PEANUT FACILITY, ROUT 2 FM 1496, COMYN, TX	OCP#4816	EXXONMOBIL PIPELINE CO (EMPCO)	32.0696	-98.4646	TPH, BTEX, PSH	1A	4	E,Q,V2
COOKE	O&G	09		TOM DANGLEMYER COMPLAINT	OFCU64790	DANGLE FIELD, 5 MILES SOUTH OF MUENSTER	33.579376	-97.356737	NATURAL GAS	5	3	E,Q,V2
CRANE	O&G	08		BUTLER COMPLAINT	COMP#2793	LEA (SAN ANDRES) FIELD, 10 MILES WEST OF CRANE	31.41641	-102.534656	CHLORIDE	1C	2B	E,Q,V2
CRANE	O&G	08		CRANE STATION	OCP#1989	PLAINS MARKETING, L.P.	31.42434	-102.32729	TPH	0	5	E,Q,V2
CRANE	O&G	08		SANDHILLS COMPRESSOR STATION	OCP#1456	KINDER MORGAN, INC	31.49306	-102.58028	TPH, BTEX, PAH, PSH	0	4	E,Q,V2
CRANE	O&G	08		SANDHILLS GATHERING PIPELINE RELEASE	OCP#5078	PLAINS ALL AMERICAN PIPELINE	31.45363	-102.764214	BTEX	1B	4	E,Q,V2
CRANE	O&G	08		W.A. ESTES #100 WELL	OCP#2423	CHEVRONTEXACO EXPLORATION AND PRODUCTION, INC	31.4545	-102.76228	BTEX, CHLORIDE	2D	3	E,Q,V2
CRANE	O&G	08		WADDELL COMPRESSOR STATION	OCP#1842	KINDER MORGAN, INC	31.52472	-102.44528	TPH, BTEX, PSH	0	5	E,Q,V2
CROCKETT	O&G	7C		PECOS RIVER RELEASE (LIVE OAK TO IRAAN 12" PIPELINE)	OCP#2324	PLAINS PIPELINE L.P.	30.8027	-101.8306	TPH	0	4	E,Q,V2
CROCKETT	O&G	7C		SOUTHWEST OZONA GAS PLANT (7C-0022)	OCP#1210	DUKE ENERGY FIELD SERVICES (FORMERLY UPR)	30.4475	-101.4672	TPH, BTEX	0	4	E,Q,V2
DAWSON	O&G	8A		BREEDLOVE TO MUNGERVILLE #2 SITE, KLONDIKE, TX	OCP#2328	PLAINS ALL AMERICAN	32.56694	-101.93472	TPH, BTEX, PSH	0	4	E,Q,V2
DEWITT	O&G	02		CROZIER TO H SISTERS - 6" GATHERING LINE RUPTURE	OCP#5029	BHP BILLITON	29.112682	-97.581128	PSH	1A	4	E,Q,V2
DEWITT	O&G	02		DEWITT STATION CONDENSATE RELEASE	OCP#5139	KINDER MORGAN, INC.	29.065023	-97.368791	TPH, BTEX	0	4	E,Q,V2
DEWITT	O&G	02		H SISTERS 6" PIPELINE CONDENSATE RELEASE	OCP#5065	BHP BILLITON	29.09	-97.499444	TPH, BTEX, PSH, NATURAL GAS	0	4	E,Q,V2
DEWITT	O&G	02		IMMENHAUSER 6" PIPELINE CONDENSATE RELEASE	OCP#5066	BHP BILLITON	29.165163	-97.440332	PSH, TPH, BTEX	1B	5	E,Q,V2
DEWITT	O&G	02		STEINMANN A1H 8-IN NATURAL GAS PL	OCP#5092	BHP BILLITON	29.251788	-97.300651	TPH, BTEX, PSH	1B	3	E,Q,V2

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DEWITT	O&G	02		TERRYVILLE DEHYDRATOR STATION	OCP#1169	SOUTHCROSS ENERGY (FORMERLY CROSS-TEX ENERGY SERVICES)	29.1625	-97.0611	TPH, BTEX	1A	4	E,Q,V2
DEWITT	O&G	02		ZENGERLE #3 AND #4 BLOWOUT RESPONSE	OCP#3089	APACHE CORP.	28.980321	-97.289235	NATURAL GAS	2	4	E,Q,V2
DIMMIT	O&G	01	*	BAGGETT TRANSFER RELEASE	OCP#5200	TRINITY OPERATING	28.628955	-99.518464	CHLORIDE	1B	6A	E,Q,V2
EASTLAND	O&G	7B		CARSON RANCH OIL SEEP	OCP#2179	CHEVRON ENVIRONMENTAL MANAGEMENT CO. (FORMERLY TEXAS CO.)	32.4994	-98.6539	TPH	2	4	E,Q,V2
ECTOR	O&G	08		EAST GOLDSMITH NATURAL GAS PLANT	OCP#1450	KINDER MORGAN	31.9904	-102.6175	TPH, BTEX, PSH, AMINE	0	4	E,Q,V2
ECTOR	O&G	08		FORMER FOSTER NATURAL GAS PLANT	OCP#2452	AMERICAN CENTRAL GAS TECHNOLOGIES, INC.	31.8624	-102.4294	BTEX, PSH	0	4	E,Q,V2
ECTOR	O&G	08		LYDA MAE JOHNSON LEASE	OCP#5074	MOMENTUM ENERGY CORPORATION (D.B.A. VIEJO ENERGY)	31.828985	-102.402593	TPH, BTEX	1A	4	E,Q,V2
ECTOR	O&G	08		MCKNIGHT SECTIONS 7 & 8, BLOCK 41	OCP#4969	CHEVRON USA INC.	31.90091	-102.32422	BTEX, CHLORIDE	0	4	E,Q,V2
ECTOR	O&G	08		NORTH COWDEN GAS PLANT	OCP#1080	APACHE CORPORATION (FORMERLY BP, AMOCO)	32.0083	-102.51639	BTEX, PSH	0	5	E,Q,V2
ECTOR	O&G	08		ODESSA PUMP STATION	OCP#5132	PHILLIPS 66 COMPANY	31.9514	-102.6048	TPH, BTEX	0	4	E,Q,V2
ECTOR	O&G	08		ROJAS, ELIZABETH WATER WELL COMPLAINT	OCP#5168	CENTURION PIPELINE, L.P.	31.839612	-102.5223	TPH, BTEX, PSH, CHLORIDE	2C	2A	E,Q,V2
ECTOR	O&G	08		SOUTH COWDEN UNIT TRACT 6 BATTERY	OCP#4467	CONOCOPHILLIPS	31.7562833	-102.3746	CHLORIDE	1C	5	E,Q,V2
ECTOR	O&G	08		TXL GAS PLANT	OCP#1656	SHELL WESTERN E & P	31.916693	-102.745729	TPH, BTEX	0	4	E,Q,V2
FAYETTE	O&G	03	*	ELO #3	OCP#5260	SENORA RESOURCES, INC	30.041868	-96.710111	TPH	1B	3	E,Q,V2
FISHER	O&G	7B		PIERCE WATER WELL COMPLAINT	OFCU#103764	UNIDENTIFIED	32.7544917	-100.2634417	PSH	5	3	E,Q,V2
FORT BEND	O&G	03		F.I. BOOTH LEASE (04099) THOMPSON FIELD	OCP#1691	DENBURY ONSHORE, LLC (FORMERLY EXXONMOBIL)	29.467079	-95.571055	BENZENE, CHLORIDE	0	4	E,Q,V2
FORT BEND	O&G	03	*	FORMER MISSOURI CITY PUMP STATION	OCP#5268	PHILLIPS 66	29.616053	-95.501996	BENZENE	1B	3	E,Q,V2
FORT BEND	O&G	03		FORMER WELL NO. 6 SITE	OCP#5081	ATLAS OIL & GAS EXPLORATION, LLC	29.55758	-95.578869	TPH, BTEX, SVOCS	0	2B	E,Q,V2
FORT BEND	O&G	03		HERITAGE COLONY DRIVE SITE	VCP#14003	LING FAMILY LIMITED PARTNERSHIP	29.55758	-95.57886	PSH, CHLORIDE	0	4	E,Q,V2
FORT BEND	O&G	03		LAKE AREA- SUGAR LAND RANCH	VCP#80002	SUGAR LAND RANCH DEVELOPMENT LLC	29.551	-95.5802	TPH, BENZENE, PSH	0	5	E,Q,V2
FORT BEND	O&G	03		ROUEN RD CRUDE OIL RELEASE	OCP#2620	PLAINS MARKETING, L.P.	29.5697	-95.4744	TPH, PSH	0	5	E,Q,V2
FORT BEND	O&G	03		SUGAR LAND RANCH SECTION 6 EAST	VCP#16004	HILLSBORO ESTATES LLC	29.5529167	-95.584767	TPH, CHLORIDE	0	3	E,Q,V2
FORT BEND	O&G	03		SUGAR LAND RANCH SECTION 6 WEST	VCP#16005	HILLSBORO ESTATES LLC	29.557067	-95.588067	TPH, CHLORIDE	0	3	E,Q,V2
FRANKLIN	O&G	06		WINNSBORO STATION	OCP#3590	SHELL PIPELINE COMPANY LP	33.06389	-95.27	TPH, BTEX, PSH	4	6C	E,Q,V2
FREESTONE	O&G	05		INGRAMS TRINITY UNIT, TPWD SITES 1 & 2	OCP#1663	SOUTHWEST OPERATING INC	31.9786	-96.0661	CHLORIDE	2	4	E,Q,V2
FRIO	O&G	01		RECLAMATION PLANT-RIGGS SWD	OFCU60276	1 MILE S PEARSALL	28.8699	-99.1014	TPH	5	4	E,Q,V2
GAINES	O&G	8A		ADAIR SAN ANDRES UNIT, WELL NO. 1208	OCP#4972	APACHE CORPORATION	32.9544	-102.2925	TPH, BTEX, CHLORIDE	0	2A	E,Q,V2
GAINES	O&G	8A		ALVIN REMPL COMPLAINT	OCP#5243	REMPL PROPERTY	32.7363	-102.7075	BENZENE, TPH, SVOC	0	2	E,Q,V2
GAINES	O&G	8A		FLANAGAN CRUDE OIL PIPELINE RELEASE SITE	OCP#2428	EXXONMOBIL PIPELINE CO (EMPCO)	32.5492	-102.7041	TPH, BTEX	0	6C	E,Q,V2
GAINES	O&G	8A		NORTH RILEY UNIT INJECTION WELL #104, #107, #289 BREAKOUT (API 42-165-01027)	OCP#4989	CHEVRON USA INC.	32.6876	-102.8138	CHLORIDE	0	4	E,Q,V2
GAINES	O&G	8A		TOBE JOE PUMP 4-INCH (FORMERLY ANITA)	OCP#4946	PLAINS PIPELINE, LP	32.6579	-102.55754	TPH, BTEX	0	5	E,Q,V2
GAINES	O&G	8A		WARDSWELL DRAW NATURAL GAS DELINEATION PROJECT	OCP#5137	HESS CORPORATION	32.7312	-102.6937	NATURAL GAS	4	5	E,Q,V2
GAINES	O&G	8A		WOOD STATION-SEMINOLE,TX	OCP#1138	APACHE CORPORATION	32.756	-102.7195	TPH, BTEX, PSH	1A	6C	E,Q,V2
GALVESTON	O&G	03		A.J. OUTTERSIDE LEASE PRODUCED WATER RELEASE	OCP#5158	NOXXE OIL AND GAS, LLC	29.470643	-95.011075	BENZENE	1C	3	E,Q,V2
GALVESTON	O&G	03		APPROXIMATE 12.5 ACRE TRACT	VCP#15007	AFFINITY BAYVIEW I, LTD.	29.46461	-95.10526	CHLORIDE	0	4	E,Q,V2
GALVESTON	O&G	03		BAY COLONY PARK	VCP#20005	LEAAGUE CITY PATRONS OF THE PARK FOUNDATION	29.464542	-95.110028	BARIUM, CADMIUM	1B	3	E,Q,V2

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GALVESTON	O&G	03		E.A. DEWITT FEE FORMER PIT AND TANK BATTERY (LEASE NO 05611)	OCP#5164	BP AMERICA PRODUCTION COMPANY	29.490838	-95.225137	TPH, BTEX, CHLORIDES	1B	3	E,Q,V2
GALVESTON	O&G	03		LEAGUE CITY HISTORIC PITS	OCP#4970	CONOCO PHILLIPS	29.470736	-95.110444	TPH, BTEX, OTHER METALS, CHLORIDE	1C	6C	E,Q,V2
GALVESTON	O&G	03		WEST HASTINGS FIELD TRACT 94	OCP#5167	DENBURY ONSHORE, LLC	29.482161	-95.227699	CHLORIDE, BARIUM	0	4	E,Q,V2
GARZA	O&G	8A		DAVID BAEZA COMPLAINT	COMP#151	JUSTICEBURG, TEXAS	33.030745	-101.19857	CHLORIDE	2	2A	E,Q,V2
GILLESPIE	O&G	01		FREDERICKSBURG PUMP STATION	OCP#1694	SHELL OIL PRODUCTS US (FORMERLY TEXAS-NEW MEXICO PIPE LINE)	30.2489	-99.1064	TPH, BTEX	0	4	E,Q,V2
GLASSCOCK	O&G	08		BRUNSON TRENCH RELEASE	OCP#5058	PIONEER NATURAL RESOURCES	31.938725	-101.691069	TPH, BTEX	0	4	E,Q,V2
GLASSCOCK	O&G	08		DRIVER SPRABERRY HISTORIC RELEASE	OCP#5148	PLAINS MARKETING, L.P.	31.9066	-101.7714	TPH, BTEX	0	4	E,Q,V2
GOLIAD	O&G	02		MCCLELLAN WATER WELL COMPLAINT	OFCU#71688	WEST OF BETHKE RD. NEAR OILFIELD RD.	28.4565	-97.5112	CHLORIDE	5	3	E,Q,V2
GRAY	O&G	10		LEFORS 10" CRUDE OIL PIPELINE (F.M.1321)	OCP#2327	PLAINS MARKETING, L.P.	35.42453	-100.72935	TPH, BTEX, PSH	0	4	E,Q,V2
GRAY	O&G	10		LEFORS PLANT (T4 NO. 00109) NEED R3 NO	OCP#4010	ENERGY TRANSFER (FORMERLY REGENCY, EAGLE ROCK FIELD SERVICES)	35.43162	-100.76257	TPH, BTEX, PSH	0	4	E,Q,V2
GRAY	O&G	10		MATT HINTON COMPLAINT	OFCU#61755	UNIDENTIFIED	35.48995	-100.941	BTEX	5	2A	E,Q,V2
GREGG	O&G	06		DOUGLAS FEE SWD	OCP#3899	KEY ENERGY SERVICES, INC.	32.430093	-94.938062	BTEX, VOCS, BA, CHLORIDE	0	4	E,Q,V2
GREGG	O&G	06		EAST TEXAS GAS PLANT/JOHN MCCLENDON WATER WELL	OCP#5041	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	32.4478	-94.8946	BENZENE	1C	1	E,Q,V2
GREGG	O&G	06		FORMER GLADEWATER NATURAL GAS PROCESSING PLANT	OCP#4441	CHEVRON U.S.A. INC.	32.555702	-94.89625	TPH, BTEX, PSH	0	5	E,Q,V2
GREGG	O&G	06		FORMER GREGG-TEX NATURAL GAS PROCESSING PLANT	OCP#4440	CHEVRON U.S.A. INC.	32.576944	-94.825278	TPH, BTEX, PSH, AS	0	5	E,Q,V2
GREGG	O&G	06		FORMER SPEAR GAS PROCESSING PLANT	OCP#3304	CHEVRON U.S.A. INC.	32.37883	-94.88738	CHLORIDE, AS	0	5	E,Q,V2
GREGG	O&G	6		TRIPLE M- PETRO WAX	OFCU#62737/OCP#5265	KILGORE - PETRO WAX	32.3745	-94.8886	SODIUM, CHLORIDE, TPH	5	2B	E,Q,V2
GREGG	O&G	06		WILLOW SPRINGS FACILITY	OCP#1172	XTO ENERGY (FORMERLY CROSS TIMBERS OPERATING CO.)	32.48111	-94.78	BTEX	0	4	E,Q,V2
GREGG	O&G	06		WILLOW SPRINGS GAS DEHYDRATOR PLANT	OCP#4281	GULF SOUTH PIPELINE COMPANY, LP	32.515548	-94.771731	TPH, BTEX	0	5	E,Q,V2
GREGG	O&G	6E		ANDERSON COLLECTION CENTER PIT	OCP#5125	EAST TEXAS SALTWATER DISPOSAL	32.49504	-94.854498	BTEX, CHLORIDE	1C	4	E,Q,V1
HARDEMAN	O&G	09		HARDEMAN GATHERING THRASH PIPELINE	OCP#4971	PLAINS MARKETING, LP	34.3566	-99.5603	TPH, BTEX, PSH	0	5	E,Q,V2
HARDEMAN	O&G	09		HARDEMAN NORTH PIPELINE	OCP#3038	PLAINS ALL AMERICAN	34.3719	-99.57	TPH, BTEX, PSH	0	4	E,Q,V2
HARRIS	O&G	03		11 ACRE FANNIN PROPERTY	VCP#70009	FANNIN 11-A	29.6626	-95.4025	CHLORIDE, AS	0	3	E,Q,V2
HARRIS	O&G	03		412 MOONSHINE HILL RD	OCP#5130	SHELL OIL COMPANY	30.005132	-95.233771	TPH, CHLORIDE, PB, AS, CR	1B	6C	E,Q,V2
HARRIS	O&G	03		BEN PETRICH LEASE (SHERMAN TRACT)	OCP#3049	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	30.07383	-95.66008	TPH, CHLORIDE	0	6C	E,Q,V2
HARRIS	O&G	03		BUFFALO POINTE - C-1	VCP#17008	BOARD OF REGENTS OF THE UNIVERSITY OF TEXAS SYSTEM	29.666028	-95.421167	CHLORIDE	0	5	E,Q,V2
HARRIS	O&G	03		BUFFALO POINTE - TRACT A AND TRACT A-1	VCP#17006	BOARD OF REGENTS OF THE UNIVERSITY OF TEXAS SYSTEM	29.667472	-95.428944	CHLORIDE	0	5	E,Q,V2
HARRIS	O&G	03		BUFFALO POINTE - TRACT C- SOUTH	VCP#17005	BOARD OF REGENTS OF THE UNIVERSITY OF TEXAS SYSTEM	29.663667	-95.425056	CHLORIDE	1	5	E,Q,V2
HARRIS	O&G	03		BUFFALO POINTE - TRACT D	VCP#17007	BOARD OF REGENTS OF THE UNIVERSITY OF TEXAS SYSTEM	29.665861	-95.417972	CHLORIDE	0	5	E,Q,V2
HARRIS	O&G	03		BUFFALO POINTE TRACT B	VCP#17002	THE UNIVERSITY OF TEXAS SYSTEM BOARD OF REGENTS	29.66206	-95.427693	TPH, AS, BA, PB, SE, CHLORIDE	0	5	E,Q,V2
HARRIS	O&G	03		EHRHARDT TANK BATTERY	OCP#4399	BRAMMER ENGINEERING, CATHEXIS, (FORMERLY EOG RESOURCES, INC)	29.989981	-95.454034	TPH, BTEX	0	5	E,Q,V2
HARRIS	O&G	03		FORMER STEVE SIMON COMPLAINT, 97 ISAACKS RD SITE	OCP#2538	CHEVRON	29.99306	-95.25833	CHLORIDE	1C	4	E,Q,V2
HARRIS	O&G	03		FORMER SUN HUMBLE PITS SITE (HUMBLE, TX) (RRC ORDER SITE)	OCP#1064	SUNOCO INC.	29.96306	-95.25694	TPH, PSH	3	4	E,Q,V2

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HARRIS	O&G	03		GOOSE CREEK	OFCU#63587	SIMMS-SWEET LEASE, BAYTOWN CITY LIMITS	29.7128	-94.9812	TPH, PSH	5	5	E,Q,V2
HARRIS	O&G	03		HULDA MARTENS LEASE	OCP#1063	TORTUGA OPERATING CO.	30.08288	-95.649408	CHLORIDE	2	3	E,Q,V2
HARRIS	O&G	03		JLC 11755 W LITTLE YORK RD LLC	VCP#18001	JLC 11755 W LITTLE YORK RD LLC	29.865525	-95.584969	BA, CHLORIDE	0	4	E,Q,V2
HARRIS	O&G	03		KINGS RIVER DEVELOPMENT SITE	OCP#1069	FRIENDSWOOD LAND DEVELOPMENT	30.011841	-95.171002	TPH, BENZENE	1C	5	E,Q,V2
HARRIS	O&G	03		KMIEC TRACT EAST 25.25 ACRES TR 2D; ABST 372 J M HOOPER	OCP#4277	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	30.0726	-95.6546	CHLORIDE	0	4	E,Q,V2
HARRIS	O&G	03		KMIEC TRACT WEST TR 2; 25.20 ACRES, ABST 372 J M HOOPER	OCP#4278	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	30.0726	-95.6527	CHLORIDE	0	4	E,Q,V2
HARRIS	O&G	03		MEMORIAL GLEN SUBDIVISION (RRC ORDER SITE)	OCP#1680	CHEVRONTEXACO, INC.	29.98389	-95.25528	TPH, BA, CHLORIDE	1B	4	E,Q,V2
HARRIS	O&G	03		MILAGRO DEHYDRATOR STATION	VCP#16002	MISCHER INVESTMENTS, INC	29.926204	-95.717681	TPH, BTEX	0	5	E,Q,V2
HARRIS	O&G	03		MULTIPLE DESCENDANTS OF E.R. TAYLOR	BRP#5003	MULTIPLE DESCENDANTS OF E.R. TAYLOR	29.6446	-95.4023	TPH, BTEX, CHLORIDE	5	5	E,Q,V2
HARRIS	O&G	03		OTH-13 PIPELINE CRUDE OIL RELEASE, T4-08571	OCP#5171/VCP #19001	ENTERPRISE HOUSTON SHIP CHANNEL, LP	29.706966	-95.238295	TPH, BTEX	1B	4	E,Q,V2
HARRIS	O&G	03		PETRICH TRACT, 27.5 ACRE TELGE RD. TOMBALL TEXAS	OCP#4275	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	30.07266	-95.6602	CHLORIDE	0	4	E,Q,V2
HARRIS	O&G	03	*	PROPOSED STARBUCKS RETAIL SITE	VCP#21010	1653 THOMBALL PARWAY	29.911414	-95.481489	ARSENIC, LEAD	0	6C	E,Q,V2
HARRIS	O&G	03	*	RESERVE PIT G	OCP#5285	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	29.619473	-95.102809	CHLORIDE	1B	3	E,Q,V2
HARRIS	O&G	03		RIVERSTAR PARTNERS, LLC	VCP#13003	GRANT MEADOWS SECTION 3 - NORTH ENTRANCE	30.0226	-95.65019	TPH, BENZENE, TOULENE	1B	2B	E,Q,V2
HARRIS	O&G	03		SCHMIDL-BROOKS #1, CROSBY BLOWOUT CRATER	OCP#2433	LOUISIANA GAS DEVELOPMENT CORPORATION	29.8869	-95.0152	BTEX, NATURAL GAS	2	4	E,Q,V2
HARRIS	O&G	03		SCHNEIDER TRACT, TELGE ROAD	OCP#4402	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	30.070421	-95.659123	CHLORIDE, BA	0	4	E,Q,V2
HARRIS	O&G	03		SHAW STREET CRUDE OIL RELEASE (W COLUMBIA 16" TRANSMISSION PIPELINE)	OCP#4953/VCP #14004	SHELL PIPELINE COMPANY LP	29.71611	-95.221958	TPH, BTEX, PSH	0	4	E,Q,V2
HARRIS	O&G	03		SNYDER LEASE TRACT- 27.5 ACRES, TELGE RD. TEXAS	OCP#4276	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	30.07156	-95.65931	CHLORIDE	0	4	E,Q,V2
HARRIS	O&G	03		THOMPSON, E.P.	OFCU#60145	HUMBLE FIELD, HIGGINS LEASE	29.9932	-95.241	CHLORIDE	5	5	E,Q,V2
HARRIS	O&G	03		WHITE DEER LANE	OCP#2174	CHEVRON (FORMERLY TEXACO E&P, INC)	30.01917	-95.2225	TPH, BTEX, PSH	0	4	E,Q,V2
HARRIS	O&G	03	*	WILSON ROAD CHEVERON-OWNED PROPERTIES	OCP #5286	CHEVRON ENVIRONMENTAL MANAGEMENT COMPANY	29.97333	-95.25083	TPH, BA, CHLORIDE	1B	4	E,Q,V2
HARRIS	O&G	03		WILSON ROAD SITE (RRC ORDER SITE)	OCP#1685	CHEVRONTEXACO, INC.	29.97333	-95.25083	TPH, PSH	3	4	E,Q,V2
HARRIS	VCP	03	*	29.9 ACRES, CLEAR LAKE	VCP# 21012	N/A	29.609108	-95.107452	BARIUM, CHLORIDE	0	5	E,Q,V2
HARRIS	VCP	03	*	BUSINESS PARK	VCP# 22007	1325 S HOUSTON AVE	29.982667	-95.2589902	AS, BA, SE, TPH, SEC-BUTYLBENZE, ISOPROPYLBENZENE, MTBE, N-PROPYLBENZENE	0	1	E,Q,V2
HARRIS	VCP	03	*	HARDY PROPERTIES	VCP# 22003	15701-15731 WEST HARDY ROAD	29.945777778	-95.385722222	TPH, BARIUM	0	3	E,Q,V2
HARRIS	VCP	03	*	RED BLUFF ROAD	VCP# 21011	RED BLUFF ROAD AND GENOA RED BLUFF ROAD	29.63628	-95.115016	BARIUM, CHLORIDE	0	6C	E,Q,V2
HARRIS	VCP	03	*	SANS SOUCI BALLROOM	VCP# 21008	26511 TX 249	30.0611	-95.6219	ARSENIC, CHROMIUM, LEAD	1D	4	E,Q,V2
HARRIS	VCP	03	*	STORWAY-A-WAY STORAGE FACTILITY	VCP# 19010	2155 FM 1960 F	29.999732	-95.242116	CHROMIUM, CHLORIDE	0	5	E,Q,V2
HARRIS	VCP	03	*	UNIVERSAL EQUIPMENT TRUCKING YARD	VCP# 21005	9987 WALLISVILLE ROAD	29.791267	-95.252942	BARIUM, CHLORIDE	0	5	E,Q,V2
HARRISON	O&G	06		EXCO RUDD NO. 33 AND J.M. BRYSON SALTWATER FACILITY	OCP#4686	EXCO RESOURCES, INC.	32.46015	-94.059261	BENZENE, CHLORIDE	0	5	E,Q,V2
HARRISON	O&G	06		MILLER WATER WELL COMPLAINT	OFCU#75403	LONGWOOD FIELD	32.5314	-94.0467	CHLORIDE, PH	5	3	E,Q,V2
HARRISON	O&G	06		RAY H. EUBANKS #1 SWD FACILITY	OCP#1171	XTO ENERGY (FORMERLY CROSS TIMBERS OPERATING CO.)	32.56194	-94.66861	BTEX	0	4	E,Q,V2
HARRISON	O&G	06		WASKOM WASTE SEPARATION (STF) FACILITY	OCP#5237	MCBRIDE OPERATING, LLC	32.490833	-94.136667	BENZENE, TPH, CHLORIDE	4A	1	E,Q,V2

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HEMPHILL	O&G	10		LORA COMPRESSOR STATION (T4 04193)	OCP#2439	ENERGY TRANSFER (FORMERLY REGENCY, EAGLE ROCK FIELD SERVICES)	35.7362	-100.45142	TPH, BTEX, PSH	0	4	E,Q,V2
HEMPHILL	O&G	10		MCMORDIE WELL 308H LEASE, NO. 262388, ALLISON PARKS FIELD	OCP#5182	TECOLOTE ENERGY OPERATING, LLC	35.668006	-100.127094	CHLORIDE	1	4	E,Q,V2
HEMPHILL	O&G	10		WILLIAMS HOBART RANCH GAS PLANT	OCP#2211	WILLIAMS ENERGY SERVICES (FORMERLY ENBRIDGE PIPELINES - TEXAS GATHERING)	35.74799	-100.3979	BTEX	0	5	E,Q,V2
HENDERSON	O&G	6		KOEPP	OFCU60329	2 MILES SW OF CROSS ROADS TX	32.0164	-95.9898	CHLORIDE	5	2B	E,Q,V2
HIDALGO	O&G	04		A.E. GUERRA 104 FLOWLINE RELEASE	OCP#5165	HILCORP ENERGY COMPANY	26.57404	-98.23136	BTEX	0	5	E,Q,V2
HIDALGO	O&G	04		EAST MCCOOK CENTRAL FACILITY, PIT PERMIT	OCP#5026	SHELL EXPLORATION AND PRODUCTION CO.	26.468892	-98.381008	TPH, BTEX	0	3	E,Q,V2
HIDALGO	O&G	04		GANAWAY FACILITY	OCP#5008	MO-VAC SERVICE CO., INC.	26.38394	-98.29732	CHLORIDE	2	2A	E,Q,V2
HIDALGO	O&G	04		HAMMAN COMPRESSOR STATION	OCP#5045	HILCORP ENERGY COMPANY (FORMERLY NEWFIELD EXPLORATION COMPANY)	26.44682	-98.28924	TPH, BTEX, PSH	0	4	E,Q,V2
HIDALGO	O&G	04		MCALLEN RANCH	OCP#2613	HILCORP (FORMERLY FOREST OIL PRODUCTION)	26.60222	-98.26583	BENZENE, OTHER METALS	0	5	E,Q,V2
HIDALGO	O&G	04		MONTE CHRISTO FI JOHNSON	OCP#4286	HILCORP ENERGY COMPANY (FORMERLY NEWFIELD EXPLORATION COMPANY, EXXONMOBIL)	26.463	-98.319	TPH, BENZENE, PSH, CHLORIDE	0	4	E,Q,V2
HIDALGO	O&G	04		SHELL MCALLEN STATION (FORMER COASTAL STATES CRUDE GATHERING CO)	OCP#1837	KINDERMORGAN (FORMERLY EL PASO MERCHANT ENERGY-PETROLEUM CORP)	26.62167	-98.3169	TPH, BTEX, PSH	0	4	E,Q,V2
HIDALGO	O&G	04		SHOEMAKE, E.C., ET AL	OFCU#107043	WHITESANDS OPERATING, LLC	26.187738	-98.186536	PSH, MTBE, BTEX, TPH	5	2A	E,Q,V2
HOCKLEY	O&G	8A		BILLY CARTER COMPLAINT	COMP#4875	SUNDOWN NORTHWEST	33.40629	-102.44553	CHLORIDE	1C	1B	E,Q,V2
HOCKLEY	O&G	8A		ELLWOOD "A" LEASE (06169), WELL NO. 50W	OCP#5189	APACHE CORPORATION	33.639811	-102.172689	BTEX, CHLORIDE, TDS, LI, RA, SR, V	1C	5	E,Q,V2
HOCKLEY	O&G	8A		FARRIS SWD WELL FAILURE	OCP#4988	CHEVRON USA INC.	33.4403	-102.5238	TPH, BENZENE, CHLORIDE	0	4	E,Q,V2
HOCKLEY	O&G	8A		LEVELLAND GAS PLANT	OCP#1120	OXY PERMIAN LTD. (FORMERLY AMOCO PRODUCTION CO.)	33.5938	-102.4321	BTEX, CHLORIDE	0	5	E,Q,V2
HOCKLEY	O&G	8A	*	MALLET CO2 RECOVERY PLANT	OCP #5287	OCCIDENTAL PERMIAN LTD	33.459962	-102.56047	BENZENE	0	1	E,Q,V2
HOCKLEY	O&G	8A		MALLET RANCH PIPELINE RELEASE	OCP#1556	CONOCOPHILLIPS (FORMERLY EXXONMOBIL, MOBIL E & P)	33.46806	-102.5944	TPH	0	3	E,Q,V2
HOCKLEY	O&G	8A		RATLIFF SITE	OCP#5118	CHEVRON USA INC.	33.4237	-102.4731	CHLORIDE	0	6C	E,Q,V2
HOCKLEY	O&G	8A		RATLIFF SITE, NON-SABINAL OWNED PROPERTY	OCP#5202	SABINAL ENERGY OPERATING, LLC, FORMERLY CHEVRON USA INC.	33.4097	-102.4606	CHLORIDE	0	5	E,Q,V2
HOCKLEY	O&G	8A		SLAUGHTER GAS PLANT	OCP#1121	OXY PERMIAN LTD. (FORMERLY AMOCO PRODUCTION CO.)	33.4697	-102.5592	TPH, BTEX	0	5	E,Q,V2
HOOD	O&G	7B		MANNING COMPLAINT	OCP#5150	EAGLERIDGE OPERATING, LLC	32.5195	-97.8485	TPH, BTEX, PSH, CHLORIDES	1C	4	E,Q,V2
HOOD	O&G	7B		TOLAR PLANT	OCP#3067	DCP MIDSTREAM, LLC	32.3433	-97.8883	BENZENE	0	4	E,Q,V2
HOUSTON	O&G	06		EVAPORATION PIT, NAVARRO CROSSING FEE PROPERTY NOS. 95892/107580	OCP#4458	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	31.435408	-95.70905	CHLORIDE	0	4	E,Q,V2
HOUSTON	O&G	06		FORMER NAVARRO CROSSING SALTWATER STATION	OCP#3598	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	31.439696	-95.693506	BENZENE, PSH, AS	0	6C	E,Q,V2
HOWARD	O&G	08		ANDERSON SEEP	OFCU#64747	VEALMOOR FIELD	32.5121	-101.5856	BENZENE, CHLORIDE	5	3	E,Q,V2
HOWARD	O&G	08		HAMBY COMPLAINT	COMP#3015	6 MILES SOUTH OF I-20 ON SNYDER FIELD ROAD	32.22636	-101.23865	CHLORIDE	1C	2B	E,Q,V3
HOWARD	O&G	08		HODNETT COMPLAINT (SFCU SITE)	OFCU#64754	2 MILES N OF VINCENT	32.49768	-101.2235	TPH	5	5	E,Q,V2
HOWARD	O&G	08		MCGREGOR ROAD SITE (COAHOMA AREA)	OCP#1412	FINA PIPELINE (COSDEN)	32.29889	-101.2828	TPH	0	5	E,Q,V2
HOWARD	O&G	08		O'DANIEL SEEP DRAINAGE ABATEMENT TRENCH	OCP#3095	MERIT ENERGY CO.	32.2303	-101.2316	CHLORIDE	1C	4	E,Q,V2
HOWARD	O&G	08		O'DANIEL SEEP RECOVERY SYSTEM	OCP#3094	LINN OPERATING, INC.	32.23277	-101.242107	BENZENE	1A	4	E,Q,V2
HOWARD	O&G	08		O'RYAN SEEP	OFCU#64753	EAST HOWARD (IATAN) FIELD	32.2817	-101.2528	CHLORIDE	5	3	E,Q,V2
HOWARD	O&G	08		PHARAOH SEEP	CU#64752	EAST HOWARD (IATAN) FIELD	32.2742	-101.2464	BENZENE, CHLORIDE	5	3	E,Q,V2
HOWARD	O&G	08		RANKIN SEEP	OCP#1880	MERIT ENERGY COMPANY (FORMERLY ANADARKO PETROLEUM CORP.)	32.2283	-101.2147	TPH, BENZENE, CHLORIDE	1A	5	E,Q,V2

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HOWARD	O&G	08		SNYDER FIELD SEEPS (SAHARA OPERATING CO.)	OCP#4174	SAHARA OPERATING COMPANY	32.2355	-101.2377	CHLORIDE	1C	4	E,Q,V2
HOWARD	O&G	08		SNYDER FIELD SEEPS (WALSH & WATTS)	OCP#4173	WALSH AND WATTS, INC.	32.2327	-101.2395	CHLORIDE	1C	4	E,Q,V2
HOWARD	O&G	08		SNYDER RUNDOWN	OCP#4964	PLAINS MARKETING L.P.	32.228458	-101.21495	TPH, BTEX, PSH	0	4	E,Q,V2
HUTCHINSON	O&G	10		BORGER FACILITY (LEASE # P002561)	OCP#5154	PHILLIPS 66 PIPELINE, LLC	35.724075	-101.429275	CHLORIDE	0	4	E,Q,V2
HUTCHINSON	O&G	10		CONOCO PHILLIPS JOHNSON TANK FARM	PIT#2561	CONOCO PHILLIPS COMPANY	35.7222	-101.4289	CHLORIDE	1B	3	E,Q,V2
HUTCHINSON	O&G	10		F5 PIPELINE RELEASE	OCP#5267	SCOUT ENERGY MANAGEMENT COMPANY LLC	35.6467	-101.61	TPH, BENZENE, CHLORIDE	1B	3	E,Q,V2
HUTCHINSON	O&G	10		JON A WELL A-1	OCP#5056	KAT ENERGY CORP.	35.66113	-101.44266	TPH, BTEX, PSH	0	4	E,Q,V2
HUTCHINSON	O&G	10		PANHANDLE FIELD COMPRESSOR NO. 06	VCP#40014	PIONEER NATURAL RESOURCES USA, INC	35.6322	-101.6203	TPH, BTEX, PSH	0	6C	E,Q,V2
HUTCHINSON	O&G	10		PATTON CREEK SITE	OCP#1430	PHILLLIPS 66 COMPANY/GPM GAS CORP.	35.69806	-101.38194	TPH	0	5	E,Q,V2
HUTCHINSON	O&G	10		SEC.89. BLK. Z, GC&SF RR SURVEY	OFCU#60331	C & C OIL PRODUCERS, HILL (01257) LEASE	35.7802	-101.3881	CHLORIDE	5	4	E,Q,V2
JACK	O&G	09		C-18 LINE RELEASE (R14-177)	OCP#5083	ENTERPRISE CRUDE PIPELINE LLC	33.29701	-97.95649	TPH, BTEX	0	4	E,Q,V2
JACK	O&G	9		MCCLESKEY WATER WELL	OFCU#103363	9 MILES NW OF JACKSBORO	33.25551	-98.27909	CHLORIDE	5	2B	E,Q,V2
JACKSON	O&G	02		EDNA COMPRESSOR STATION - SOUTH LOCATION	OCP#4279	GULF SOUTH PIPELINE COMPANY, 4909 FM 1822	28.9123	-96.6274	TPH, BTEX, VOCS, NATURAL GAS	0	4	E,Q,V2
JEFFERSON	O&G	3		BC VENTURES	OFCU#60937	BEAUMONT CITY LIMTIS	30.0589	-94.1733	CHLORIDE	5	5	E,Q,V2
JEFFERSON	O&G	03		BEAUMONT MARINE WEST, FORMERLY OILTANKING OPTION, SPINDLETOP FIELD	OCP#1432	ENTERPRISE PRODUCTS OPERATING LLC (FORMERLY OILTANKING BEAUMONT)	30.02167	-94.03917	PSH	1C	5	E,Q,V2
JEFFERSON	O&G	03		BIG HILL BRINE PITS	OCP#1037	CHEVRON (FORMERLY UNOCAL)	29.7575	-94.24472	CHLORIDE	0	4	E,Q,V2
JEFFERSON	O&G	03		CORDTS COMPLAINT, PL RELEASE, TEXAS HIGHWAY 347/MCFADDEN CREEK	OCP#1879	ATLANTIC RICHFIELD (A BP AFFILIATED COMPANY)	30.01639	-94.03944	PSH	1C	5	E,Q,V2
JEFFERSON	O&G	03		SABINE DOCK LINES AOC 1	OCP#3032	MARATHON PETROLEUM COMPANY, LLC	29.7263	-93.90001	TPH, BTEX, PAH, TDS	0	4	E,Q,V2
JEFFERSON	O&G	03		SABINE DOCK LINES AOC 11, 12	OCP#5117	MARATHON PETROLEUM COMPANY, LLC	29.7388	-93.8907	PSH	1B	4	E,Q,V2
JEFFERSON	O&G	03		SABINE DOCK LINES AOC 7	OCP#5114	MARATHON PETROLEUM COMPANY, LLC	29.7319	-93.8955	TPH, BTEX	0	5	E,Q,V2
JEFFERSON	O&G	03		SABINE DOCK LINES AOC 8	OCP#5115	MARATHON PETROLEUM COMPANY, LLC	29.7329	-93.8948	TPH, BTEX, PAH	0	3	E,Q,V2
JEFFERSON	O&G	03		SABINE DOCK LINES AOC 9 AND 10	OCP#5116	MARATHON PETROLEUM COMPANY, LLC	29.735	-93.8933	TPH, BTEX, PAH	0	3	E,Q,V2
JIM HOGG	O&G	04		AGUA NUEVA	OCP#2483	ENTERPRISE	26.933561	-98.583519	TPH, BTEX, PSH	0	4	E,Q,V2
JIM WELLS	O&G	04		CANALES LEASE /LA CABRA RANCH (PIPELINE RELEASE, ZONE F GW CONTAMINATION)	OCP#2321	JETTA OPERATING COMPANY INC. (FORMERLY TRIAD ENERGY CORPORATION)	27.3866	-98.093101	BTEX, CHLORIDE	1C	4	E,Q,V2
JIM WELLS	O&G	04		COMPRESSOR STATION #719	OCP#1829	DCP MIDSTREAM (FORMERLY DUKE ENERGY)	27.68722	-97.94194	TPH, BTEX, PSH	0	4	E,Q,V2
JIM WELLS	O&G	04		ECO MUD DISPOSAL ENFORCEMENT DOCKET 04-0275496	OCP#5007	ECO MUD DISPOSAL	27.58608	-98.11304	TPH, BTEX, VOCS, SVOCS, CHLORIDE	0	3	E,Q,V2
JIM WELLS	O&G	04		KING RANCH WEST STRATTON COMPRESSOR STATION	OCP#4916	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	27.6813	-97.9491	TPH, BTEX, OTHER METALS	0	5	E,Q,V2
JIM WELLS	O&G	04		LA GLORIA GAS PLANT	OCP#1554	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	27.27583	-98.15488	TPH, BTEX, PSH, OTHER METALS	0	6A	E,Q,V2
JIM WELLS	O&G	04		MO VAC CADENA RANCH DISPOSAL PIT	OCP#5236	MO-VAC SERVICES	27.8895	-98.08552	CHLORIDE	3	2	E,Q,V2
JIM WELLS	O&G	04		PODEST PIT	OFCU#106643/ OCP#5014	CORPUS CHRISTI - JEROME PODEST	27.5872	-98.1147	TPH	5	3	E,Q,V2
JIM WELLS	O&G	04		SEELIGSON #2 TRUNK STATION	OCP#5177	FLINT HILLS RESOURCES, LC (FORMERLY KOCH PIPELINE COMPANY)	27.405455	-98.103823	TPH, BTEX	2B	4	E,Q,V2
JIM WELLS	O&G	04		SEELIGSON MOBIL GAS PLANT	OCP#1555	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	27.410189	-98.113107	TPH, BTEX, PSH, OTHER METALS	0	4	E,Q,V2
JONES	O&G	7B		HAWLEY PIPELINE RELEASE	OCP#5106	SUNOCO LOGISTICS, L.P.	32.627112	-99.756131	TPH, BTEX	0	5	E,Q,V2
JONES	O&G	7B		HAWLEY-TO-HAMLIN 8 INCH PIPELINE RELEASE (EUGENE GRIFFITH)	OCP#2042	SUNOCO PIPELINE L.P.	32.631791	-99.881961	TPH	0	4	E,Q,V2
JONES	O&G	7B		HOLLINGSWORTH PROPERTY	COMP#8230	5 MILES NORTH OF TRENT	32.5469	-100.0979	CHLORIDE	3	2A	E,Q,V2
JONES	O&G	7B		VINSON SITE. PROPERTY, MERKEL, TX	OCP#1761	CHEVRON (UNOCAL)	32.5568	-100.001	TPH	2	5	E,Q,V2

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KARNES	O&G	02		BEAM-MEYER TRUNKLINE RELEASE, LEASE NO. 09876	OCP#5087	MARATHON OIL EF LLC	28.837712	-98.039985	TPH, BTEX	0	4	E,Q,V2
KARNES	O&G	02		MAURER MCFARLAND UNIT LEASE RELEASE	OCP#5141	MARATHON OIL EF LLC	28.90483	-98.021074	TPH, BTEX	1D	5	E,Q,V2
KARNES	O&G	02		OPIELA COMPLAINT	OCP#4975	BLACKBRUSH OIL AND GAS, LLC	29.02712	-97.85914	CHLORIDE	1C	6C	E,Q,V2
KENEDY	O&G	04		EL PAISTLE #2 PRIMARY SEPARATOR STATION	OCP#5021	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	27.153	-97.7438	PSH, TPH, BTEX	0	5	E,Q,V2
KENEDY	O&G	04		EL PAISTLE FIELD SEPTEMBER 2010 PIPELINE RELEASE	OCP#4582	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	27.164194	-97.758472	TPH, PSH	0	3	E,Q,V2
KENEDY	O&G	04		EL PAISTLE J SEPARATION STATION	OCP#5020	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	27.15375	-97.7091	TPH, BTEX, PSH	0	4	E,Q,V2
KENEDY	O&G	04		KING RANCH STILLMAN COMPRESSOR STATION	OCP#4911	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	26.6931	-97.9415	TPH, BTEX, OTHER METALS	0	5	E,Q,V2
KENEDY	O&G	04		KING RANCH STILLMAN REMOTE 5	OCP#4925	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	26.6136	-97.9131	TPH, BTEX, OTHER METALS, CHLORIDE	0	5	E,Q,V2
KENEDY	O&G	04		MIFFLIN SEPARATOR STATION	OCP#5022	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	27.1019	-97.7848	BTEX	0	4	E,Q,V2
KENEDY	O&G	04		RITA #75 REMOTE HEADER	OCP#5024	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	26.9895	-97.8562	TPH, BTEX	0	5	E,Q,V2
KENEDY	O&G	04		RITA COMPRESSOR STATION	OCP#5023	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	27.000361	-97.880917	PSH, TPH, BTEX	0	3	E,Q,V2
KENEDY	O&G	04		RITA TANK BATTERY	OCP#5019	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	26.9953	-97.8715	TPH, BTEX, CHLORIDE	0	5	E,Q,V2
KENEDY	O&G	04		SARITA COMPRESSOR STATION	OCP#4453	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	27.2522	-97.7353	TPH, BTEX, CHLORIDE	0	4	E,Q,V2
KLEBERG	O&G	04		EXXON MOBIL STRATTON P286	OCP#5257	EXXON MOBIL STRATTON P286	27.5721	-97.9351	BENZENE	1	1	E,Q,V2
KLEBERG	O&G	04		KING RANCH - TRANQUITAS LAKE DAM AREA	OCP#2431	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	27.5517	-97.9283	TPH	0	4	E,Q,V2
KLEBERG	O&G	04		KING RANCH ALAZAN 205/207 (#3)	OCP#4921	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	27.4657	-97.6087	TPH, BTEX, OTHER METALS, CHLORIDE	0	5	E,Q,V2
KLEBERG	O&G	04		KING RANCH ALAZAN 465 STATION	OCP#4900	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	27.39097	-97.56337	TPH, BTEX, OTHER METALS	0	5	E,Q,V2
KLEBERG	O&G	04		KING RANCH ALAZAN 495	OCP#5191	EOG RESOURCES	27.4861	-97.5911	TPH, BTEX, CHLORIDE	1	4	E,Q,V2
KLEBERG	O&G	04		KING RANCH ALAZAN CENTRAL TANK BATTERY	OCP#4585	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	27.4559	-97.5973	TPH, BENZENE, PSH, CHLORIDE	0	3	E,Q,V2
KLEBERG	O&G	04		KING RANCH ALAZAN EAST REMOTE	OCP#4922	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	27.4575	-97.5942	TPH, BTEX, OTHER METALS, CHLORIDE	0	5	E,Q,V2
KLEBERG	O&G	04		KING RANCH BORREGOS 10 INCH OOS GATHERING LINE	OCP#4924	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	27.4843	-98.0253	TPH, BTEX, OTHER METALS, CHLORIDE	0	5	E,Q,V2
KLEBERG	O&G	04		KING RANCH BORREGOS CENTRAL METER STATION	OCP#4901	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	27.4951	-98.0129	TPH, BTEX, OTHER METALS	0	5	E,Q,V2
KLEBERG	O&G	04		KING RANCH BORREGOS CENTRAL TANK BATTERY	OCP#4902	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	27.4966	-98.0061	TPH, BTEX, OTHER METALS	0	5	E,Q,V2
KLEBERG	O&G	04		KING RANCH BORREGOS E-148	OCP#5157	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	27.430529	-97.960761	TPH, BENZENE	0	5	E,Q,V2
KLEBERG	O&G	04		KING RANCH BORREGOS ME-54 REMOTE HEADER STATION	OCP#4919	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	27.4313	-97.9595	TPH, BTEX, HG, CHLORIDE	0	5	E,Q,V2
KLEBERG	O&G	04		KING RANCH BORREGOS NORTH METER STATION	OCP#4903	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	27.5179	-97.9969	TPH, BTEX, OTHER METALS	0	5	E,Q,V2
KLEBERG	O&G	04		KING RANCH BORREGOS SOUTH COMPRESSOR FACILITY	OCP#4904	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	27.4798	-98.0088	TPH, BTEX, OTHER METALS	0	5	E,Q,V2
KLEBERG	O&G	04		KING RANCH BORREGOS SOUTHWEST COMPRESSOR STATION	OCP#4905	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	27.4872	-98.0439	TPH, BTEX, OTHER METALS	0	5	E,Q,V2
KLEBERG	O&G	04		KING RANCH BORREGOS TANK BATTERY	OCP#4906	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	27.4726	-97.9743	TPH, BTEX, OTHER METALS	0	5	E,Q,V2
KLEBERG	O&G	04		KING RANCH BORREGOS WEST COMPRESSOR STATION	OCP#4907	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	27.5094	-98.0234	TPH, BTEX, OTHER METALS	0	5	E,Q,V2
KLEBERG	O&G	04		KING RANCH CANELO BOA	OCP#4908	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	27.2991	-97.9841	TPH, BTEX, OTHER METALS	0	5	E,Q,V2
KLEBERG	O&G	04		KING RANCH GAS PLANT	OCP#4809	ENERGY TRANSFER COMPANY (FORMERLY EXXONMOBIL PRODUCTION COMPANY)	27.4685	-98.0558	TPH, BENZENE, CHLORIDE	0	4	E,Q,V2

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KLEBERG	O&G	04		KING RANCH MADERO 8 RELEASE	OCP#4923	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	27.4586	-97.6138	TPH, BTEX, OTHER METALS, CHLORIDE	0	5	E,Q,V2
KLEBERG	O&G	04		KING RANCH MADERO METER STATION	OCP#4930	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	27.4635	-97.6348	TPH, BTEX, OTHER METALS, CHLORIDE	0	5	E,Q,V2
KLEBERG	O&G	04		KING RANCH SEELIGSON CENTRAL TANK BATTERY	OCP#4909	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	27.4509	-98.0514	TPH, BTEX, OTHER METALS	0	5	E,Q,V2
KLEBERG	O&G	04		KING RANCH SEELIGSON SEPERATION STATION#1	OCP#4918	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	27.3919	-98.0549	TPH, BTEX, OTHER METALS	0	5	E,Q,V2
KLEBERG	O&G	04		KING RANCH SEELIGSON TANK BATTERY #6	OCP#4910	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	27.45067	-98.03071	TPH, BTEX, OTHER METALS	0	5	E,Q,V2
KLEBERG	O&G	04		KING RANCH STRATTON BATTERY 3	OCP#4926	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	27.5779	-97.9089	TPH, BTEX, OTHER METALS, CHLORIDE	0	5	E,Q,V2
KLEBERG	O&G	04		KING RANCH STRATTON COMSTOCK COMPRESSOR STATION	OCP#4913	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	27.5753	-97.9361	TPH, BTEX, OTHER METALS	0	5	E,Q,V2
KLEBERG	O&G	04		KING RANCH TCB 100 LB GATHERING LINE	OCP#4928	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	27.3482	-98.0323	TPH, BTEX, OTHER METALS, CHLORIDE	0	5	E,Q,V2
KLEBERG	O&G	04		KING RANCH TCB CENTRAL TANK BATTERY	OCP#4914	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	27.3759	-98.0471	TPH, BTEX, OTHER METALS	0	5	E,Q,V2
KLEBERG	O&G	04		KING RANCH TCB CTB VRU DISCHARGE LINE #3	OCP#4927	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	27.3761	-98.0513	TPH, BTEX, OTHER METALS, CHLORIDE	0	5	E,Q,V2
KLEBERG	O&G	04		KING RANCH TCB STATION 2	OCP#4808	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	27.3596	-98.0493	TPH, BTEX, PSH, CHLORIDE	0	5	E,Q,V2
KLEBERG	O&G	04		KING RANCH TCB, 38 REMOTE ROW	OCP#4810	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	27.3768	-98.0011	PSH, TPH, BENZENE, CHLORIDE	0	5	E,Q,V2
KLEBERG	O&G	04		MAY FIELD COMPRESSOR STATION	OCP#3072	EL PASO E&P COMPANY, LP	27.318	-97.744	BENZENE	0	5	E,Q,V2
KLEBERG	O&G	04		SULLIVAN RANCH DEHYDRATION UNIT (RIO PAISANO)	OCP#1260	ENERGY TRANSFER (FORMERLY ENRON/FLORIDA GAS TRANSMISSION)	27.256723	-97.937193	BTEX	1C	5	E,Q,V2
LA SALLE	O&G	01		ARN EF TANK BATTERY	OCP#5025	SILVERBOW RESOURCES OPERATING, LLC FORMERLY SWIFT ENERGY OPERATING, LLC	28.264583	-99.296083	BENZENE	1B	6C	E,Q,V2
LAVACA	O&G	02		STINGRAY PLANT	OCP#5086	PIONEER NATURAL RESOURCES	29.3056	-97.0387	TPH, BTEX, PSH	0	2A	E,Q,V2
LIBERTY	O&G	03		CLEVELAND CREST NO. 1	OFCU#110305	RESACA RESOURCES, LLC	30.2736	-95.0451	BTEX	5	4	E,Q,V2
LIBERTY	O&G	03		CLUBB, A.J. #1 (GREGG ROYALTY)	OFCU#60934	200 ARKANSAS, DAISETTA, TX 77533	30.106861	-94.63911	CHLORIDE	5	5	E,Q,V2
LIBERTY	O&G	03		DAISETTA SINKHOLE	OFCU#60328	106 MAIN STREET, DAISETTA, TX 77533	30.12071	-94.64728	CHLORIDE	5	5	E,Q,V2
LIBERTY	O&G	03		FINLEY NO. 1 AND NO. 2	OCP#4848	FINLEY RESOURCES, INC	30.2728	-95.0356	BTEX	1C	3	E,Q,V2
LIBERTY	O&G	03		FOOTHILLS COMPRESSOR STATION	OCP#4847	FOOTHILLS TEXAS, INC.	30.2935	-95.0446	CHLORIDE	1C	5	E,Q,V2
LIBERTY	O&G	03		NATURAL GAS SEEP, ESPERSON MOORES BLUFF A LEASE	OCP#4182	JAY MANAGEMENT COMPANY, LLC	29.97726	-94.9622	BTEX, NATURAL GAS, CHLORIDE	0	4	E,Q,V2
LIBERTY	O&G	03		ROELING VACUUM	OFCU#61654	6 MILES NE OF LIBERTY	30.1558	-94.6563	CHLORIDE	5	5	E,Q,V2
LIBERTY	O&G	3		TRILATERAL	OFCU#60931	5 MILES NORTH OF RAYWOOD	30.1066	-94.6404	CHLORIDE	5	5	E,Q,V2
LIMESTONE	O&G	05		OLETHA STATION	OCP#1699	LUMINANT/ENERGY FUTURE HOLDINGS	31.4122	-96.4086	TPH, BTEX, PSH, CHLORIDE	0	3	E,Q,V2
LIVE OAK	O&G	02		CLAYTON YARD	OCP#1859	KINDER MORGAN TEXAS PIPELINE, LP	28.32056	-98.27556	TPH, BTEX, CHLORIDE	0	6C	E,Q,V2
LIVE OAK	O&G	02		GEORGE WEST 6" PIPELINE RELEASE	OCP#4954	PLAINS MARKETING, L.P.	28.37391	-98.164642	TPH, BTEX	0	4	E,Q,V2
LIVE OAK	O&G	02		KARON FIELD FACILITY	OCP#4824	COLUMBUS ENERGY, LLC	28.48318	-98.01433	TPH, BTEX, VOCS, PSH, AS, BA, HG, PCB, CHLORIDE	1A	3	E,Q,V2
LIVE OAK	O&G	02		LIVE OAK COMPRESSOR STATION (T4#06544)	OCP#5124	COPANO FIELD SERVICES/SOUTH TEXAS	28.327302	-98.2065	TPH, BTEX	0	5	E,Q,V2
LIVE OAK	O&G	02		THREE RIVERS SWD	OCP#5006	PIONEER NATURAL RESOURCES	28.543287	-98.192019	CHLORIDE	0	4	E,Q,V2
LUBBOCK	O&G	08		STEVE ALTMAN COMPLAINT	COMP#326	ANTON-IRISH FIELD, LEASE #00304	33.8213	-102.0093	CHLORIDE	2	2A	E,Q,V2
LUBBOCK	O&G	8A		RUSSELL RAY COMPLAINT	COMP#5639	CITY OF LUBBOCK	33.6075	-101.7841	CHLORIDE	2	2A	E,Q,V2
MADISON	O&G	03		PATHFINDER CAPITAL	OFCU#60936	3415 TX 21, MADISONVILLE, TX 77864	30.9286	-95.95459	CHLORIDE	5	5	E,Q,V2
MARTIN	O&G	08		GUY Z	OCP#5001	PIONEER NATURAL RESOURCES	32.211332	-102.051393	TPH, BTEX	1A	4	E,Q,V2
MARTIN	O&G	08		HOLT RANCH, GUY TO MABEE PIPELINE SPILL 1	OCP#2196	PLAINS MARKETING, L.P.	32.31611	-102.135	TPH	0	5	E,Q,V2
MARTIN	O&G	08		HOLT RANCH, GUY TO MABEE PIPELINE SPILL 2	OCP#2197	PLAINS MARKETING, L.P.	32.30417	-102.1375	TPH, BTEX	1C	4	E,Q,V2
MARTIN	O&G	08		PIONEER TO MABEE 6-INCH DISCHARGE SITE	OCP#4948	PLAINS PIPELINE L.P.	32.2204	-102.08881	BTEX, CHLORIDE	0	4	E,Q,V2
MARTIN	O&G	08		RK GATHERING	OCP#5102	PLAINS MARKETING, L.P.	32.358108	-101.972208	TPH, BTEX, PAH	0	4	E,Q,V2

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MARTIN	O&G	08		SALE RANCH GAS PLANT	OCP#1089	LOUISVILLE GAS & ELECTRIC, LLC	32.2107	-101.9357	TPH, BTEX, PSH	0	4	E,Q,V2
MARTIN	O&G	08		SALE RANCH N TANK BATTERY	OCP#5230	PIONEER NATURAL RESOURCES	32.1923	-101.9208	CHLORIDE	1A	6A	E,Q,V2
MARTIN	O&G	08		TARZAN BOOSTER STATION	VCP#16006	NAVITAS MIDSTREAM PARTNERS, LLC	32.268243	-101.970207	TPH, VOCS	0	5	E,Q,V2
MATAGORDA	O&G	03		ANGELINA SPENCER LEASE	OCP#1605	DEVON ENERGY (FORMERLY OCEAN ENERGY INC., UMC)	29.06652	-95.82784	CHLORIDE, AS, OTHER METALS	3	5	E,Q,V2
MATAGORDA	O&G	03		MARKHAM GAS PLANT AND ASSOCIATED PROPERTY	OCP#5067	MARATHON OIL COMPANY	29.00861	-96.053473	BTEX, HG, AS	1B	5	E,Q,V2
MATAGORDA	O&G	03		SALLIE JOHNSON (09472) BAY CITY FIELD	OCP#1129	URBAN OIL & GAS GROUP LLC (FORMERLY APACHE CORP.)	29.0415	-95.9431	CHLORIDE	2	5	E,Q,V2
MATAGORDA	O&G	03		VERNON BRIGGS SW DISPOSAL	OFCU#60124	4.5 MILES EAST OF BAY CITY	28.9571	-95.8735	CHLORIDE	5	5	E,Q,V2
MIDLAND	O&G	08		4" SPRABERRY <TREND AREA> GATHERING RELS	OTH#90003	CENTURION PIPELINE, L. P.	31.82411	-101.79462	TPH, PSH	0	4	E,Q,V2
MIDLAND	O&G	08		BUCHANAN A BOOSTER	OCP#5003	PIONEER NATURAL RESOURCES	31.951806	-101.893357	TPH, BTEX, CHLORIDE	0	4	E,Q,V2
MIDLAND	O&G	08	*	BUCHANAN D2 FLOWLINE RELEASE	OCP#5259	PIONEER NATURAL RESOURCES USA, INC.	31.973581	-101.907221	CHLORIDE	1B	3	E,Q,V2
MIDLAND	O&G	08		CITY VIEW ACRES SITE	OCP#3324	PLAINS PIPELINE L.P.	31.9915	-102.0463	TPH	0	5	E,Q,V2
MIDLAND	O&G	08		COLLINS D TANK BATTERY	OCP#5004	PIONEER NATURAL RESOURCES	31.914868	-102.01814	TPH, BTEX, CHLORIDE	0	6A	E,Q,V2
MIDLAND	O&G	08		DORA TO TOWER 8" LEAK SITE	OCP#1992	PLAINS MARKETING (FORMERLY LINK ENERGY, EOTT ENERGY)	31.82639	-102.2211	TPH	0	5	E,Q,V2
MIDLAND	O&G	08		ET O'DANIEL WELL NO. 36	OCP#5110	PIONEER NATURAL RESOURCES	31.94018	-101.82786	BTEX	0	6A	E,Q,V2
MIDLAND	O&G	08		G.D. LOBLEY LEASE	OCP#5206	PIONEER NATURAL RESOURCES	32.068	-102.0319	CHLORIDE, TPH	1C	4	E,Q,V2
MIDLAND	O&G	08		G.R. JACKSON COMPLAINT, CRUDE OIL LINE	OCP#4464	CHEVRON PIPE LINE COMPANY	31.750878	-102.164564	TPH	1C	4	E,Q,V2
MIDLAND	O&G	08		GOOD WATER WELL INVESTIGATION	OCP#4991	ENERGEN RESOURCES CORP.	32.0445	-101.8873	CHLORIDE	1C	5	E,Q,V2
MIDLAND	O&G	08		MIDLAND IRAAN TO MIDLAND BASIN 16"	OCP#5196	PLAINS PIPELINE, L.P.	32.013185	-102.015034	TPH, BTEX	2	4	E,Q,V2
MIDLAND	O&G	08		MIDLAND STATION TANK 5611 RELEASE SITE	OCP#5163	ENTERPRISE CRUDE PIPELINE, LLC	32.023281	-102.012243	TPH, BTEX, PSH	0	4	E,Q,V2
MIDLAND	O&G	08		MIDLAND TANK FARM STATION	OCP#2206	ENTERPRISE PRODUCTS LLC (FORMERLY ENTERPRISE, TEPPCO)	32.01639	-102.0156	TPH, BTEX, PSH	0	4	E,Q,V2
MIDLAND	O&G	08		MUNGLO-LANKFORD (BRANDT) PROPERTY	OCP#1948	PLAINS PIPELINE, L.P. (FORMERLY LINK ENERGY, EOTT ENERGY)	32.0575	-102.03472	TPH	0	5	E,Q,V2
MIDLAND	O&G	08		PARKS (BOOSTER) COMPRESSOR STATION	OCP#1369	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	31.83472	-102.1711	PSH	0	5	E,Q,V2
MIDLAND	O&G	08		PEGASUS GAS PLANT / PEGASUS GATHERING SYSTEM [WATER WELL]	OCP#1371	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	31.6616	-102.138	TPH	1D	5	E,Q,V2
MIDLAND	O&G	08		PMT 16 INCH CRUDE OIL RELEASE	OCP#5085	PLAINS MARKETING, L.P.	32.01202	-102.01668	TPH, BTEX	0	4	E,Q,V2
MIDLAND	O&G	08		PSU 41 CENTRAL TANK BATTERY	OCP#5193	PIONEER NATURAL RESOURCES	31.6915	-101.8012	CHLORIDE	1A	4	E,Q,V2
MIDLAND	O&G	08		ROBERTS RANCH GAS PLANT	OCP#1206	DCP MIDSTREAM, LLC (FORMERLY DUKE ENERGY FIELD SERVICES)	31.7829	-102.2479	BTEX	0	5	E,Q,V2
MIDLAND	O&G	08		TEPPCO 10 IN HISTORICAL TEPPCO RELEASE	OCP#3315	PLAINS ALL AMERICAN PIPELINE, L.P.	32.0211	-102.018	BTEX, PSH	0	4	E,Q,V2
MIDLAND	O&G	08		TEPPCO TANK FARM (FM 1150 AND FM 80)	OCP#1895	PLAINS ALL AMERICAN (FORMERLY LINK ENERGY, EOTT ENERGY)	32.01579	-102.01609	TPH, BTEX, PSH	1B	5	E,Q,V2
MIDLAND	O&G	08		TEXACO E FLOWLINE	OCP#5005	PIONEER NATURAL RESOURCES	32.063995	-101.935578	TPH, CHLORIDE	0	4	E,Q,V2
MIDLAND	O&G	08	*	WINK TO MIDLAND 24" LINE STRIKE	OCP#5248	PLAINS PIPELINE	32.0085	-102.0133	TPH, BENZENE	1B	4	E,Q,V2
MIDLAND	O&G	8A		ET O'DANIEL NO. 6	OCP#5057	PIONEER NATURAL RESOURCES	31.940446	-101.839652	TPH, BTEX	1A	4	E,Q,V2
MILAM	O&G	1		JACKSON PROD- STANISLAW LEASE	OFCU#60299	ROCKDALE	30.7419	-97.0577	BTEX	5	5	E,Q,V2
MONTAGUE	O&G	09		DAVIS NATURAL GAS PLANT (BOWIE, TX)	OCP#1771	WEST TEXAS GAS, INC.	33.5835	-97.8031	TPH	3	3	E,Q,V2
MONTAGUE	O&G	09		JACK GRACE HILL	OFCU#65181	1.8 MILES NW OF BOWIE	33.567747	-97.879694	NATURAL GAS, CHLORIDE	5	2A	E,Q,V2
MONTAGUE	O&G	09		MONTAGUE SALT-WATER DISPOSAL PITS	OCP#2430	MULTIPLE OPERATORS	33.9514	-97.6805	CHLORIDE	1C	2A	E,Q,V2
MONTGOMERY	O&G	03		12" LINE SITE # 35, CONROE FIELD	OCP#2621	SEMGREEN (FORMERLY SEMPIPE)	30.25556	-95.37056	TPH, BTEX, PSH	0	4	E,Q,V2
MONTGOMERY	O&G	03		BP AMERICA PRODUCTION COMPANY	OCP#5162	FORMER BENDER FIELD PRODUCTION FACILITY	30.134299	-95.433707	BENZENE, CHLORIDE, PASH, LEAD, ARSENIC	0	4	E,Q,V2
MONTGOMERY	O&G	03		CONROE GAS PLANT, CONROE FIELD UNIT LEASE (TEXACO ROAD)	OCP#1965	DENBURY (FORMERLY WAPITI OPERATING, EXXON MOBIL CORPORATION)	30.26706	-95.37361	BENZENE, CHLORIDE	2	4	E,Q,V2
MONTGOMERY	O&G	03		CONROE SITE 3	OCP#1485	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	30.27778	-95.35944	BTEX, CHLORIDE	1A	5	E,Q,V2

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MONTGOMERY	O&G	03		FEE NO. 199640001 (TOWNSITE BATTERY)	OCP#4069	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	30.29849	-95.469503	TPH, BENZENE, AS, BA, CD, PB, SE	0	4	E,Q,V2
MONTGOMERY	O&G	03		OLD HUMBLE 4 IN PIPELINE	OCP#4460	DENBURY ONSHORE, LLC	30.2421	-95.3851	TPH, BTEX, PSH, CHLORIDE	0	4	E,Q,V2
MONTGOMERY	O&G	03		PINEHURST TANKS	OCP#5015	DEVON ENERGY PRODUCTION LP	30.206382	-95.680739	TPH, BTEX	1C	3	E,Q,V2
MONTGOMERY	VCP	03	*	EVERGREEN CFU 2051 VCP AREA	VCP# 22006	HIGHWAY 242 AND FM 1314	30.22117	-95.378707	BENZENE, TOULENE, TPH, CHLORIDE	0	1	E,Q,V2
MONTGOMERY	VCP	03	*	EVERGREEN KM27 VCP AREA	VCP# 22005	HIGHWAY 242 AND FM 1314	30.22251145	-95.3799751	BENZENE, TPH	0	1	E,Q,V2
MOORE	O&G	10		BIVINS NATURAL GAS PLANT & COMPRESSOR STATION	OCP#1165	EL PASO NATURAL GAS (FORMERLY CIG)	35.64028	-101.95972	BENZENE, CHLORIDE	0	4	E,Q,V2
MOORE	O&G	10		DUMAS COMPRESSOR STATION CHROMIUM	OCP#5040	KINDER MORGAN INC.	35.8141	-102.0341	TPH	0	4	E,Q,V2
MOORE	O&G	10		PANHANDLE FIELD COMPRESSOR 15	VCP#30015	PIONEER NATURAL RESOURCES USA, INC	35.6363	-101.7172	BTEX, PSH	0	4	E,Q,V2
MOORE	O&G	10		PANHANDLE FIELD COMPRESSOR NO.10	VCP#40012	PIONEER NATURAL RESOURCES USA, INC	35.6352	-101.8224	TPH, BTEX, PSH	1B	4	E,Q,V2
NOLAN	O&G	7B		LAKE TRAMMEL UNIT PIT	OCP#5107	MERIT ENERGY COMPANY	32.34357	-100.44914	TPH, BTEX, CHLORIDE	0	3	E,Q,V2
NOLAN	O&G	7B		WESTLAKE GAS PLANT	OCP#1609	KERR MCGEE (FORMERLY ORYX ENERGY CORP.)	32.29083	-100.4528	CHLORIDE, PSH	0	4	E,Q,V2
NUECES	BROWNFIE LD	04	*	NUECES COUNTY UPPER OSO QUALITY IMPROVEMENT	BRP# 1501	INTERSECTION OF STATE HWAY 44E & MAIN AVE. (CO. RD. 40), ROBSTOWN, TX 78380	27.79944	-97.64389	CHLORIDE, BENZENE CHLORIDE, BENZENE	0	5	E,Q,V2
NUECES	O&G	04		BANQUETE RELEASE SITE	OCP#2477	KOCH PIPELINE COMPANY	27.87376	-97.8191	TPH, BTEX, PAH, SVOCS	0	4	E,Q,V2
NUECES	O&G	04		COASTAL COMPRESSOR STATION, BISHOP	OCP#1190	DCP MIDSTREAM	27.74639	-97.845	BENZENE, PSH	0	5	E,Q,V2
NUECES	O&G	04		DCP ALBRECHT FARMS DT1-21-PL RELEASE	OCP#5199	DCP MIDSTREAM	27.675	-97.6416	TPH, BTEX, CHLORIDE	1	2	E,Q,V2
NUECES	O&G	04		DRISCOLL #3 SITE	OCP#4178	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	27.688142	-97.718261	TPH, BTEX, PAH, VOCS, CHLORIDE	0	3	E,Q,V2
NUECES	O&G	04		FHR SOUTH CRUDE SYSTEM PIPELINE (T4 NO. 00140)	OCP#5183	FLINT HILLS RESOURCES, LC	27.7011961	-97.8985906	TPH, BTEX	0	4	E,Q,V2
NUECES	O&G	04		FLOUR BLUFF PARCEL D	OCP#3532	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	27.65915	-97.27791	TPH, BTEX, PAH	0	3	E,Q,V2
NUECES	O&G	04		FM 1889, ROBSTOWN PIPELINE RELEASE SITE	OCP#2330	KINDER MORGAN / EL PASO MERCHANT ENERGY PETROLEUM COMPANY	27.82444	-97.66389	TPH, BTEX	0	5	E,Q,V2
NUECES	O&G	04		FORMER BANQUETE STATION	OCP#3102	KINDER MORGAN ENERGY INC. (FORMERLY EL PASO MERCHANT ENERGY)	27.8127	-97.7761	TPH, BTEX, PSH	0	5	E,Q,V2
NUECES	O&G	04		GPL-42	OCP#3073	DCP MIDSTREAM, LP (FORMERLY DUKE ENERGY)	27.74376	-97.85541	PSH	0	4	E,Q,V2
NUECES	O&G	04		GULFPLAINS DCP GP4-4 LINE RELEASE	OCP#5241	DCP MIDSTREAM	27.6467	-97.9175	BENZENE	1	2	E,Q,V2
NUECES	O&G	04		HEB CC18 SOUTH WALDRON RD & KNICKERBROCKER ST	VCP#10002	HEB GROCERY COMPANY, LP	27.66542	-97.2815	TPH, BTEX	0	5	E,Q,V2
NUECES	O&G	04		KING RANCH TO VIOLA 8 INCH BUTANE PIPELINE RELEASE SITE - 1.1 MILES NORTH OF FM665	OCP#2320	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	27.68472	-97.69611	PSH, TPH, BTEX, OTHER METALS	1C	5	E,Q,V2
NUECES	O&G	04		MUSTANG ISLAND PRODUCTION/SPERARATION FACILITY	OCP#5166	TRANSCONTINENTAL GAS P.L. CO, LLC - THE WILLIAMS COMPANIES	27.617374	-97.31408	TPH, BTEX	0	5	E,Q,V2
NUECES	O&G	4	*	SEFL CORPUS CHRISTI	VCP#21009	5821 BEAR LANE	27.7612	-97.472	CHLORIDE	0	5	E,Q,V2
NUECES	O&G	04		VITEXOPERATING WALTON W.W. LEASE	OCP#5235	VIRTEX	27.816005	-97.501427	TPH, BTEX, CHLORIDE	1	2	E,Q,V2
NUECES	O&G	04		WARDNER #3 COMPRESSOR STATION, BISHOP	OCP#1800	DCP MIDSTREAM (FORMERLY DUKE ENERGY)	27.68972	-97.93	TPH, BENZENE, PSH	0	5	E,Q,V2
NUECES	O&G	04		WARDNER COMPRESSOR STATION, BISHOP	OCP#1211	DCP MIDSTREAM	27.64583	-97.91417	BENZENE, PSH, BA	0	5	E,Q,V2
NUECES	O&G	04		WILSON STATE TRACT	OFCU#112705	SAMURAI OPERATING COMPANY, LLC	27.904017	-97.71908	TPH, BTEX	5	3	E,Q,V3
NUECES	VCP	04	*	SEFL CORPUS CHRISTI	VCP# 21009	5821 BEAR LANE	27.762178	-97.472031	CHLORIDE	0	5	E,Q,V2
OCHILTREE	O&G	10		PERRYTON-BARLOW COMPRESSOR STATION	OCP#3321	DCP MIDSTREAM, LP	36.361705	-100.727418	TPH, BTEX	0	4	E,Q,V2
OCHILTREE	O&G	10		SPEARMAN PLANT	OCP#2562	NORTHERN NATURAL GAS CO.	36.0866	-101.0518	BTEX	0	5	E,Q,V2

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OCHILTREE	O&G	10		TG- 27801 PIPELINE RELEASE SITE	OCP#5071	DCP MIDSTREAM, LP	36.2708	-100.5492	BTEX, CHLORIDE	1A	4	E,Q,V2
PALO PINTO	O&G	7B		JACK MARTIN COMPLAINT	COMP#10798	2.4 MILES SOUTHEAST OF METCALF GAP	32.67863	-98.42767	TPH, BTEX, PSH, CHLORIDE	1C	2A	E,Q,V2
PALO PINTO	O&G	7B		MILE POST 51.9	OCP#5176	ONEOK PERMIAN NGL OPERATING COMPANY L.L.C.	32.603229	-98.114767	TPH, BTEX	1A	5	E,Q,V2
PALO PINTO	O&G	7B		MINGUS STATION	OCP#2173	PLAINS MARKETING L.P.	32.54778	-98.43472	BTEX	0	5	E,Q,V2
PALO PINTO	O&G	7B		UNIDENTIFIED STUART HEIRS	OFCU#60323	OIL SEEP IONI CREEK	32.652	-98.558	TPH	5	5	E,Q,V2
PANOLA	O&G	06		ALLISON LEASE	OCP#4844	BP AMERICA PRODUCTION COMPANY	32.1600087	-94.378452	BENZENE, NATURAL GAS, CHLORIDE	0	4	E,Q,V2
PANOLA	O&G	06		BEASLEY 3 LEASE, WELL #5	OCP#5187	CONOCOPHILLIPS COMPANY	32.05051	-94.29041	BTEX, CHLORIDE, TDS	0	5	E,Q,V2
PANOLA	O&G	6		BECKVILLE DISPOSAL	OFCU#89644	BECKVILLE	32.2244	-94.4902	CHLORIDE, BENZENE, SODIUM , CADMIUM	5	2B	E,Q,V2
PANOLA	O&G	06		CARTHAGE GAS UNIT (CCU) COMPRESSOR STATION	OCP#4829	MEMORIAL PRODUCTION OPERATING, LLC (FORMERLY WILDHORSE RESOURCES, LLC)	32.193258	-94.253672	CHLORIDE, OTHER METALS	0	5	E,Q,V2
PANOLA	O&G	06		CE MOORE COMPRESSOR STATION	OCP#3593	CCI EAST TEXAS UPSTREAM, LLC (FORMERLY ANADARKO PETROLEUM CORP.)	32.12856	-94.2723	BTEX	1C	4	E,Q,V2
PANOLA	O&G	06		CTI INVESCO, LLC (CTI SWD#1)	OTH#14331	CARTHAGE FIELD, 6 MILES SOUTH OF CARTHAGE	32.050246	-94.290805	CHLORIDE	1C	4	E,Q,V2
PANOLA	O&G	06		D.C. BRANNON WELL NO. 1	OCP#1659	DEVON (FORMERLY SNYDER OIL CORP.)	32.0594	-94.52306	BTEX	0	5	E,Q,V2
PANOLA	O&G	06		DAVIS #1 SWD	OCP#5153	KEY ENERGY SERVICES, LLC	32.354543	-94.189135	CHLORIDE	0	3	E,Q,V2
PANOLA	O&G	06		DEBERRY FACILITY	OCP#4815	SELECT ENERGY SERVICES, LLC	32.3639	-94.067	BENZENE, CHLORIDE	0	4	E,Q,V2
PANOLA	O&G	06		EAST TEXAS GAS PLANT	OCP#1194	DCP (FOMERLY DUKE ENERGY FIELD SERVICES, UPR)	32.18744	-94.26233	TPH	0	4	E,Q,V2
PANOLA	O&G	06		GCU 20 WELL #24	OCP#5119	CCI EAST TEXAS UPSTREAM LLC (FORMERLY ANADARKO E&P ONSHORE)	32.1768	-94.4051	BTEX, CHLORIDE	1C	4	E,Q,V2
PANOLA	O&G	06		MITCHELL AND HALL SWD (BETHANY NE, LIME 3850)	OCP#2202	BASIC ENERGY SERVICES	32.31527	-94.04746	CHLORIDE, BA, NORM	1C	3	E,Q,V2
PARKER	O&G	7B		PHIL BRADBURY WASTE DISPOSAL LINE RELEASE INCIDENT	OCP#3581	XTO ENERGY INC, BARNETT GATHERING	32.7066	-97.9322	CHLORIDE	0	5	E,Q,V2
PARKER	O&G	7B		SPRINGTOWN GAS PLANT	OCP#2537	ENBRIDGE GATHERING L.P.	32.9842	-97.6834	TPH, BTEX	2	5	E,Q,V2
PECOS	O&G	08		GOMEZ GAS PLANT & COMPRESSOR STATION DIAMOND Y	OCP#1572	ENERGY TRANSFER (FORMERLY REGENCY, ANADARKO, NORTHERN NAT. GAS, HOOVER, & WESTERN NAT GAS)	30.99611	-102.9228	PSH	0	5	E,Q,V2
PECOS	O&G	08		ROLLINS WATER WELL	OTH#90004	EMMONS LEASE (04187), VAQUERO OPERATING	30.99033	-102.96705	CHLORIDE	2	4	E,Q,V2
PECOS	O&G	08		SANTA ROSA GAS PLANT	OCP#1092	KINDER MORGAN, INC	31.2389	-102.8886	TPH, BTEX, PSH	0	5	E,Q,V2
PECOS	O&G	08		SCHUYLER WIGHT COMPLAINT	COMP#5437	3 MILES SOUTH OF GRANDFALLS	31.29059	-102.85384	TPH, PSH, CHLORIDE	2	2A	E,Q,V2
POTTER	O&G	10		FAIN GAS PLANT (10-0059) PIT	OCP#4938	PIONEER NATURAL RESOURCES USA, INC.	35.53672	-101.89508	TPH, BTEX	0	5	E,Q,V2
POTTER	O&G	10		PIONEER TANK BATTERY #2	OCP#1776	WILLIAMS ENERGY SERVICES INC	35.5389	-101.8885	TPH, BTEX	0	5	E,Q,V2
REAGAN	O&G	7C		ROCKER BB TO PATTERSON	OCP#4285	PLAINS MARKETING, L.P.	31.42803	-101.54546	TPH, BTEX, PSH	0	4	E,Q,V2
REAGAN	O&G	7C		STILES 4" GATHERING LINE	OCP#3535	PLAINS MARKETING, L.P.	31.41266	-101.3287	TPH	0	5	E,Q,V2
REFUGIO	O&G	02		FM 136 WOODSBORO RELEASE SITE	OCP#5172	FLINT HILLS RESOURCES, L.P.	28.1905045	-97.284268	TPH, BTEX, PSH	0	4	E,Q,V2
REFUGIO	O&G	02		G-7 SWD LAMBERT "G" GATHERING FACILITY	OCP#2203	DEVON ENERGY OPERATING CO., L.P.	28.3427861	-97.1752917	CHLORIDE	1A	4	E,Q,V2
REFUGIO	O&G	02		HEARD RANCH PIG RECEIVER 18 IN LINE	OCP#5122	HOUSTON PIPE LINE COMPANY, L.P.	28.32892	-97.18055	TPH, BTEX	0	6C	E,Q,V2
REFUGIO	O&G	02		TOM O'CONNOR GAS PLANT	OCP#1293	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	28.37561	-97.16807	BTEX, PAH	0	4	E,Q,V2
REFUGIO	O&G	02		TOWN OF REFUGIO	BRP#7003	TOWN OF REFUGIO	28.2945	-97.27	CHLORIDE	5	3	E,Q,V2
RUNNELS	O&G	7C		BALLINGER SEEP	OFCU#60330	NONPOINT SOURCE INVESTIGATION & REMEDEDIATION	31.7284	-99.9283	CHLORIDE	5	4	E,Q,V2
RUSK	O&G	06		ENVIROPAVE RECLAMATION PLANT	OFCU#88043	KILGORE	32.3339	-94.9171	BENZENE, CHLORIDE	5	3	E,Q,V2
RUSK	O&G	06		GRAY GAS UNIT LEASE WELL#7 GAS BREAKOUT	OCP#5149	ROCKCLIFF FORMERLY SAMSON LONE STAR, LLC	32.31075	-94.66635	NATURAL GAS, CHLORIDE	1C	4	E,Q,V2
RUSK	O&G	06		HYLYN BROOKE SWD ANODE BED VENT PIPE WATER RELEASE	OCP#5194	ROCKCLIFF ENERGY OPERATING LL	32.351082	-94.641985	BENZENE, TPH	4A	4	E,Q,V2
RUSK	O&G	06		INLAND RECLAMATION PLANT	OFCU#79844	KILGORE	32.3679	-94.8924	BENZENE, CHLORIDE	5	3	E,Q,V2

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RUSK	O&G	06		LAKE MURVAUL COMPRESSOR STATION	OCP#5178	ENABLE MIDSTREAM PARTNERS	32.059378	-94.627166	BTEX	0	3	E,Q,V2
RUSK	O&G	06		OAKHILL 2712 COMPRESSOR STATION	OCP#3215	CCI EAST TEXAS UPSTREAM, LLC (FORMERLY ANADARKO PETROLEUM CORPORATION)	32.36803	-94.57528	TPH, BTEX	0	4	E,Q,V2
SAN PATRICIO	O&G	04		CHILTIPIN CREEK SEEP SITE	OFCU#62390	SINTON CITY LIMITS	28.0422	-97.5111	TPH	5	4	E,Q,V2
SAN PATRICIO	O&G	04		HOSKINSON WELL NO. A4	OCP#1974	CHEVRON ENVIRON. MANAGEMENT CO. (FORMERLY PURE RESOURCES, INC.)	27.91878	-97.36175	BENZENE, PSH	0	4	E,Q,V2
SAN PATRICIO	O&G	04		INGLESIDE CRUDE OIL TERMINAL	OCP#4822/VCP #21003	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	27.87277	-97.22349	TPH, BENZENE, PSH	0	5	E,Q,V2
SAN PATRICIO	O&G	04		LA QUINTA RD RATTLESNAKE LINE RELEASE	OCP#5140	KOCH PIPELINE	27.903501	-97.283812	TPH, BTEX	1D	4	E,Q,V2
SAN PATRICIO	O&G	04		NARCISCO CANTU WELL 2R SWD FACILITY	OCP#5052	B & D DISPOSAL, LTD	28.053164	-97.524874	BTEX, CHLORIDE	2	2A	E,Q,V2
SAN PATRICIO	O&G	04		TAFT BLASCHKE-MAYO TANK BATTERY	OCP#3066	CHEVRON USA, INC.	28.0554	-97.3705	BENZENE, CHLORIDE	0	3	E,Q,V2
SAN PATRICIO	O&G	04		TAFT OIL FIELD - GAS LIFT PLANT	OCP#3041	CHEVRON U. S. A. INC.	28.03269	-97.382536	CHLORIDE	0	3	E,Q,V2
SAN PATRICIO	O&G	04		TAFT OIL FIELD - GODWIN TANK BATTERY	OCP#3048	CHEVRON U. S. A. INC.	28.0313	-97.373	TPH, CHLORIDE	0	3	E,Q,V2
SAN PATRICIO	O&G	04		TAFT OIL FIELD - MAYO CENTRAL TANK BATTERY	OCP#3030	CHEVRON	28.031105	-97.378125	TPH, CHLORIDE	0	3	E,Q,V2
SAN PATRICIO	O&G	04		TAFT OIL FIELD - SATELLITE STATION #1	OCP#3047	CHEVRON U. S. A. INC.	28.038	-97.3854	TPH, CHLORIDE	0	3	E,Q,V2
SAN PATRICIO	O&G	04		TAFT OIL FIELD - SATELLITE STATION #2	OCP#3043	CHEVRON U. S. A. INC.	28.032012	-97.383095	CHLORIDE	0	3	E,Q,V2
SAN PATRICIO	O&G	04		TAFT WELL NO. 45	OCP#4470	CHEVRON	28.031802	-97.384565	CHLORIDE	0	4	E,Q,V2
SAN PATRICIO	VCP	04	*	DAVID ESTATES - 133.551 ACRES LAND	VCP# 21004	OFF FLOREKE ROAD	27.902644	-97.335957	TPH, CHLORIDE, ARSENIC, LEAD	0	5	E,Q,V2
SCHLEICHER	O&G	7C		HULLDALE GAS PLANT	OCP#1201	DAVIS GAS PROCESSING, INC. (FORMERLY DEFS, UPR)	31.0004	-100.5171	TPH	0	6C	E,Q,V2
SCURRY	O&G	8A		COLORADO CITY STATION - CHINA GROVE CRUDE OIL PIPELINE RELEASE	OCP#3705	CENTURION PIPELINE, L.P.	32.5307	-100.8452	TPH, BENZENE	0	5	E,Q,V2
SCURRY	O&G	8A		DIAMOND "M" PLANT	OCP#1291	KINDER MORGAN PRODUCTION CO. LP (FORMERLY EXXON CO. USA)	32.6736	-101.0883	TPH	3	4	E,Q,V2
SCURRY	O&G	8A		FULLER GAS PLANT	OCP#1676	CHEVRON USA INC. (FORMERLY TEXACO E&P, INC.)	32.9441	-100.8905	TPH, BTEX	1C	5	E,Q,V2
SCURRY	O&G	8A		GINA JACKSON AC MILLS RELEASE	OCP#5063	ENTERPRISE CRUDE PIPELINE LLC	32.528685	-100.935995	TPH, BTEX, PAH	0	4	E,Q,V2
SCURRY	O&G	8A		NORTH SNYDER STATION	OCP#4457	KINDER MORGAN	32.8412	-100.9214	TPH, PSH	0	5	E,Q,V2
SCURRY	O&G	8A		SACROC UNIT DEEP BURIAL PITS	OCP#5093	KINDER MORGAN PRODUCTION COMPANY, LLC	32.8363	-100.9273	TPH, CHLORIDE	0	4	E,Q,V2
SCURRY	O&G	8A		SACROC UNIT, TRACT 216	OCP#4459	KINDER MORGAN PRODUCTION COMPANY	32.7359	-100.9953	TPH, PSH	0	4	E,Q,V2
SCURRY	O&G	8A		SACROC WELL SITE 213, #2A	OCP#1863	KINDER MORGAN	32.7416	-100.9816	TPH	1B	4	E,Q,V2
SHACKELFORD	O&G	7B		PETTY SEEP	OFCU#60199	SHACKELFORD COUNTY REG, PETTY PROPERTY	32.9418	-99.5443	CHLORIDE	5	5	E,Q,V2
SMITH	O&G	06		EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	OCP#5190	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	32.4872	-95.2544	BENZENE, TPH	0	1	E,Q,V2
<olSMITH	O&G	06		SAND FLAT TO HAWKINS PIPELINE	OCP#5190	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	32.4872	-95.2544	BENZENE, TPH	0	1	E,Q,V2
SMITH	O&G	06		TAYLOR LEASE DISPOSAL STATION	OCP#5080	BASIC ENERGY SERVICES, L.P.	32.332847	-95.102077	TPH, BTEX, AS, SE, CHLORIDE	0	3	E,Q,V2
STARR	O&G	04		C.V. DE LOPEZ 'A' LEASE	OCP#3599	DEWEY BELLOWS OPERATING COMPANY, LTD	26.669469	-98.428317	TPH, BTEX	0	3	E,Q,V2
STARR	O&G	04		DELMITA GAS PLANT	OCP#2871	ENTERPRISE HYDROCARBONS (EPCO)	26.6579	-98.4819	TPH, BTEX	0	3	E,Q,V2
STARR	O&G	04		DELMITA GATHERING -PIPELINE #508 RELEASE	OCP#4579	ENTERPRISE PRODUCTS OPERATING LLC	26.615444	-98.540472	TPH, BENZENE	0	4	E,Q,V2
STARR	O&G	04		KELSEY FIELD - MCGILL BROS. METER SITE 3	OCP#4292	OVERTON PARK OIL & GAS (FORMERLY EXXONMOBIL CORPORATION)	26.782791	-98.41947	TPH, BTEX, CHLORIDE	0	3	E,Q,V2
STARR	O&G	04		KELSEY FIELD - SOUTHEAST SEPARATION STATION	OCP#4293	OVERTON PARK OIL & GAS (FORMERLY EXXONMOBIL CORPORATION)	26.77512	-98.34419	TPH, BTEX, CHLORIDE	0	3	E,Q,V2

COUNTY	DIVISION	DISTRICT	NEW	FILE NAME	FILE NUMBER	LOCATION	LATITUDE	LONGITUDE	CONTAMINANTS	ESC	ASC	DATA QUALITY
STARR	O&G	04		KELSEY FIELD METER SITE 9	OCP#4978	OVERTON PARK OIL & GAS (FORMERLY EXXONMOBIL CORPORATION)	26.770377	-98.398612	TPH, BTEX, OTHER METALS, CHLORIDE	0	4	E,Q,V2
STARR	O&G	04		KELSEY FIELD SOUTHEAST REMOTE STATION	OCP#4979	OVERTON PARK OIL & GAS (FORMERLY EXXONMOBIL CORPORATION)	26.769566	-98.36266	TPH, BTEX, OTHER METALS, CHLORIDE	0	4	E,Q,V2
STARR	O&G	04		KELSEY FIELD STATION C	OCP#4981	OVERTON PARK OIL & GAS (FORMERLY EXXONMOBIL CORPORATION)	26.769444	-98.389167	TPH, BTEX, OTHER METALS, CHLORIDE	0	4	E,Q,V2
STARR	O&G	04		LA REFORMA GUERRA F.B. "B" LEASE WELL NO. 15 FLOWLINE RELEASE	OCP#4996	WHITE OAK OPERATING COMPANY, LLC (FORMERLY MILAGRO EXPLORATION, LLC)	26.65706	-98.39803	TPH, BTEX	0	4	E,Q,V2
STARR	O&G	04		MARIO DURAN COMPLAINT (AKA DURAN AND LONGORIA PROPERTIES)	OCP#1070	KOCH PIPELINE COMPANY, LP	26.71667	-98.52528	TPH, BTEX, PSH	1C	5	E,Q,V2
STARR	O&G	04		SAMANO, M. (07975) LEASE	OCP#5147	TRINITY RIVER ENERGY OPERATING, LLC	26.386945	-98.554633	TPH, BENZENE	5	1	E,Q,V2
STARR	O&G	04		THOMPSON PROPERTY DELMITA PIPELINE #508	OCP#5042	ENTERPRISE HYDROCARBONS LP	26.637512	-98.488328	TPH, BTEX	0	3	E,Q,V2
STEPHENS	O&G	7B		BRECKENRIDGE GAS PLANT	OCP#2557	HANLON (FORMERLY DYNEGY)	32.72527	-98.8811	TPH, BTEX, PAH, VOCS, SVOCS	0	3	E,Q,V2
TAYLOR	O&G	7B		BILBREY WATER WELL	OCP#5012	VENTEX OPERATING CORP.	32.50816	-100.06433	TPH, BTEX, CHLORIDE	2	3	E,Q,V2
TAYLOR	O&G	7B		BOONE PROPERTY	COMP#7743	5 MILES NORTHWEST OF TYE	32.5205	-99.9087	CHLORIDE	2	4	E,Q,V2
TAYLOR	O&G	7B		MERKEL GATHERING	OCP#3081	PLAINS PIPELINE, L.P.	32.3744	-99.8392	TPH	0	4	E,Q,V2
TERRY	O&G	8A		ADAIR CO2 INJECTION FACILITY	OCP#5061	APACHE CORPORATION	32.964	-102.302	TPH, BTEX, VOCS, SVOCS	0	5	E,Q,V2
TOM GREEN	O&G	7C		MANDI-INJECTO	OFCU60204	BUBENIK (STRAWN) FIELD, 6.5 MILES SW SAN ANGELO	31.3679	-100.6147	CHLORIDE	5	4	E,Q,V2
TYLER	O&G	03		ARCO STERNE FEE LEASE	OCP#2029	PREMIUM EXPLORATION COMPANY	30.6562	-94.11761	BTEX, CHLORIDE	3	2A	E,Q,V3
UPSHUR	O&G	06		BARBEE GAS UNIT NO. 1, WELL #4 (176408)	OCP#1540	MCBEE OPERATING CO.	32.77722	-95.02833	TPH, BTEX	1C	4	E,Q,V2
UPSHUR	O&G	6E		EVERETT LAKE SWD LEASE	OCP#5151	EAST TEXAS SALT WATER DISPOSAL CO.	32.56059	-94.93697	BTEX, TDS, CHLORIDE	0	5	E,Q,V2
UPTON	O&G	7C		BENEDUM GAS PLANT	OCP#1036	WTG (WEST TEXAS GAS) BENEDUM JOINT VENTURE	31.3622	-101.7791	TPH, HG	0	6C	E,Q,V2
UPTON	O&G	7C		CTB COMPRESSOR STATION	OCP#1325	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	31.6362	-102.1475	TPH	0	5	E,Q,V2
UPTON	O&G	7C		MCCAMEY 6" HISTORICAL	OCP#5101	PLAINS PIPELINE L.P.	31.136868	-102.192539	TPH, BTEX	0	4	E,Q,V2
UPTON	O&G	7C		WILSHIRE GATHERING LINE	OCP#4284	PLAINS MARKETING, L.P.	31.3953	-102.2151	TPH, BTEX	0	4	E,Q,V2
UPTON	O&G	7C		WILSHIRE LEAK - OIL GATHERING SYSTEM	OCP#1278	PLAINS MARKETING, L.P. (FORMERLY LINK ENERGY, EOTT ENERGY)	31.40194	-102.2436	TPH, BTEX, PSH	0	4	E,Q,V2
UPTON	O&G	7C		WILSHIRE PLANT	OCP#1246	WTG (WEST TEXAS GAS) BENEDUM JOINT VENTURE	31.4431	-102.1881	TPH	0	4	E,Q,V2
VAN ZANDT	O&G	05		ENAS PIT SITE	OCP#1872	CHEVRON (FORMERLY UNOCAL, PURE RESOURCES)	32.50972	-95.63361	TPH, BENZENE, CHLORIDE	0	5	E,Q,V2
VAN ZANDT	O&G	05		FORMER EDGEWOOD GAS PLANT (R3 05-1423)	OCP#1772	ANADARKO PETROLEUM CORP (FORMERLY WESTERN GAS RESOURCES INC)	32.69278	-95.83306	BTEX, PH	0	5	E,Q,V2
VICTORIA	O&G	02		FLINT ENERGY SERVICES YARD	VCP#14005	JANET S. MILLER	28.77569	-96.9703	CHLORIDE	0	4	E,Q,V2
VICTORIA	O&G	02		PLACEDO RANCH	OCP#2195	ACOCK/ANAQUA OPERATING CO., LP	28.72194	-96.79	BTEX, CHLORIDE	2	3	E,Q,V2
VICTORIA	O&G	02		QRV VICTORIA EXPANSION PROJECT	VCP#20004	QRV VICTORIA EXPANSION, LLC	28.78166667	-96.98361111	TPH	1B	4	E,Q,V2
VICTORIA	O&G	02		SAN PATRICIO FIELD DEHYDRATOR	OCP#1090	AURORA RESOURCES CORPORATION (FORMERLY HPL/AEP/ENRON/ET)	28.640853	-96.84881	TPH, BTEX	0	4	E,Q,V2
WARD	O&G	8	*	ANTINA RANCH ESTES #27 WELL SITE	OCP#5276	CHEVRON MID-CONTINENT BUSINESS UNIT	31.446493	-102.771219	CHLORIDE, RADIONUCLIDES	1B	4	E,Q,V2
WARD	O&G	08		CRMWD WELL NO. D2	COMP#5482	8 MILES NORTHEAST OF PYOTE	31.6409	-103.0643	BENZENE	2	1B	E,Q,V2
WARD	O&G	08		MONAHANS STATION	OCP#3586	PLAINS PIPELINE, L.P.	31.6126	-102.944	BENZENE, PSH	0	4	E,Q,V2
WARD	O&G	08		SEALY SMITH FOUNDATION	OCP#5239	OCCIDENTAL PERMIAN, LTD	31.6441	-102.876	BENZENE	2	1	E,Q,V2
WEBB	O&G	04		HUMVERTO GONZALES WATER WELL COMPLAINT	OCP#5215	WALLIS ENERGY	27.541983	-98.824389	BTEX	1	2	E,Q,V2
WEBB	O&G	04		PETTY A2 DISCHARGE 8" NATURAL GAS GATHERING PIPELINE	OCP#5104	ETC TX PIPELINE, LTD., FORMERLY ENERGY TRANSFER COMPANY FIELD SERVICES, LLC, (FORMERLY REGENCY FIELD SERVICES, LLC)	28.14861	-99.83057	TPH, BTEX	0	4	E,Q,V2

COUNTY	DIVISION	DISTRICT	NEW	FILE NAME	FILE NUMBER	LOCATION	LATITUDE	LONGITUDE	CONTAMINANTS	ESC	ASC	DATA QUALITY
WEBB	O&G	04		PETTY RANCH LEASE, TANK BATTERY A-2	OCP#2190	WHITE OAK ENERGY (FORMERLY KERNS OIL AND GAS, ST. MARY LAND & EXPLORATION)	28.10972	-99.84944	TPH, BTEX	1A	4	E,Q,V2
WEBB	O&G	04		STANLEY RANCH RELEASE	OCP#5160	ANADARKO (FORMERLY SN EF MAVERICK, LLC)	28.1359	-99.6811	BTEX, PSH, TDS, CHLORIDE	0	4	E,Q,V2
WHARTON	O&G	03		COCKBURN, H.C. LEASE	OCP#1980	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	29.14083	-96.04	CHLORIDE	1C	5	E,Q,V2
WHARTON	O&G	03		COLORADO RIVER SEEP, H.C. COCKBURN LEASE, STATE TRACT 8B, WHARTON COUNTY	OCP#2213	BP ARCO	29.135	-96.04167	TPH, PSH	1C	2A	E,Q,V2
WHARTON	O&G	03	*	WINTERMAN CENTRAL TANK BATTERY 2017 LOADOUT PIPELINE CONDENSATE RELEASE	OCP#5246	WHITE OAK OPERATING COMPANY	29.471842	-96.281494	LNAPL, BENZENE	1B	4	E,Q,V2
WHARTON	O&G	03		WINTERMAN LEASE, BONUS FIELD	OCP#2425	WHITE OAK OPERATING COMPANY, LLC (FORMERLY MILAGRO EXPLORATION, TEXCAL AKA VENOCO, POGO PRODUCING COMPANY)	29.47194	-96.28111	TPH, BTEX, PSH	0	4	E,Q,V2
WHEELER	O&G	10		APACHE STILES 3 #803	OCP#5069	TAPSTONE ENERGY, LLC	35.44932	-100.040701	TPH, BTEX	0	6C	E,Q,V2
WHEELER	O&G	10		MILLS RANCH #2-97 TANK BATTERY (LEASE NO. 195531)	OCP#5002	ENERQUEST OPERATING, LLC (FORMERLY BRIGHAM OIL & GAS, L.P.)	35.2913	-100.0731	TPH, BTEX	0	4	E,Q,V2
WHEELER	O&G	10		VAN ZANDT WELL	OCP#4288	MULTIPLE OPERATORS (CHEVRON USA)	35.47872	-100.40347	TPH, BTEX	1C	3	E,Q,V2
WICHITA	O&G	9		SUNSHINE HILL	OFCU#60818	7 MILES EAST OF ELECTRA	34.0579	-98.79706	CHLORIDE	5	2B	E,Q,V2
WILLACY	O&G	04		KING RANCH STILLMAN REMOTE METER SITE #18	OCP#4912	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	26.5898	-97.9067	TPH, BTEX, OTHER METALS	0	5	E,Q,V2
WILLACY	O&G	04		KING RANCH TORDILLA COMPRESSOR STATION	OCP#4920	EXXONMOBIL ENVIRONMENTAL AND PROPERTY SOLUTIONS COMPANY	26.57534	-97.89488	TPH, BTEX, OTHER METALS	0	5	E,Q,V2
WINKLER	O&G	08		CRITTENDON FIELD (CITY OF MIDLAND) TUBB 1- A	OCP#4175	HERITAGE STANDARD CORPORATION	31.9526	-103.2995	CHLORIDE	1C	4	E,Q,V2
WINKLER	O&G	08		HALLEY GAS PLANT	OCP#4933	ENERGY TRANSFER COMPANY (FORMERLY REGENCY ENERGY PARTNERS, TRANSWESTERN PL CO. SOUTHERN UNION GAS)	31.73039	-102.9934	BENZENE, PSH	0	4	E,Q,V2
WINKLER	O&G	08		NORTH 16-INCH PIPELINE RELEASE	OCP#3584	PLAINS PIPELINE, L.P.	31.764	-103.17547	PSH	0	4	E,Q,V2
WINKLER	O&G	08		NORTHERN NATURAL GAS KERMIT COMPRESSOR STATION	OCP#5088	NORTHERN NATURAL GAS	31.8103694	-103.073975	TPH, BTEX, NATURAL GAS	0	4	E,Q,V2
WINKLER	O&G	08		SOUTH KERMIT GAS PLANT	OCP#1684	CHEVRON (FORMERLY TEXACO E&P, INC.)	31.8825	-103.05667	BTEX, PSH	1A	4	E,Q,V2
WINKLER	O&G	08		VEST-PIGMON RANCH PROJECT	OCP#4987	CHEVRON ENVIRONMENTAL MANAGEMENT COMPANY	31.7646145	-103.065039	CHLORIDE, TDS	1C	4	E,Q,V2
WINKLER	O&G	08		WALTON PLANT	OCP#1117	CABOT CORPORATION	31.89667	-103.1425	TPH, BTEX, PSH	0	4	E,Q,V2
WINKLER	O&G	08		WHEELER PUMP STATION	OCP#1053	SHELL PIPELINE COMPANY, LP (FORMERLY GLOBAL SOLUTIONS, EQUILON PIPELINE)	31.8472	-102.8025	TPH, BTEX, PSH, CHLORIDE	0	5	E,Q,V2
WINKLER	O&G	08		WINK NORTH 24-INCH PIPELINE RELEASE	OCP#3585	PLAINS PIPELINE, L.P.	31.764	-103.1754722	BTEX, PSH	0	4	E,Q,V2
WISE	O&G	09		CHICO GATHERING SYSTEM ALLEN COMPLAINT	OCP#4839	TARGA NORTH TEXAS, LP	33.22671	-97.40027	TPH, BTEX, PSH, NATURAL GAS	1C	6A	E,Q,V2
WISE	O&G	09		CHICO STATION CRUDE OIL RELEASE	OCP#4811	ENTERPRISE CRUDE PIPELINE, LLC (RED RIVER CRUDE PIPELINE LLC)	33.3067	-97.8476	TPH	0	4	E,Q,V2
WOOD	O&G	6		C&R - EARL LEE	OFCU#60099	4187 FM 14, HAWKINS, TX	32.684	-95.2506	CHLORIDE, BENZENE	5	2B	E,Q,V2
WOOD	O&G	06		CRAWFORD LEASE	OCP#1044	ENERGY PRODUCTION CO.	32.705994	-95.345623	CHLORIDE	1C	4	E,Q,V2
WOOD	O&G	06		FORMER VAN FOLGER PROPERTY , UNIT-GREER COBB LEASE	OCP#1677	APACHE CORPORATION	32.57833	-95.19472	TPH, CHLORIDE	1C	5	E,Q,V2
WOOD	O&G	06		HAWKINS GAS PLANT	OCP#4994	XTO ENERGY INC. (FORMERLY EXXONMOBIL)	32.6105	-95.1953	TPH, AS	0	5	E,Q,V2
WOOD	O&G	06		JAMES WILSON COMPLAINT	COMP#2754	OAK GROVE	32.8024	-95.3984	CHLORIDE	1C	4	E,Q,V2
WOOD	O&G	06		MARIGALE SWD DISPOSAL	OFCU#60116	B&N TRUCKING	32.80965	-95.3847	BENZENE, CHLORIDE	5	5	E,Q,V2
WOOD	O&G	06		QUITMAN STATION	OCP#4009	ENERGY TRANSFER COMPANY (FORMERLY REGENCY, EAGLE ROCK)	32.83611	-95.48778	TPH, BTEX	0	4	E,Q,V2
WOOD	O&G	06		WEST YANTIS GAS PLANT	OCP#1122	BP (FORMERLY AMOCO PRODUCTION CO.)	32.955	-95.63194	TPH, BTEX, CHLORIDE	0	5	E,Q,V2

COUNTY	DIVISION	DISTRICT	NEW	FILE NAME	FILE NUMBER	LOCATION	LATITUDE	LONGITUDE	CONTAMINANTS	ESC	ASC	DATA QUALITY
YOAKUM	O&G	8A		DENVER CITY RELEASE SITE	OCP#2484	OXY USA (FORMERLY ARCO (BP PIPELINES))	32.9591	-102.8433	TPH, BTEX, PSH	1C	5	E,Q,V2
YOAKUM	O&G	8A		PRENTICE BOOSTER STATION	OCP#1087	OXY USA (FORMERLY AMOCO)	33.2724	-102.5972	TPH, BTEX, PSH	0	4	E,Q,V2
YOAKUM	O&G	8A		ROBERTS UNIT LEASE (RAY MARION COMPLAINT)	OCP#1131	APACHE CORPORATION	33.0072	-102.9583	BENZENE, CHLORIDE	1C	5	E,Q,V2
YOAKUM	O&G	8A		SHELL DENVER CITY PLANT	COMP#139	WASSON FIELD, 3 MILES NORTH OF DENVER CITY	32.997432	-102.817472	CHLORIDE	0	4	E,Q,V2
YOAKUM	O&G	8A		WASSON GAS PLANT	OCP#3427	OXY USA (FORMERLY OCCIDENTAL PERMIAN LTD)	33.0061	-102.8097	TPH, BTEX, PSH, CHLORIDE	0	4	E,Q,V2
ZAPATA	O&G	04		J MOSS LANDTREATMENT	OFCU#124305	J MOSS INVESTMENTS	27.020482	-99.082479	PSH, MTALS, CHLORIDES	5	2	E,Q,V2

Exhibit 30.04

This exhibit was not previously submitted in November 2023

United States
Environmental Protection
Agency

Office of Solid Waste
and Emergency Response
Washington, DC 20460

EPA/530-SW-88-003
December 1987

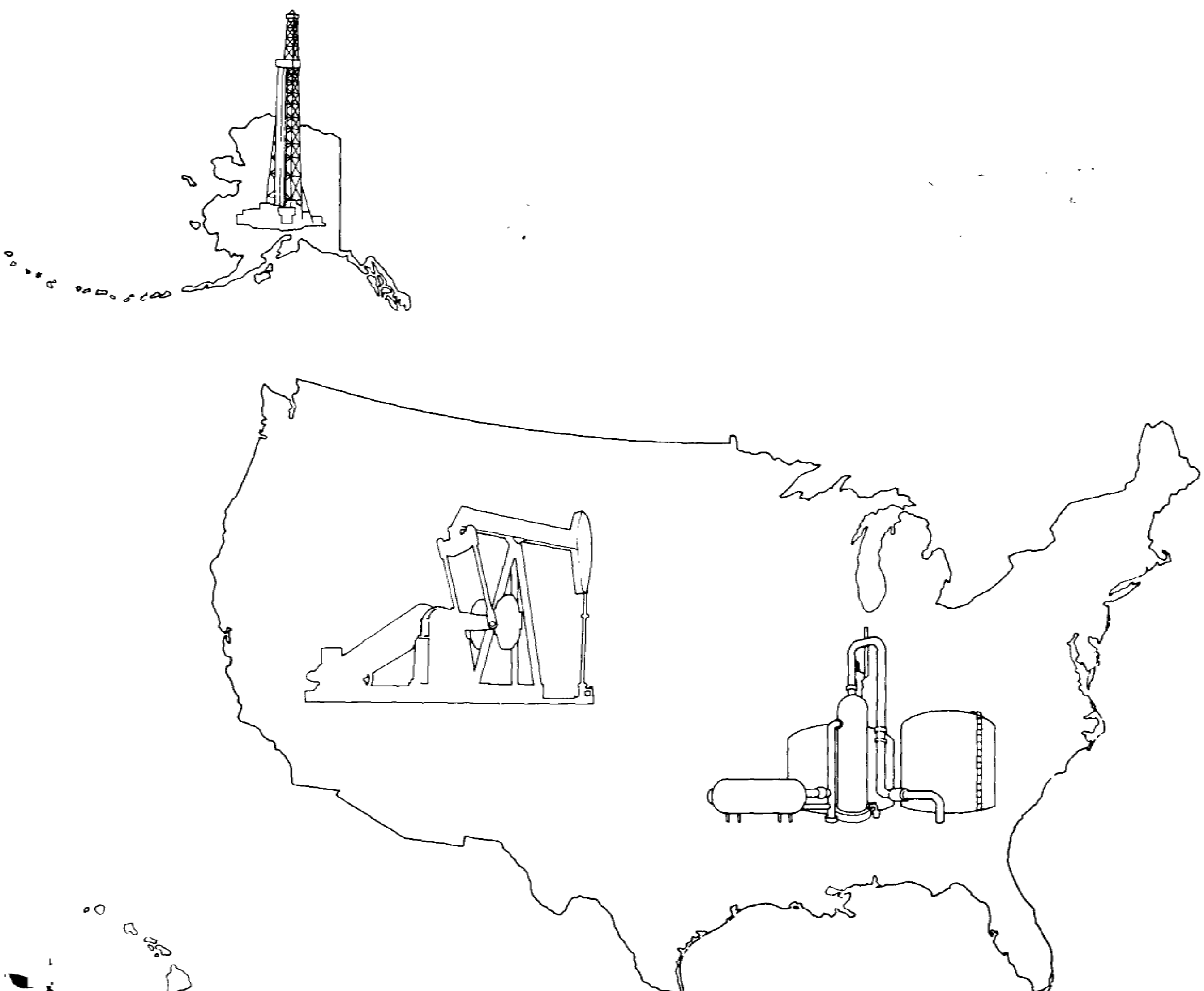
Solid Waste

EPA

Report to Congress

Management of Wastes from the Exploration, Development, and Production of Crude Oil, Natural Gas, and Geothermal Energy

Volume 1 of 3
Oil and Gas



EPA/530-SW-88-003 v.1

REPORT TO CONGRESS

MANAGEMENT OF WASTES FROM THE EXPLORATION, DEVELOPMENT, AND PRODUCTION OF CRUDE OIL, NATURAL GAS, AND GEOTHERMAL ENERGY

VOLUME 1 OF 3

OIL AND GAS

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

Office of Solid Waste and Emergency Response
Washington, D.C. 20460

December 1987

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In West Virginia in 1985, 1,839 new wells were completed at an average depth of 4,270 feet. Only 18 exploratory wells were drilled in that year. In Pennsylvania 4,627 new wells were completed in 1985 to an average depth 2,287 feet; 59 exploratory wells were drilled in that year. Activity in Ohio is developmental rather than exploratory, with only 78 exploratory wells drilled in 1985 out of a total of 6,297 wells completed. The average depth of a new well in 1985 was 3,760 feet.

Types of Operators

Oil and gas production in the Appalachian Basin is dominated by small operators, some well-established, some new to the industry. Major companies still hold leases in some areas. Since most extraction in this zone is economically marginal, many operators are susceptible to market fluctuations.

Major Issues

Contamination of Ground Water from Reserve Pits

Damage case incidents resulting from unlined reserve pits, with subsequent migration of contaminants into ground water, are found in the State of Ohio.

> In 1982, drilling activities of an unnamed oil and gas company contaminated the well that served a house and barn owned by a Mr. Bean, who used the water for his dairy operations. Analysis done on the water well by the Ohio Department of Agriculture found high levels of barium, iron, sodium, and chlorides. (Barium is a common constituent of drilling mud.) Because the barium content of the water well exceeded State standards, Mr. Bean was forced to shut down his dairy operations. Milk produced at the Bean farm following contamination of the water well contained 0.63 mg/L of barium. Concentrations of chlorides, barium, iron, sodium, and other residues in the water well were above the U.S. EPA's Secondary Drinking Water Standards. Mr. Bean drilled a new well, which also became contaminated. As of September 1984, Mr. Bean's water

well was still showing signs of contamination from the drilling-related wastes. It is not known whether Mr. Bean was able to recover financially from the disruption of his dairy business. (OH 49)[4]

This case is a violation of current Ohio regulations regarding drilling mud and produced waters.

Illegal Disposal of Oil Field Wastes in Ohio

Illegal disposal of oil field wastes is a problem in Ohio, as elsewhere, but the State is making an aggressive effort to increase compliance with State waste disposal requirements and is trying to maintain complete and up-to-date records. The State has recently banned all saltwater disposal pits. A legislative initiative during the spring of 1987 attempted to overturn the ban. The attempt was unsuccessful.

The Miller Sand and Gravel Co , though an active producer of sand and gravel, has also served as an illegal disposal site for oil field wastes. An investigation by the Ohio Department of Natural Resources (DNR) found that the sand and gravel pits and the surrounding swamp were contaminated with oil and high-chloride produced waters. Ohio inspectors noted a flora kill of unspecified size. Ohio Department of Health laboratory analysis of soil and liquid samples from the pits recorded chloride concentrations of 269,000 mg/L. The surrounding swamp chloride concentrations ranged from 303 mg/L (upstream from the pits) to 60,000 mg/L (area around the pits). This type of discharge is prohibited by State regulations. (OH 45)[5]

This discharge was a violation of State regulations.

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[4] References for case cited: Ohio EPA, Division of Public Water Supply, Northeast District Office, interoffice communication from E. Mohr to M. Hilovsky describing test results on Mr. Bean's water well, 7/21/86. Letters from E. Mohr, Ohio EPA, to Mr. Bean and Mr. Hart explaining water sampling results, 10/20/82. Letter from Miceli Dairy Products Co. to E. Mohr, Ohio EPA, explaining test results from Mr. Bean's milk and water well. Letters from E. Mohr, Ohio EPA, to Mr. Bean explaining water sampling results from tests completed on 10/7/82, 2/2/83, 10/25/83, 6/15/84, 8/3/84, and 9/17/84. Generalized stratigraphic sequence of the rocks in the Upper Portion of the Grand River Basin.

[5] References for case cited: Ohio EPA, Division of Wastewater Pollution Control, Northeast District Office, interoffice communication from E. Mohr to D. Hasbrauck, District Chief, concerning the results from sampling at the sand and gravel site. Ohio Department of Health, Environmental Sample Submission Reports from samples taken on 6/22/82.

Louisiana's more marginal operations may be particularly stressed by the new Rule 29B, which requires the closing out and elimination of all current and future onsite produced water disposal pits by 1989. Estimated closing costs per pit are $20,000.

Operators in southern Louisiana tend to be major companies and large independents. They are less susceptible to fluctuating market conditions in the short term. Projects in the south tend to be larger than those in the north and are located in more environmentally sensitive areas.

Major Issues

Ground-Water Contamination from Unlined Produced Water Disposal Pits and Reserve Pits

Unlined produced water disposal pits have been used in Louisiana for many years and are only now being phased out under Rule 29B. Past practice has, however, resulted in damages to ground water and danger to human health.

In 1982, suit was brought on behalf of Dudley Romero et al. against operators of an oil waste commercial disposal facility, PAB Oil Co. The plaintiffs stated that their domestic water wells were contaminated by wastes dumped into open pits in the PAB Oil Co. facility which were alleged to have migrated into the ground water, rendering the water wells unusable. Oil field wastes are dumped into the waste pits for skimming and separation of oil. The pits are unlined. The PAB facility was operating prior to Louisiana's first commercial oil field waste facility regulations. After promulgation of new regulations, the facility continued to operate for 2 years in violation of the new regulations, after which time the State shut down the facility.

The plaintiff's water wells are downgradient of the facility, drilled to depths of 300 to 500 feet. Problems with water wells date from 1979. Extensive analysis was performed by Soil Testing Engineers, Inc., and U.S. EPA, on the plaintiff's water wells adjacent to the site to determine the probability of the well contamination coming from the PAB Oil Co. site. There was also analysis on surface soil contamination. Soil Testing

Engineers, Inc., determined that it was possible for the wastes in the PAB Oil Co. pits to reach and contaminate the Romeros' water wells. Surface sampling around the perimeter of the PAB Oil Co site found high concentrations of metals. Resistivity testing showed that plumes of chloride contamination in the water table lead from the pits to the water wells. Borings that determined the substrata makeup suggested that it would be possible for wastes to contaminate the Romero ground water within the time that the facility had been in operation if the integrity of the clay cap in the pit had been lost (as by deep excavation somewhere within it). The pit was 12 feet deep and within range to percolate into the water-bearing sandy soil.

The plaintiffs complained of sickness, nausea, and dizziness, and a loss of cattle. The case was settled out of court. The plaintiffs received $140,000 from PAB Oil Co. (LA 67)[24]

Unlined commercial disposal pits are now illegal in Louisiana.

The ground in this area is highly permeable, allowing pit contents to leach into soil and ground water. Waste constituents potentially leaching into ground water from unlined pits include arsenic, cadmium, chromium, copper, lead, nickel, zinc, and chlorides. There have been incidents illustrating the permeability of subsurface formations in this area.[25]

Allowable Discharge of Drilling Mud into Gulf Coast Estuaries

Under existing Louisiana regulations, drilling muds from onshore operations may be discharged into estuaries of the Gulf of Mexico. The State issues permits for this practice on a case-by-case basis. These

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[24] References for case cited: Soil Testing Engineers, Inc., Brine Study, Romero, et al., Abbeville, Louisiana, 10/19/82. U.S. EPA lab analysis of pits and wells, 10/22/81. Dateline, Louisiana: Fighting Chemical Dumping, by Jason Berry, May-June, 1983.

[25] A gas well operated by Conoco, which had been plugged and abandoned, blew out below the surface from December 11, 1985, to January 9, 1986. The blowout sent gas through fault zones and permeable formations to the land surface owned by Claude H. Gooch. The gas could be ignited by a match held to the ground. The gas was also determined to be a potential hazard to drinking water wells in the immediate area.

Unlined Reserve Pits

Problems with unlined reserve pits are illustrated in the following cases.

Between February 9 and 27, 1986, the Elliott #1 was drilled on the property of Mr. Lawrence Koehling. The Hutchinson Salt member, an underground formation, was penetrated during the drilling of Elliott #1. The drilling process dissolved between 100 and 200 cubic feet of salt, which was disposed of in the unlined reserve pit. The reserve pit lies 200 feet away from a well used by Mr. Koehling for his ranching operations. Within a few weeks of the drilling of the Elliott #1, Mr. Koehling's nearby well began to pump water containing a saltwater drilling fluid.

Ground water on the Koehling ranch has been contaminated with high levels of chlorides allegedly because of leaching of the reserve pit fluids into the ground water. Water samples taken from the Koehling livestock water well by the KCC Conservation Division showed a chloride concentration of 1650 mg/L. Background concentrations of chlorides were in the range of 100 to 150 ppm. It is stated in a KCC report, dated November 1986, that further movement of the saltwater plume can be anticipated, thus polluting the Koehling domestic water well and the water well used by a farmstead over 1 mile downstream from the Koehling ranch. It is also stated in this KCC report that other wells drilled in the area using unlined reserve pits would have similarly affected the groundwater.

The KCC now believes the source of ground-water contamination is not the reserve pit from the Elliott #1. The KCC has drilled two monitoring wells, one 10 feet from the edge of the reserve pit location and the other within 400 feet of the affected water well, between the affected well and the reserve pit. The monitoring well drilled 10 feet from the reserve pit site tested 60 ppm chlorides. (EPA notes that it is not known if this monitoring well was located upgradient from the reserve pit.) The monitoring well drilled between the affected well and the reserve pit tested 750 ppm chlorides. (EPA notes that the level of chlorides in this monitoring well is more than twice the level of chlorides allowed under the EPA drinking water standards). The case is still open, pending further investigation. EPA believes that the evidence presented to date does not refute the earlier KCC report, which cited the reserve pit as the source of ground-water contamination, since the recent KCC report does not suggest an alternative source of contamination. (KS 05)[45]

Unpermitted reserve pits are in violation of current Kansas regulations.

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[45] References for case cited: Summary Report, Koehling Water Well Pollution, 22-10-15W, KCC, Conservation Division, Jim Schoof, Chief Engineer, 11/86.

Leaching of Reserve Pit Constituents into Ground Water

Leaching of reserve pit constituents into ground water and soil is a problem in the Texas/Oklahoma zone. Reserve pit liners are generally not required in Texas and Oklahoma. When pits are constructed in permeable soil without liners, a higher potential exists for migration of reserve pit constituents into ground water and soil. Although pollutant migration may not always occur during the active life of the reserve pit, problems can occur after closure when dewatered drilling mud begins to leach into the surrounding soil. Pollutants may include chlorides, sodium, barium, chromium, and arsenic.

On November 20, 1981, the Michigan-Wisconsin Pipe Line Company began drilling an oil and gas well on the property of Ralph and Judy Walker. Drilling was completed on March 27, 1982. Unlined reserve pits were used at the drill site. After 2 months of drilling, the water well used by the Walkers became polluted with elevated levels of chloride and barium (683 ppm and 1,750 ppb, respectively). The Walkers were forced to haul fresh water from Elk City for household use. The Walkers filed a complaint with the Oklahoma Corporation Commission (OCC), and an investigation was conducted. The Michigan-Wisconsin Pipe Line Co. was ordered to remove all drilling mud from the reserve pit.

In the end, the Walkers retained a private attorney and sued Michigan-Wisconsin for damages sustained because of migration of reserve pit fluids into the freshwater aquifer from which they drew their domestic water supply. The Walkers won their case and received an award of $50,000.[55] (OK 08)[56]

Constructing a reserve pit over a fractured shale, as in this case, is a violation of OCC rules.

In 1973, Horizon Oil and Gas drilled an oil well on the property of Dorothy Moore. As was the common practice, the reserve pit was dewatered, and the remaining mud was buried on site. In 1985-86, problems from the buried reserve pit waste began to appear. The reserve pit contents

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55 API states that the Oklahoma Corporation Commission is in the process of developing regulations to prevent leaching of salt muds into ground water.

56 References for case cited: Pretrial Order, Ralph Gail Walker and Judy Walker vs. Michigan-Wisconsin Pipe Line Company and Big Chief Drilling Company, U.S. District Court, Western District of Oklahoma, #CIV-82-1726-R. Direct Examination of Stephen G. McLin, Ph. D. Direct Examination of Robert Hall. Direct Examination of Laurence Alatshuler, M D. Lab results from Walker water well.

Exhibit 30.05

This exhibit was not previously submitted in November 2023

November 3, 2023

Rules Coordinator
Office of General Counsel
Railroad Commission of Texas

Submitted electronically to rulescoordinator@rrc.texas.com

RE: Proposed Changes to 16 TAC 3.8

I am submitting comments as a former executive in the oilfield waste treatment, recycling, and disposal industry. Over the last 15 years, I've seen firsthand dramatic changes in the national energy landscape including widespread adoption of hydraulic fracturing and directional drilling. While these practices have helped solidify Texas as an energy powerhouse, they have also significantly changed the velocity in which these wastes are generated, as well as the total volume and types of wastes generated during an oil and gas well's life cycle.

For decades, oil and gas operators have been allowed to dispose of their drilling, completion, and production wastes by utilizing unlined pits located at the well or land applying directly upon surrounding ranch land. While these disposal methods were previously necessary from an economic standpoint due to limited third-party disposal capacity and long drive times, this is simply no longer the case – particularly in Texas.

Yet, Texas has not substantially updated its Ch. 8 regulations regarding onsite disposal since the late 1980's. Under the Resource Conservation and Recovery Act (RCRA), both the EPA *and* states are required to periodically review and revise regulations and policy relating to drilling waste management. The last major modifications to state rules relating to drilling waste occurred over two decades ago.

The industry should continue to thrive in Texas with limited federal encroachment. To better ensure that this is the case, immediate attention to modernization drilling waste management practices is urgently required.

After reviewing the draft Rule, there are critical items that need to be addressed and/or improved.

Landowner consent for permanent disposal via an onsite reserve pit must be required (pertinent Section - §4.114(g)(2)):

Most people outside of the oil and gas industry are unaware of the size, volume, contents, and scale of oil and gas operator practices for utilizing pits for permanent disposal of wastes generated from drilling activities. These pictures illustrate that impact[1]:

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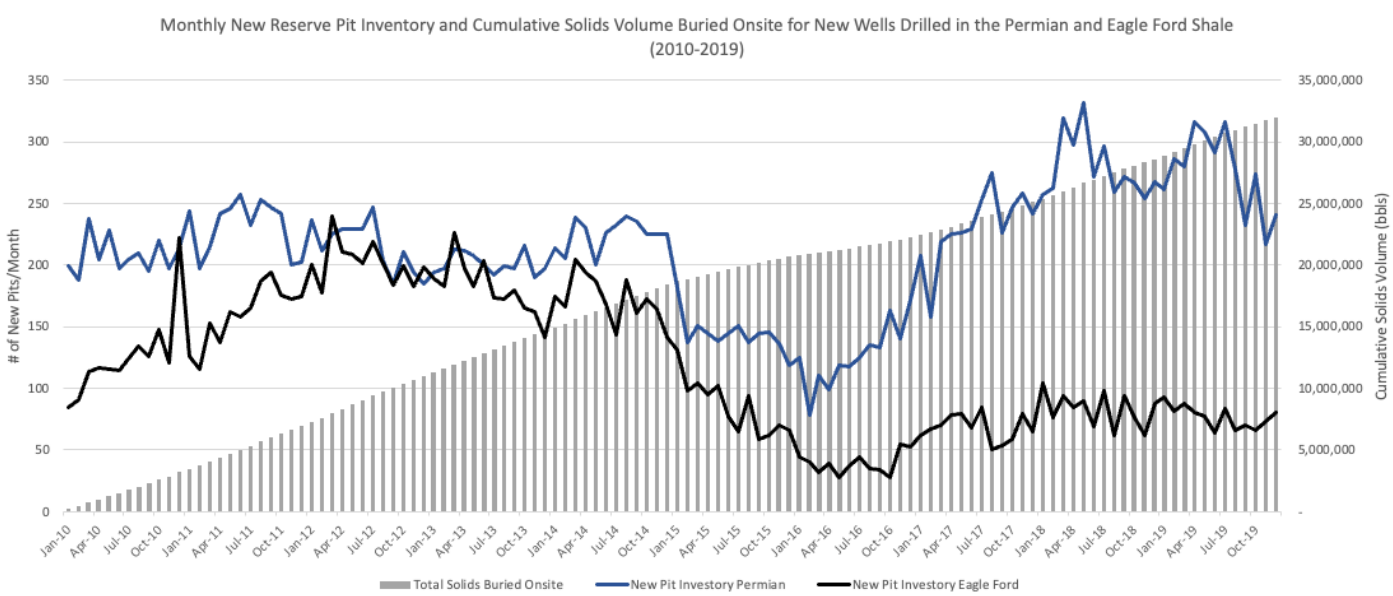
[1] The images are from pits located in the Texas Permian Basin


Pit Full of Drilling Fluids
Significant Drill Cuttings Accumulation Outside of Pit Wall


Two Reserve Pits Utilized for Multi-Well Pad
Closed Pit Nearly Size of Well Pad
Two Reserve Pits Utilized for Multi-Well Pad
Pit 1 Closed

The vast majority of solid wastes generated in the region are managed onsite and ultimately disposed of in pits on location at the well site.

In fact, over a 10-year period between 2010-2019, it's estimated that thirty million barrels of waste were permanently buried onsite in over forty thousand pits…just in the Permian and Eagle Ford alone (*see* chart).[2]



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[2] Assumes roughly 75% of wells drilled utilize onsite disposal via burial and 500-700 barrels of waste per pit.

Per §4.111(d)(2) of the draft Rule, surface owner permission *is* required for disposal via landfarming at the wellsite. To be consistent, prior to closing a pit whereby waste is to be permanently disposed of via onsite burial, surface owner written permission must be required, especially due to the scale, impact to land use, and risk of groundwater contamination.

Commercial Facility Market Assessment Should be Required for New Applicants (pertinent Section §4.140 "Additional Requirements for Commercial Facilities"):

Oil and gas waste management companies have invested hundreds of millions of dollars in infrastructure to handle the increasing volume generated via drilling activity, including multi-lined landfills and injection wells for slurry disposal that can accommodate waste material to ensure the safety of the environment and the public. Nearly every drilling rig in the primary Texas shale Basin's are located within an approximately 30-minute drive time of an RRC permitted, professionally managed disposal facility.

Since 2010, there have been dozens of commercial disposal permits awarded throughout Texas, even and especially during prolonged downturns in drilling activity. While the added disposal capacity was necessary to meet unprecedented demand for proper and safe management of oil and gas wastes generated by increased drilling activity, too much capacity impacts commercial viability and increases long-term liability from bad actors. A market assessment should become part of the permit considerations for new commercial applicants.

I personally would like to thank the Railroad Commission staff for their diligent, hard work to on this rule making process and for the opportunity to provide comments. While I am no longer working within the industry affected by these rules, I am passionate about ensuring they are implemented. No doubt there are many interested parties here. However, the changes recommended herein are with the intent of establishing a more proactive and thoughtful approach on a couple of key issues in order to modernize drilling waste management best practices, enhance transparency, reduce long-term liability risks while asserting Texas's right to govern energy waste practices occurring within the state.

Respectfully submitted,

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Exhibit 30.06

This exhibit was not previously submitted in November 2023

Incidental Take Beneficial Practices: Oil Pits and Produced Water | U.S. Fish & Wildlife Service

Incidental Take Beneficial Practices: Oil Pits and Produced Water

During oil well drilling and operation, water and other waste fluids like drilling muds, concentrated salts, hydrocarbons, and toxic materials are produced. To separate the crude oil from produced water and other drilling fluids, a number of different earthen pits are constructed including reserve pits, skim pits, and flare pits. Once the drilling fluids have been separated, they are typically disposed of in evaporation ponds. These open-top pits, tanks, and containers pose a threat to migratory birds.

How do oil and gas pits impact migratory birds?

Oil waste pits and evaporation ponds can entrap birds that are attracted to a perceived source of water. Entrapped birds may not be able to get out of a pit due to sticky oil fluids, impaired feathers, or steep, synthetically lined pit walls. Birds that land on or fall into a pit become covered with oil and may ultimately die from drowning, starvation, cold or heat stress, or effects of ingested oil.

Why does this happen?

From the air, birds may have trouble distinguishing wetlands and other bodies of water from small pits, ponds, and reservoirs containing oil. They may be attracted to pits and open tanks used to store and separate oil from produced water due to the presence of insets. Birds may approach oil-covered pits and ponds to drink and fall into the pits or become entrapped if the banks of the pits are oiled.

What can I do?

Solutions to preventing bird mortality in oil pits and evaporation ponds are fairly simple and straightforward and are being implemented by many oil operators. Closed containment systems reduce the amount of drilling waste produced, require little to no maintenance, and can be moved from site to site, potentially reducing operator costs. These systems are the safest method to prevent bird exposure to oil and other hazardous chemicals and can eliminate soil contamination and remediation expense.

If a closed containment system is not used, pits and ponds less than 1 acre can be netted or fenced to prevent bird access. However, netting is only a viable practice if it is properly constructed and maintained.

All open-top containers should be covered to prevent entrapment, and any oil or waste fluid spill or leak should be cleaned up immediately.

Library Documents

- USFWS Mountain-Prairie Region Environmental Containments website
- Migratory Bird Mortality in Oilfield Wastewater Disposal Facilities
- USFWS Best Practices for Migratory Bird Care During Oil Spill Response

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Exhibit 30.07

This exhibit was not previously submitted in November 2023

U.S. Fish & Wildlife Service

Migratory Bird Mortality in Oilfield Wastewater Disposal Facilities

Wyoming Ecological Services Field Office - Environmental Contaminants Program

Commercial and centralized oil field wastewater disposal facilities (COWDFs), pose a significant risk to migratory birds and other wildlife because they use large evaporation ponds (either passive or with aeration) to dispose of and treat oil and gas exploration and production wastes. An estimated 500,000 to 1 million birds are lost annually throughout the United States in oil field production skim pits and COWDFs.

Oilfield wastewater disposal facility. USFWS/Pedro Ramirez, Jr.

Wastewater in COWDFs is initially discharged into a receiving pit to separate the oil from the water. The greatest amount of oil tends to float to the surface in the skim pit. Water from receiving pits is often sent to another pit or series of pits for evaporation or other management. COWDFs are typically regulated by state agencies with oversight by the U.S. Environmental Protection Agency primarily under the Oil Pollution Act and the Resource Conservation and Recovery Act. Migratory birds are protected by the Migratory Bird Treaty Act. Companies may be held liable should migratory bird mortalities occur in COWDFs or oil pits.

Oil, Sheens & Hydrocarbons

Oil on the surface of evaporation ponds can entrap birds. Birds can also ingest toxic quantities of oil by preening their oil-covered feathers. Oil also damages the insulation provided by feathers. Visible sheens on ponds are just as deadly to birds that come into contact with them. A light sheen will coat the bird's feathers with a thin film of oil. Although a sheen of oil on the bird may not immediately immobilize the bird, it will compromise the feathers' ability to insulate the bird. The affected bird will ingest the oil when it preens its feathers and suffer chronic effects. The bird could suffer mortality depending on the severity of the chronic effects and the amount of oil ingested. Mortality or morbidity may result depending on the amount of oil coating the animal, the species, prior condition of the animal, the amount of stress incurred by the animal after oiling, and weather conditions.

Oily sludges soaked into the dike can seep back onto the pond surface, especially during the summer when warm temperatures can mobilize the oil. Rainfall events or snowmelt will wash oil from the dike back into the pond.

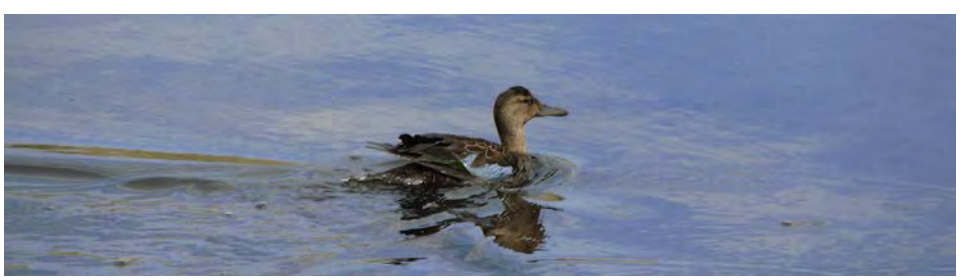
Salt Toxicity

Birds using COWDF ponds with hypersaline water can ingest the brine and die from sodium toxicity or can suffer chronic effects especially if a source of freshwater is not available nearby. Birds preening the salt crystals off their feathers can ingest the salt (as little as 4 grams of salt can be lethal to birds). During cooler temperatures, sodium crystallizes on the feathers of birds landing in these ponds. The sodium crystals destroy the feathers' thermoregulatory and buoyancy functions causing the bird to die of hypothermia or from drowning. Sodium intoxication can cause neurological impairment resulting in the bird's inability to hold its head upright. The bird's head will droop into the water and cause it to drown.

Surfactants and other chemicals

If the evaporation pond is receiving produced water from oil or natural gas wells, oil and gas production chemicals, such as corrosion inhibitors and surfactants, could be present in the wastewater and could pose a risk to migratory birds. Extreme pH in the wastewater can also adversely affect birds landing on the evaporation ponds. Surfactants (i.e. soap) are used to free oil or gas from the reservoir rock formation.

When a bird comes into contact with water containing surfactants, the surfactant will reduce the surface tension of the water; thus, allowing water to penetrate through the feathers and onto the skin. This compromises the insulation properties of the feathers and subjects the bird to hypothermia. The loss of water repellency by the feathers due to reductions in surface tension will cause the bird to become water logged and the loss of buoyancy will cause the bird to drown.



Oil-covered blue-winged teal in COWDF evaporation pond. USFWS/Pedro Ramirez, Jr.

Surfactants in evaporation ponds can cause bird mortality. USFWS/ Pedro Ramirez, Jr.

Eared grebe with salt crystals on feathers. Hypersaline evaporation ponds can result in bird mortality due to salt toxicity. USFWS/Pedro Ramirez, Jr.

Oil-covered elk calf found at edge of COWDF evaporation pond. USFWS/ Pedro Ramirez, Jr.

Grebes and ducks recovered at COWDF evaporation pond. USFWS/Pedro Ramirez, Jr.

Solving the Problem

Solutions to migratory bird mortality at COWDFs are fairly simple and straight forward.

- Use Closed Containment Systems - Closed containment systems should be used to store oil at COWDFs. Closed containment systems eliminate soil contamination and remediation expense.

- Keep Oil Off Open Ponds – COWDFs should be designed to prevent oil from entering evaporation ponds. A contingency plan should be developed for the facility to ensure immediate clean up of oil discharged into the evaporation pond to prevent wildlife mortalities.

- Use Effective & Proven Wildlife Deterrents or Exclusionary Devices – If open-topped tanks or pits will be used to store oil at the facility, effective wildlife exclusionary devices should be installed to prevent wildlife mortality. Netting appears to be the most effective method of keeping birds from entering wastewater evaporation ponds and skim pits. Flagging is not an effective deterrent.

- Implement Engineering Controls to Prevent Oil Discharge to Evaporation Ponds –Engineering controls should be designed and implemented to prevent the discharge of wastewater containing oil and surfactants into the evaporation pond.

- Dispose of Oil Field Wastewater by Deep Well Injection – Deep well injection of oil field wastewater eliminates the need for evaporation ponds.

Evaporation pond with oil on surface. USFWS/Pedro Ramirez, Jr.

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http://www.fws.gov/mountain-prairie/contaminants/contaminants1b.html
May 2009

Exhibit 30.08

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Bird Mortality in Oil Field Wastewater Disposal Facilities

Pedro Ramirez Jr.

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Abstract Commercial and centralized oilfield wastewater disposal facilities (COWDFs) are used in the Western United States for the disposal of formation water produced from oil and natural gas wells. In Colorado, New Mexico, Utah, and Wyoming, COWDFs use large evaporation ponds to dispose of the wastewater. Birds are attracted to these large evaporation ponds which, if not managed properly, can cause wildlife mortality. The U.S. Fish and Wildlife Service (USFWS) and the U.S. Environmental Protection Agency (EPA) conducted 154 field inspections of 28 COWDFs in Wyoming from March 1998 through September 2008 and documented mortality of birds and other wildlife in 9 COWDFs. Of 269 bird carcasses recovered from COWDFs, grebes (Family Podicipedidae) and waterfowl (Anatidae) were the most frequent casualties. Most mortalities were attributed to oil on evaporation ponds, but sodium toxicity and surfactants were the suspected causes of mortality at three COWDFs. Although the oil industry and state and federal regulators have made much progress in reducing bird mortality in oil and gas production facilities, significant mortality incidents continue in COWDFs, particularly older facilities permitted in the early 1980's. Inadequate operation and management of these COWDFs generally results in the discharge of oil into the large evaporation ponds which poses a risk for birds and other wildlife.

Keywords Bird mortality · Evaporation ponds · Oil · Surfactants · Wastewater · Produced water

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Introduction

Mortality of birds and other wildlife in oil field production skim pits has been well documented (Esmoil and Anderson 1995, Flickinger and Bunck 1987, Flickinger 1981, Grover 1983, Lee 1990, Ramirez 2005, Trail 2006). However, there is little information in published literature on bird and wildlife mortality in commercial and centralized oilfield wastewater disposal facilities (COWDFs), which use evaporation ponds to dispose of the oilfield wastewater. The evaporation ponds typically range in size from less than 0.4 hectare (ha) (1 acre) in size to 2 ha (5 acres). Birds attracted to skim pits and COWDF evaporation ponds can become entrapped and die if the pit and pond fluids contain oil or other harmful chemicals. Commercial disposal facilities are operated for profit and receive produced water from one or more oil and gas operators. A centralized disposal facility is owned and operated by the same oil and gas company that operates the wells generating the produced water disposed of into the facility.

In Colorado, New Mexico, Utah, and Wyoming, oil and gas operators use COWDFs for produced water disposal. COWDFs operate under permits issued by state oil and gas or environmental regulatory agencies. Oil and gas operators must dispose of 18 billion barrels (bbls) of water each year from onshore oil and gas production facilities (Veil and others 2004). The American Petroleum Institute (API) estimates that 21% of produced water is injected for disposal, 5% is discharged to surface waters to benefit livestock and wildlife, and 3% is disposed of in commercial or centralized disposal facilities (NETL 2005). According to the API estimate, 12 million bbls of produced water are transported to commercial or centralized wastewater disposal facilities for disposal.

Demand for natural gas is increasing at approximately 1 trillion cubic feet per year (Bryner 2006). In Wyoming, the number of natural gas producing wells increased from 2,600 in 1990 to 23,734 wells in 2005 (EIA 2007). Additional COWDFs to handle produced water from this increase in natural gas development may result in an increase in bird mortality if the COWDFs are not designed and managed properly.

The objective of this article is to present data from field inspections of COWDFs in Wyoming conducted by the U.S. Fish and Wildlife Service (USFWS) and the U.S. Environmental Protection Agency (EPA) between 1998 and 2008, with particular emphasis on mortality of birds and other wildlife at these facilities, the causes of mortality, operation and maintenance practices contributing to the risk of mortality, and management recommendations to prevent or minimize that risk.

Operation of Disposal Facilities in Wyoming

Oil and natural gas are separated from produced water at or near the wellhead using gravity separation in a vertical or horizontal separator (Veil and others 2004). Heater treaters are used to further separate the water from emulsified oil using heat; however, this treatment is not very efficient (Veil and others 2004). Produced water from the heater treater is discharged into waste pits or skim ponds for further gravity separation of oil from water. Produced water is removed from conventional natural gas with glycol or other dehydration chemicals in gas separators (Veil and others 2004). The produced water is typically stored in storage tanks near the wellhead. The produced water can contain petroleum condensates and paraffin, as well as corrosion inhibitors, scale inhibitors, acids, and surfactants added to the well bore to stimulate or enhance production (OTA 1992). Produced water from conventional natural gas wells is typically 10 times more toxic than water produced from oil wells (Jacobs and others 1992).

Produced water is transported from the oil or natural gas fields by vacuum trucks to COWDFs where it is discharged into storage tanks, earthen-diked containment ponds or pits, or directly into the evaporation ponds. The wastewater is discharged from the bottom of the skim pit or tanks to the evaporation ponds. Some COWDFs have a series of tanks and/or pits to maximize oil–water separation.

Causes of Mortality in Oil and Gas Wastewater Disposal Facilities

Poor maintenance of separator pits may cause large quantities of oil to remain on a pond's surface where it can entrap and kill birds and other wildlife (Esmoil and Anderson 1995). Birds, including hawks, owls, and songbirds, are attracted to oil skim pits which resemble ponds of water. Skim pits and evaporation ponds at COWDFs also can attract bats, insects, amphibians, reptiles, small mammals, and big game (Ramirez 2005). Songbirds and mammals may approach oil-covered pits and evaporation ponds to drink, and can fall into the pits, or they can become entrapped in oil on the banks of the pits and evaporation ponds. Synthetic liners in evaporation ponds can become slippery when coated with oil or water and can cause wildlife to fall into the pond. Insects entrapped in the oil can also attract songbirds, bats, and small mammals (Trail 2006). Hawks and owls become victims when they are attracted by struggling birds or small mammals.

The sticky nature of oil entraps wildlife in the pits and they die from exposure and exhaustion (Flickinger 1981; Trail 2006). Wildlife that does manage to escape can die from starvation or the toxic effects of oil ingested during preening (Albers 2003). Birds ingesting sublethal doses of oil can experience impaired reproduction (Albers 2003; Grau and others 1977; Hartung 1965). Cold stress can kill the animal if oil damages the insulation provided by feathers or fur (Hartung 1967). Animals not killed in the pits can suffer ill effects later from contact with the oil and chemicals in the pits (Hartung and Hunt 1966; Albers 2003). If they absorb or ingest oil in less than toxic amounts they may suffer a variety of systemic effects and may become more susceptible to disease and predation (Albers 2003). Visible sheens in the pits or receiving waters also pose a threat to nesting aquatic birds as microliter amounts of oil applied externally to eggs are extremely toxic to bird embryos (King and LeFever 1979; Leepen 1976; Szaro 1979).

Although most operators are aware of the risk that oil on the surface of pits or ponds poses to birds and other wildlife, operators are generally unaware of the risk posed by other chemicals, such as surfactants, in the produced water or hydraulic fracturing fluids disposed of in COWDFs. Surfactants can reduce the surface tension of the water; thus, allowing water to penetrate through feathers and onto the skin. This compromises the insulation properties of the feathers and subjects the bird to hypothermia (Lustick 1976). The reduced surface tension will also cause the bird to become waterlogged and the loss of buoyancy will cause the bird to drown.

COWDFs and U.S. Environmental Laws

COWDFs are subject to several federal environmental laws enacted to protect water quality and the environment, and wildlife (Trail 2006). Wildlife protection laws, such as the Migratory Bird Treaty Act (MBTA) (16 USC 703-711); the Endangered Species Act of 1973 (16 USC 1531-1544), and the Bald and Golden Eagle Protection Act (16 USC 668-668d), are triggered if bird mortality occurs in COWDFs. The USFWS Office of Law Enforcement is responsible for the enforcement of these Acts. Environmental laws that apply to COWDFs include: Section 7003 of the Resource Conservation and Recovery Act (RCRA), the Clean Water Act (CWA) §311(b) (3) & (4) and the Oil Pollution Act of 1990 §1002 (OPA). RCRA Section 7003 allows EPA to order corrective actions to abate threats caused by waste management practices that may present an "imminent and substantial endangerment" to human health or the environment (EPA 1997). The EPA is responsible for enforcing RCRA, CWA, and OPA.

Field Inspections of Oil and Gas Wastewater Disposal Facilities

In 1996, the USFWS Region 6 and the EPA Region 8 launched an inter-agency effort to address wildlife mortality in oil pits and COWDFs in the Rocky Mountain States as well as in North Dakota and South Dakota. The USFWS/EPA Oil and Gas Environmental Assessment Team identified problem oil pits from aerial surveys conducted in Colorado, Montana, North Dakota, South Dakota, Utah and Wyoming from 1997 through 1999 (EPA 2003). In response to environmental compliance concerns from state and federal regulatory agencies in Wyoming, the USFWS and EPA conducted follow up inspections of oil production sites and COWDFs beginning in 1998. The inspections focused primarily on compliance with RCRA and the MBTA.

Follow up field inspections by the EPA and USFWS were conducted from 1998 through 2008 on COWDFs in Wyoming as requested by the Wyoming Department of Environmental Quality (WDEQ). We conducted 154 field inspections of 28 COWDFs (Table 1). Of the 28 COWDFs, 19 were commercial facilities and 9 were centralized. The number of total inspections per facility from 1998 through 2008 ranged from one to 34 inspections (Table 1) with the average number of inspections per year for each facility ranging from 1 to 4. COWDFs with environmental compliance issues and/or a history of bird mortality received more inspections.

Oil–water separation skim pits and evaporation ponds were assessed for the presence of sheens and oil on the surface. The facility inspectors walked the perimeters of skim pits and evaporation ponds and looked for birds and other wildlife. They recovered live and dead birds. Bird carcasses were tagged with evidence tags and transferred to USFWS law enforcement agents. The inspectors also recorded the presence of exposed oil on facility grounds, the amount of freeboard present in skim pits and evaporation ponds, and measures implemented to eliminate "imminent and substantial endangerment" to the environment, in particular, birds and other wildlife.

Operation of Commercial and Centralized Facilities

Almost half (14) of the 28 COWDFs inspected in Wyoming had one evaporation pond, and the remainder had two to nine evaporation ponds (Table 1). Twenty of the 28 COWDFs used sprayers on the evaporation ponds to enhance evaporation (Table 1). Thirteen (46%) of the COWDFs used earthen skim pits to separate oil from the wastewater (Table 1). All of the 13 COWDFs using skim pits used netting to exclude wildlife; however, the netting was not adequate to exclude birds. Ten of the 13 COWDFs corrected the netting problems, which usually consisted of holes in the netting or the netting sagging into the pit fluids.

Avian and Other Wildlife Mortality

From March 1998 through September 2008, USFWS and EPA facility inspectors documented bird mortality in 9 of the 28 COWDFs in Wyoming. Inspectors documented the mortality of 269 birds which included the following species: eared grebe (*Podiceps nigricollis*); Western grebe (*Aechmophorus occidentalis*); American widgeon (*Anas americana*); mallard (*A. platyrhynchos*); blue-winged teal (*A. discors*); Northern shoveler (*A. clypeata*); canvasback (*Aythya valisineria*); American coot (*Fulica americana*); Wilson's phalarope (*Phalaropus tricolor*); an unidentified gull (*Larus* spp.); Western meadowlark (*Sturnella neglecta*); and various unidentified aquatic birds and passerine songbirds (Table 2). Unlike oilfield production skim pits where passerine birds accounted for over half (62%) of bird remains identified by Trail (2006), aquatic birds comprised 88% of the bird carcasses observed at COWDFs. Grebes (Family Podicipedidae) and puddle ducks (*Anas* spp.) were the most frequently recovered bird species in COWDFs, 28% and 47%, respectively. Typically, the carcasses of larger birds such as ducks and grebes tend to persist longer than the carcasses of smaller passerine birds and thus are easier to detect (Flickinger and Bunck 1987).

Most mortalities were attributed to oil on evaporation ponds because the carcasses were either partially or completely covered with oil. Sodium toxicity and surfactants were the suspected causes of mortality at three COWDFs. Some of the carcasses recovered from these three COWDFs (35 out of 172 carcasses) were submitted for necropsy at the U.S. Geological Survey's National Wildlife Health Center (NWHC) in Madison, Wisconsin and at the Wyoming State Veterinary Laboratory in Laramie, Wyoming. Ten of the 35 bird carcasses had brain sodium concentrations

Table 1 Number of inspections conducted in commercial and centralized oilfield wastewater disposal facilities in Wyoming

Site #	County	# Inspections	1st inspection	Last inspection	# Skim pits	# Evap ponds	Sprayers	# Inspections oil in Evap ponds	% Inspections with oil in Evap pond	# Inspections sheen on Evap pond	% Inspections with sheen on Evap pond
1	Campbell	34	31-Mar-98	9-Sep-08	2	2	No	25	74	30	88
2	Campbell	1	9-Sep-08	9-Sep-08	1	0	No	na	na	na	na
3	Carbon	2	4-Jun-07	29-Aug-08	0	3	Yes	1	50	0	0
4	Carbon	2	4-Jun-07	21-Aug-07	2	9	Yes	1	50	0	0
5	Converse	15	31-Mar-98	8-Sep-08	1	1	No	11	73	0	0
6	Converse	16	31-Mar-98	8-Sep-08	2	1	No	5	31	7	44
7	Fremont	1	12-Sep-06	12-Sep-06	0	1	Yes	0	0	0	0
8	Fremont	2	21-Aug-07	8-Aug-08	3	1	No	1	50	0	0
9	Fremont	1	21-Aug-08	21-Aug-08	1	1	Yes	0	0	0	0
10	Johnson	5	30-Mar-98	9-Sep-08	1	1	Yes	1	25	1	25
11	Johnson	13	5-Nov-01	9-Sep-08	2	1	No	5	38	0	0
12	Sublette	8	22-Sep-98	19-Aug-08	0	1	Yes	6	75	0	0
13	Sublette	3	22-Sep-98	5-Jun-07	1	2	Yes	0	0	0	0
14	Sublette	2	26-Aug-04	5-Jun-07	0	5	Yes	2	100	0	0
15	Sublette	2	26-Aug-04	5-Jun-07	0	6	Yes	0	0	0	0
16	Sublette	5	14-Jul-05	19-Aug-08	0	1	Yes	4	80	1	25
17	Sweetwater	1	25-Jun-08	25-Jun-08	0	1	Yes	0	0	0	0
18	Sweetwater	2	3-Jul-02	29-Aug-02	0	1	Yes	0	0	0	0
19	Sweetwater	7	9-Nov-04	18-Aug-08	0	2	Yes	0	0	0	0
20	Sweetwater	3	26-Sep-05	18-Aug-08	0	3	No	0	0	0	0
21	Sweetwater	1	24-Jun-08	24-Jun-08	0	2	Yes	1	100	0	0
22	Sweetwater	1	24-Jun-08	24-Jun-08	0	1	Yes	0	0	0	0
23	Sweetwater	2	2-May-00	24-Jun-08	1	2	Yes	0	0	0	0
24	Sweetwater	2	25-Jun-08	19-Aug-08	0	2	No	2	100	2	100
25	Uinta	8	21-Sep-98	19-Aug-08	1	2	Yes	6	75	0	0
26	Uinta	2	12-Sep-06	4-Jun-07	0	1	Yes	2	100	2	100
27	Uinta	2	25-Jun-08	19-Aug-08	1	2	Yes	2	100	2	100
28	Washakie	11	18-Jun-02	21-Aug-08	0	1	Yes	4	36	7	63
	Totals	154					20	79	51	52	34

Na not applicable

Table 2 Number of bird carcasses observed at commercial and centralized oilfield wastewater disposal facilities in Wyoming

	Site #[a]									Totals	Percent
	1	5	6	11	12	16	19	24	28		
Eared Grebes	7	0	5	0	1	0	0	0	0	13	5
Grebe spp.	40	1	2	0	3	0	6	0	2	54	20
Pied-billed grebe	0	0	0	0	0	0	0	0	0	0	0
Western Grebe	1	0	5	0	0	0	0	0	0	6	2
Puddle Duck	0	0	0	0	0	0	97	30	0	127	47
Diving Duck	0	0	3	0	0	0	1	0	0	4	1
Duck spp.	3	0	4	1	0	0	11	0	0	19	7
Canada Goose	0	0	0	0	0	0	0	0	0	0	0
Am. Coot	0	0	2	0	0	0	4	0	0	6	2
Songbird	4	1	7	1	0	0	0	0	0	13	5
Gull spp.	0	0	0	0	0	0	1	0	0	1	0
Phalarope	0	0	0	0	0	0	1	0	0	1	0
Bird spp.	1	2	2	4	4	12	0	0	0	25	9
Totals	56	4	30	6	8	12	121	30	2	269	
Grebes	48	1	12	0	4	3	6		2	76	28
Waterfowl	3	0	9	1	0	2	109	30	0	154	57
Aquatic birds	0	0	2	0	0	0	6	0	0	8	3
Total	51	1	23	1	4	5	121	30	2	238	88

[a] No mortalities observed at Sites 2–4, 7–10, 13–15, 17, 18, 20–23, and 25–27

ranging from 2,270 to 3,920 µg/g wet weight. Brain sodium concentrations greater than 2,000 µg/g wet weight are diagnostic of sodium poisoning (Meteyer and others 1997). Brain sodium concentrations in the remaining 25 bird carcasses ranged from 4,710 to 30,823 µg/g wet weight, these extremely high concentrations may be due to contamination of the tissue during dissection or post-mortem absorption of sodium (Meteyer and others 1997). Necropsy reports on five carcasses described the plumage as "thoroughly wet to the skin" which suggests that these birds may have come into contact with surfactants present in the wastewater.

Grebes accounted for 86% of the mortality in one facility in Campbell County, Wyoming. Teal (*Anas* spp.) accounted for 72% of the mortality in a centralized facility in Carbon County, Wyoming. During the 9-year period, 49 live birds were observed on evaporation ponds at the 28 COWDFs of which 17 were captured. Attempts were made to transport live oil-covered birds to licensed bird rehabilitators for cleaning, recovery and release into the wild. Other wildlife mortality observed at COWDFs included jackrabbits (*Lepus* spp.); cottontails (*Sylvilagus* spp.); tiger salamanders (*Ambystoma tigrinum*); and numerous insects.

Bird mortalities in these COWDFs appear to be episodic; there may be long periods without incident, but then a large number of birds may be killed during short periods, such as migration. Grover (1983) and Esmoil (1995, personal communications) documented episodic mortality events in oil pits. Grover (1983) found that in southeastern New Mexico, wildlife losses in oil pits during the summer consisted of inexperienced, recently fledged or weaned wildlife. During the fall, waterfowl and shorebirds were the primary victims of oil pits. Esmoil (1995, personal communications) found a disproportionate number of loggerhead shrikes killed during a 2-week period that coincided with fledging. During one COWDF inspection in September 12, 1994, Service personnel recovered 22 aquatic birds from a COWDF evaporation pond in Converse County, Wyoming.

Actual bird mortality in COWDFs is probably higher than the total observed as single inspections reveal only a fraction of the annual bird mortality in oil pits or ponds (Trail 2006). Flickinger and Bunck (1987) recommended weekly pit inspections to adequately document bird mortality. Bird and other wildlife mortalities in oil pits and oil-covered evaporation ponds can go undetected as scavengers can remove carcasses. Bird carcasses can also sink into the pits or ponds in a matter of a few days (Flickinger and Bunck 1987). Depending on the size of the carcass, the ambient temperature and the temperature of the oil and wastewater, the carcass can disintegrate and not be readily detected (Flickinger and Bunck 1987). Flickinger and Bunck (1987) reported that wind action and rainfall could influence "how rapidly carcasses become saturated with oil or sink." Higher ambient temperatures and hot oil temperatures can accelerate carcass tissue breakdown and oil penetration into the carcass, thus causing the carcasses to sink into the oil layer (Flickinger and Bunck 1987).

Environmental Compliance Issues

Typical compliance problems involved exposed oil on the surface of skim pits; oil, emulsified oil, and sheens on evaporation ponds; and oil on the banks of evaporation ponds. These problems were primarily due to inadequate facility design and operations and maintenance. Some COWDFs did not have oil–water separation tanks or pits and the oilfield wastewater was directly discharged into the evaporation pond. In these COWDFs, the prevailing Westerly winds were relied on to push the oil to the leeward side of the evaporation pond where the oil was boomed off and periodically removed with vacuum trucks.

Most COWDFs did not have physical barriers to prevent vacuum truck access to the evaporation ponds; thus facilitating the direct discharge of oilfield wastewater from the vacuum trucks into the COWDF evaporation ponds. In COWDFs with only one oil–water separation tank or pit, off-loading the wastewater agitated the contents in the receiving separation tank or pit and thus compromised the oil–water separation layers. The remixing of the oil and water resulted in the discharge of oil from the separator tank or pit into the evaporation pond.

Failure to quickly remove oil from the COWDF evaporation ponds resulted in the oil coating and saturating the shoreline and pond berms in evaporation ponds without synthetic liners. The oil-soaked berms provide a chronic source of oil and sheens into the evaporation pond when high ambient temperatures cause the oil to seep from the berm back into the pond. Additionally, precipitation can wash oil from the berm back into the evaporation pond.

Wyoming state regulations require at least 61 centimeters (cm) (2 feet) of freeboard in separation skim pits and evaporation ponds. Inadequate freeboard was documented in 3 COWDFs, primarily because the operators accepted too much wastewater.

Corrective Measures Implemented

Corrective action typically consisted of removing oil from evaporation ponds; installing effective wildlife exclusionary devices (usually netting) at oil skim pits; replacement of nets sagging into separation pit fluids; and removal of puddled oil adjacent to storage tanks. One facility installed a radar-activated bird deterrent system. Another facility covered its 5-acre evaporation pond with high density polyethylene (HDPE) "bird balls," hollow plastic balls intended to cover the entire surface of the pond making it unattractive to aquatic birds. No bird mortality has been documented following the deployment of the HDPE bird balls. However, high winds at this facility blow a significant number of balls off the pond creating a chronic maintenance problem to keep the pond completely covered. Some COWDFs improved the oil–water separation system by increasing the number of separation tanks to prevent oil discharges into the evaporation ponds. Physical barriers, such as fencing and gates were installed in some COWDFs to prevent vacuum truck drivers from off-loading wastewater directly into the evaporation ponds.

We did not document any mortality in pits with adequate and properly maintained netting. Large bird mortality incidents have not occurred in the COWDF with the radar-activated bird deterrent system; however, the risk of mortality has not been fully eliminated. Ronconi and others (2004) reviewed the efficacy of radar-activated bird deterrent systems and reported a reduction in the number of bird landings.

Management Recommendations

Deep well injection of oil field wastewater would eliminate the need for evaporation ponds and thus eliminate the risk to birds and other wildlife from exposed oil, surfactants and hypersaline conditions that could result in mortality. Where deep well injection is not feasible and evaporation ponds for water disposal will be part of a proposed facility, it should include controls to prevent the discharge of wastewater containing oil and surfactants into evaporation ponds. The State of New Mexico, for example, requires "trap devices" to prevent solids and oil from being transferred from one pond to another (New Mexico Administrative Code 19.15.36.17). Contingency plans should be developed at COWDFs to ensure immediate clean up of oil discharged into evaporation ponds to prevent wildlife mortalities.

COWDFs should also be designed with features to prevent wastewater transportation trucks from off-loading directly into the evaporation ponds. Such features could consist of physical barriers to prevent unauthorized access to the evaporation ponds and signs directing truck drivers to the designated off-loading site.

If open-topped tanks or pits will be used to store and separate oil from wastewater, effective wildlife exclusionary devices should be installed to prevent wildlife mortality. Flagging is not an effective deterrent (Esmoil and Anderson 1995). Netting is the most effective method of keeping birds from entering wastewater evaporation ponds and oil production skim pits. Netting of large evaporation ponds (>0.4 ha or 1 acre) is generally not feasible from an engineering and economic standpoint.

Key facility personnel should undergo annual training to provide them with a refresher on permit requirements, health and safety issues and emergency spill procedures. Such training would help to ensure that COWDFs are properly operated and managed, thus lowering the risk to birds and other wildlife.

Site security is paramount in ensuring proper operation of COWDFs and minimizing risks to birds and other wildlife. Controlling access either with locked gates or onsite personnel will prevent unauthorized discharge of hazardous wastes into the facility. Adequate bonding is necessary to ensure proper closure and cleanup of the COWDFs if the facility is abandoned by the operator.

Summary

Although the oil industry and state and federal regulators have made much progress in reducing bird mortality in oil and gas production facilities, significant mortality incidents continue in COWDFs, particularly older facilities permitted in the early 1980's. Inadequate operation and management of these COWDFs generally results in the discharge of oil into the large evaporation ponds which then poses a mortality risk to birds and other wildlife.

Intensive efforts should be made to ensure that COWDFs are managed properly and the risk to birds and wildlife is eliminated. Research and development of cost-effective treatment and reuse of wastewater may produce long-term solutions that may eliminate the current environmental risks from oil, salts, and surfactants in COWDF evaporation ponds.

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Exhibit 30.09

This exhibit was not previously submitted in November 2023

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PROFILE

Avian Mortality at Oil Pits in the United States: A Review of the Problem and Efforts for Its Solution

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Abstract Oil production operations produce waste fluids that may be stored in pits, open tanks, and other sites accessible to wildlife. Birds visit these fluid-filled pits and tanks (“oil pits”), which often resemble water sources, and may become trapped and die. The US Fish and Wildlife Service (USFWS) has a program to reduce these impacts by locating problem pits, documenting mortality of protected wildlife species, and seeking cleanup or corrective action at problem pits with the help of state and federal agencies regulating the oil industry. Species identification and verification of protected status for birds recovered from oil pits are performed at the USFWS National Fish and Wildlife Forensics Laboratory. From 1992 to 2005, a minimum of 2060 individual birds were identified from remains recovered from oil pits, representing 172 species from 44 families. The taxonomic and ecological diversity of these birds indicates that oil pits pose a threat to virtually all species of birds that encounter them. Ninety-two percent of identified bird remains belonged to protected species. Most remains identified at the Forensics Laboratory were from passerines, particularly ground-foraging species. Based on Forensics Laboratory and USFWS field data, oil pits currently cause the deaths of 500,000–1 million birds per year. Although law enforcement and industry efforts have produced genuine progress on this issue, oil pits remain a significant source of mortality for birds in the United States.

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Introduction

Petroleum production is accompanied by the production of waste fluids. These fluids (often referred to in the oil industry as “E&P waste,” for exploration and production waste) are a mixture of water with a variety of contaminants, commonly including drilling muds, concentrated salts, hydrocarbons that were not removed in the separation process, and trace amounts of potentially toxic metals (EPA 2000, 2002). In many oil production areas, these waste fluids are a major source of environmental pollution and public health concern (e.g., San Sebastián and Hurtig 2004).

Exposure to petroleum waste fluids may also be a significant source of wildlife mortality. In the United States, there are more than 500,000 oils wells currently active (IPAA 2005). When the produced waste fluids are stored in exposed pits or open-topped tanks (hereafter, oil pits), they pose a potential hazard to wildlife. Many U.S. oil production areas are located in arid regions where open water is scarce, increasing the attractiveness of oil pits both to waterbirds that land in the fluid, and to terrestrial birds and other wildlife that come to drink. Wildlife may also be attracted by food items that are trapped on the margins and surface of oil pits (Flickinger 1981; Grover 1983; Flickinger and Bunck 1987).

Beginning in the 1950s, numerous studies have documented significant wildlife mortality in oil pits:

914 dead waterfowl in Wyoming (King 1956); 585 vertebrates in Colorado (Tully and Boulter 1970); more than 1600 birds and mammals in California (Thomas 1971); 469 birds in New Mexico (Grover 1983); 394 birds in coastal Texas (Flickinger 1981); and 616 birds in Wyoming (Esmoil and Anderson 1995). Birds are by far the predominant vertebrate remains recovered from oil pits (Grover 1983), and are the focus of this report. Documentation of reptile and mammal mortality in oil pits can be found in Grover (1983), Flickinger (1981), Thomas (1971), Tully and Boulter (1970), and Wood and Harrod (2000).

Causes of Mortality in Oil Pits

Exposure to oil causes avian mortality in a variety of ways (Leighton 1993). Waterbirds that alight in oil pits may drown or die of exposure after the loss of feather insulation due to oiling (King 1956; Flickinger and Bunck 1987). Birds that are trapped in viscous oil pit fluids may ingest lethal amounts of oil in their struggles to escape, or die of exposure or starvation (Grover 1983). Although this article concerns only direct mortality at oil pit sites, exposure to toxic fluids in pits likely causes additional mortality away from pits (Hartung and Hunt 1966; Snyder and others 1973), as well as reproductive impairment in birds that survive (Grau and others 1977; Albers 1978; King and LeFever 1979).

Oil Pits and U.S. Environmental Laws

Most waste fluids commonly stored in oil pits (E&P wastes) are exempt from federal regulation as hazardous wastes (EPA 2000). Still, the operators of facilities with oil pits in the United States are subject to regulation under federal wildlife protection and environmental pollution laws (Judah 1997; USFWS 1998). The most comprehensive wildlife law that may be triggered by avian mortality in oil pits is the Migratory Bird Treaty Act (MBTA), which prohibits the killing (or "taking") of native North American migratory birds. Examples of oil production activities that could result in "take" are discharges of oil or hazardous materials, and operation of oil pits that are accessible to wildlife. Other laws that may be violated by avian mortality in oil pits include the Endangered Species Act (ESA), Bald and Golden Eagle Protection Act, and, for non-migratory upland game birds (Galliformes), state wildlife management laws.

Enforcement of the MBTA is the responsibility of the Office of Law Enforcement of U.S. Fish and Wildlife Service (USFWS). Violations of the MBTA carry penalties up to a $15,000 fine, or 6 months in jail, or both, for each count (i.e., each dead bird of a protected species). There is no "allowable take" under the MBTA, and, because it is a strict liability statute, the government is not required to prove that an oil producer knew that exposed waste fluids were taking migratory birds. Although the MBTA provides for fines and other penalties, it does not give USFWS the power to compel pit owners to clean up problem sites or to render them inaccessible to wildlife.

The Environmental Protection Agency (EPA) is responsible for enforcement of pollution statutes that apply to oil pits, including the Clean Water Act, the Resource Conservation and Recovery Act (RCRA), and the Oil Pollution Act of 1990 (EPA 2000). These statutes empower EPA to alleviate threats to the environment or human health caused by waste management operations, and allow for substantial fines for violations. Section 7003 of RCRA is triggered if EPA determines that either solid or hazardous waste is present in a pit, and that the site poses an actual or potential threat to human health and/or the environment (USFWS 1998). Documented avian mortality demonstrates such an actual environmental threat. RCRA requires the violator to complete an EPA-approved workplan to correct the violations, and to do the necessary work in the field. If these requirements are not met, EPA can impose penalties of $6,500 per day. EPA's authority to require clean-up of oil pits makes it a vital partner with USFWS in rendering these sites safe for both human health and wildlife.

Law Enforcement Related to Wildlife Mortality in Oil Pits

Concerted law enforcement activities aimed at reducing wildlife mortality in U.S. oil pits began in the late 1970s, primarily in New Mexico and Texas (Grover 1983; Lee 1990). Much mortality was prevented as a result; for example, Grover (1983) estimated that 225,000 birds a year were saved from oil pits due to oil pit clean-ups on Bureau of Land Management lands in New Mexico. An early success was the elimination in 1978 of the practice of pumping waste fluids into dry lake basins (playas) in Texas, accomplished through negotiations between USFWS, the U.S. Department of Justice, and Texas state officials (Lee 1990). USFWS has continued oil pit enforcement activities in Texas, Oklahoma, and New Mexico since that time, in collaboration with state agencies. These efforts have produced considerable progress. For example, from 1999 to 2002 USFWS issued letters of noncompliance concerning more than 1800 oil pits and tanks in this three-state area, and collected more than $194,000 in fines due to Migratory Bird Treat Act violations (USFWS 2002). These funds were all deposited in the North American Wetlands Conservation Fund, as required by law.

In 1996, the Oil and Gas Environmental Assessment (OGEA) team was formed in the northern Great Plains and Rocky Mountain area, including the states of North and South Dakota, Montana, Wyoming, Colorado, and Utah (EPA 2003). The team was made up of representatives from USFWS, EPA, the state oil and gas agencies, the state environmental agencies, tribal energy and environmental agencies, the Bureau of Land Management, and the Bureau of Indian Affairs. By 2002, the OGEA team had coordinated aerial surveys of approximately 5000 pits (15–20% of the total in the region), had conducted the ground inspection of 475 potential problem sites, and had completed 365 follow-up actions that corrected the problem identified (EPA 2003).

In addition to these major coordinated efforts, USFWS has carried out local oil pit inspection and enforcement activities in virtually all oil-producing areas of the United States since the 1990's (e.g., Wood and Harrod 2000). These efforts are ongoing.

Collection of Avian Remains from Oil Pits

Exposed oil pits that appear likely to pose a hazard to wildlife were located by enforcement personnel of USFWS and cooperating agencies through aerial and/or ground-based surveys (USFWS 1998; Wood and Harrod 2000; EPA 2003). These "problem oil pits" were then visited and inspection was made for wildlife remains. Bird remains visible on the surface and margins of oil pits were recovered and tagged. No attempt was made to dredge ponds for remains that might have sunk out of sight into the pit fluids. Most oil pit inspections were made during the spring and summer months, and most pits were visited only once.

Analysis and Identification of Remains

The determination that oiled bird remains belong to protected species is prerequisite to enforcement action by USFWS. Non-native birds, notably rock pigeon (*Columba livia*), European starling (*Sturnus vulgaris*), and house sparrow (*Passer domesticus*), are not protected, and their death in oil pits does not trigger U.S. federal or state wildlife laws. Successful law enforcement also requires that bird remains recovered from oil pits be treated as evidence, with strict chain-of-custody procedures and analytical protocols for species identification.

Since 1992, species identification of oiled bird remains has been conducted at the USFWS National Fish and Wildlife Forensics Laboratory. The laboratory's evidence-handling and analytical procedures meet the strict forensic standards of the American Society of Crime Lab Directors (ASCLD). Upon receipt at the laboratory, each set of remains was assigned a tracking number in the computerized laboratory evidence inventory system, linked to the "seizure tags" filled out at the time of collection by USFWS field personnel. The items remained under seal in the Evidence Unit freezers until they were transferred to the laboratory's ornithologist for analysis and identification.

Examination and cleaning were carried out under a fume hood, using chemical safety precautions. Remains ranged from oil-covered but otherwise intact carcasses to single bones or feathers. The most usual remains were decayed partial carcasses, with heads and tails often missing. The surrounding matrix varied from brine with little obvious oil to solid blocks of tar. Oiled remains sometimes exhibited sufficient species-diagnostic characters that they could be identified without cleaning. In that case, notes were taken documenting the diagnostic features observed (e.g., plumage pattern), and a confirmatory reference standard from the laboratory's bird specimen collection was cited. Usually, however, cleaning of remains was required for identification.

Before cleaning began, characteristics were noted indicating the order or family to which the bird remains belonged. These included body size and shape, and the morphology of the beak and feet, if visible. This preliminary evaluation was the basis for selecting parts for cleaning. For example, if the remains resembled a dove, a tail feather was removed, whereas if the remains resembled a duck, a secondary (speculum) feather was selected, because those are distinctive feathers for their respective groups.

The selected item was wiped to remove excess oil, and was then placed in a bath of Stoddards Solvent (petroleum distillate; Fisher Scientific). In most cases, this solvent dissolved the oil residue and rendered the plumage pattern visible. It was sometimes necessary to gently brush the feather with a soft toothbrush to loosen solid clumps of oil.

Once the oil residue was removed, the item was washed in a bath of hot water and detergent. Feathers typically emerged from this process with little physical damage, although the concentrated brine found in some pits could destroy feather structure. Exposure to oil commonly produced discoloration of feather vanes, imparting a yellowish tinge to white areas, but this usually did not complicate identification. When the cleaning was complete, the object was dried with compressed air and was then ready for comparison with specimen standards.

The Forensics Laboratory maintains a reference collection of bird specimens, including prepared skins, skeletons, and loose feathers. This collection includes more than 6000 specimens and more than 950 bird species. Species identification was made by detailed comparison of cleaned feathers and/or bones with known specimen standards. In addition to specimens, reference works were consulted during the examination process, including Pyle (1997) and relevant species accounts in the American Ornithologists' Union *Birds of North America* series. The authority for avian taxonomy was the A.O.U. Checklist of North American Birds (American Ornithologists Union 2005).

For each set of remains examined, the ornithologist prepared laboratory bench notes documenting the observed species-diagnostic characters and the specimen reference standards consulted. The cleaned remains were documented with digital photography. Examination and documentation procedures were performed in accordance with ASCLD-approved Forensic Laboratory protocols.

After identification, a forensic report was written for the USFWS Special Agent in charge of the investigation. This stated the identity of the bird remains and, if multiple remains of a given species were recovered from a single pit, the minimum number of individuals (MNI) present. MNI was calculated based on duplicated elements recovered from the same pit, such as skulls or left wings. MNI was used to determine the number of wildlife law violations.

Patterns of Avian Mortality in Oil Pits

From August 1992 to June 2005 (the period covered by this report), a minimum of 2060 individual bird remains were recovered from oil pits and identified by USFWS personnel. One hundred sixty-two of the remains belonged to non-native bird species. All the rest (1898, or 92% of the total) belonged to native species protected under the MBTA or managed under state game laws. These remains represented 172 bird species from 16 orders and 44 families (Table 1). Most of these species (154, or 90%) were identified at the National Fish and Wildlife Forensics Laboratory; the remainder was identified by other federal and state personnel.

Birds were recovered and identified from oil pits in 21 states, stretching from Ohio to California (Table 1). Three states—Texas, Oklahoma, and Kansas—accounted for more than 50% of the birds identified from oil pits at the Forensics Lab (Table 2). The wide disparity between states reflects both differing numbers of oil production facilities and differing intensity of oil pit enforcement efforts.

The threat posed by oil pits was not limited to particular taxonomic or ecological categories of birds. Among the victims of oil pits were birds as large as bald eagle (*Haliaeetus leucocephalus*) and as small as kinglets (*Regulus* species); as insectivorous as yellow-billed cuckoo (*Coccyzus americanus*), as frugivorous as cedar waxwing (*Bombycilla cedrorum*), and as granivorous as pyrrhuloxia (*Cardinalis sinuatus*); as aerial as chimney swift (*Chaetura pelagica*) and as terrestrial as greater roadrunner (*Geococcyx californianus*); as dependent on forests as red-eyed vireo (*Vireo olivaceus*) and on deserts as cactus wren (*Campylorhynchus brunneicapillus*). It appears that oil pits pose a hazard to virtually every bird species that encounters them.

Information on the outcomes of encounters with oil pits by birds is limited to opportunistic observations (Flickinger 1981; Grover 1983); no systematic, quantitative studies have been made. Such documentation would be needed to assess vulnerability to this hazard among different ecological categories and species of birds. Nevertheless, analyses of the identifications made at the Forensics Lab reveal some broad patterns. Remains of songbirds and related species (Passeriformes) were the most common (62%) of all birds recovered from oil pits (Table 3). The next most frequently encountered group, the waterfowl (Anseriformes), accounted for only 10% of remains. Passerines were represented by 22 different families (Table 4). The Emberizidae (sparrows and allies) and Icteridae (blackbirds and allies) accounted for more than 50% of passerine bird remains recovered (and one third of all bird remains).

In terms of broad ecological categories, the most frequent victims of oil pits were ground-feeding birds, accounting for 63% of all remains (Figure 1). Ecological categories were defined as follows: <u>Waterbirds</u> = Podicipediformes + Pelecaniformes + Anseriformes; <u>Wading Birds</u> = Ciconiiformes (except Cathartidae) + Charadriiformes + Gruiformes + Alcedinidae; <u>Birds of Prey</u> = Falconiformes + Strigiformes + Cathartidae; <u>Ground Feeders</u> = Galliformes + Columbiformes + *Geococcyx* + *Colaptes* + Alaudidae + Motacillidae + Passeridae + Icteridae (except *Icterus*) + Emberizidae +

Table 1 Bird taxa identified from remains recovered from oil pits

Order Family Species	MNI	States
Podicipediformes (n = 25)		
Podicipedidae (n = 25)		
Pied-billed grebe, *Podilymbus podiceps*	7	MI, IL, NM, TX
Eared grebe, *Podiceps nigricollis*	12	WY
Eared or Horned grebe (*P. nigricollis* or *P. auritus*)	5	WY
Unidentified grebe (Podicipedidae)	1	KS
Pelicaniformes (n = 3)		
Phalacrocoracidae (n = 3)		
Double-crested cormorant, *Phalacrocorax auritus*	3	TX
Ciconiiformes (total = 86)		
Ardeidae (total = 78)		
American bittern, *Botaurus lentiginosus*	1	NE
Great blue heron, *Ardea herodias*	59	MI, IL, KY, AL, AR, NE, KS, TX, CO, NM, WY, UT, CA
Great egret, *Ardea alba*	3	TX
Reddish egret, *Egretta rufescens*	1	TX
Snowy egret, *Egretta thula*[a]	n/a	NM
Tricolored heron, *Egretta tricolor*[b]	n/a	TX
Little blue heron, *Egretta caerulea*	1	AR
Cattle egret, *Bubulcus ibis*	3	KS, TX
Unidentified egret (Ardeidae)	1	TX
Green heron, *Butorides virescens*	4	IL, IN, AR
Black-crowned night-heron, *Nycticorax nycticorax*	4	AL, TX, NM, CA
Yellow-crowned night-heron, *Nyctanassa violacea*	1	TX
Cathartidae (total = 8)		
Turkey vulture, *Cathartes aura*	7	OK, TX
Black vulture, *Coragyps atratus*	1	TX
Anseriformes (total = 213)		
Anatidae (total = 213)		
Black-bellied whistling-duck, *Dendrocygna autumnalis*	5	TX
Fulvous whistling-duck, *Dendrocygna bicolor*	1	TX
Greater white-fronted goose, *Anser albifrons*	1	NE
Canada goose, *Branta canadensis*	1	OH
Snow goose, *Chen caerulescens*[a]	n/a	NM
Wood duck, *Aix sponsa*	19	OH, IN, KY, AR, NE, KS, TX
Gadwall, *Anas strepera*	20	IL, MO, KS, OK, TX, CO, WY, UT, NM
American wigeon, *Anas americana*	5	OK, TX, WY, NM
Mallard, *Anas platyrhynchos*	13	OH, IL, KS, TX, WY, NM
Mottled duck, *Anas fulvigula*[b]	n/a	TX
Blue-winged teal, *Anas discors*	37	IN, NE, KS, TX, CO, WY
Cinammon teal, *Anas cyanoptera*[a]	n/a	NM
Unspecified teal (*A. discors* or *A. cyanoptera*)	5	CO, UT
Northern shoveler, *Anas clypeata*	25	OK, TX, CO, NM, UT
Northern pintail, *Anas acuta*	4	OK, TX, CO
Green-winged teal, *Anas crecca*	25	KS, OK, TX, NM, CO, WY, UT
Unspecified dabbling duck (*Anas* species)	19	OH, IL, MI, TX, KS, NM, CO, WY
Redhead, *Aythya americana*[c,d]	n/a	OK, TX
Ring-necked duck, *Aythya collaris*	6	TX, CO
Greater scaup, *Aythya marila*	1	IL
Lesser scaup, *Aythya affinis*	11	MI, IL, TX, NM, CO
Unspecified scaup (*Aythya* species)	4	IL, KS, CO
Canvasback or redhead (*Aythya vasilineria* or *A. americana*)	2	OK
Bufflehead, *Bucephala albeola*	1	MI
Common merganser, *Mergus merganser*	1	CO
Hooded merganser, *Lophodytes cucullatus*	1	CO
Ruddy duck, *Oxyura jamaicensis*	3	TX, NM
Unidentified waterfowl (Anatidae)	3	WY

Table 1 Continued.

Order Family Species	MNI	States
Falconiformes (total = 48)		
Accipitridae (total = 28)		
Mississippi kite, *Ictinia mississippiensis*[a]	n/a	NM
Bald eagle, *Haliaeetus leucocephalus*	1	CA
Northern harrier, *Circus cyaneus*	1	WY
Harris' hawk, *Parabuteo unicinctus*	1	TX
Sharp-shinned hawk, *Accipiter striatus*	1	TX
Cooper's hawk, *Accipiter cooperii*	3	KS, OK, NM
Unspecified accipiter (*Accipiter* species)	2	TX
Swainson's hawk, *Buteo swainsoni*	3	KS, OK
Red-tailed hawk, *Buteo jamaicensis*	16	MI, IL, MO, KS, OK, TX, NM, CO
Golden eagle, *Aquila chrysaetos*[a]	n/a	NM
Falconidae (total = 20)		
American kestrel, *Falco sparverius*	18	IN, NE, KS, OK, TX, NM, CA
Peregrine falcon, *Falco peregrinus*[c]	n/a	TX
Prairie falcon, *Falco mexicanus*	2	OK, CO
Galliformes (total = 39)		
Phasianidae (total = 5)		
Ring-necked pheasant, *Phasianus colchicus*	4	NE, OK, TX, UT
Lesser prairie-chicken, *Tympanuchus pallidicinctus*[a]	n/a	NM
Helmeted guineafowl, *Numida meleagris*	1	OK
Odontophoridae (total = 34)		
Scaled quail, *Callipepla squamata*	2	OK, NM
Gambel's quail, *Callipepla gambelii*	3	TX
Northern bobwhite, *Colinus virginianus*	17	IL, KS, OK, TX
Unidentified quail (Odontophoridae)	12	TX, NM
Gruiformes (total = 9)		
Rallidae (total = 9)		
Virginia rail, *Rallus limicola*	1	IL
Sora, *Porzana carolina*	1	UT
Unidentified rail (Rallidae)	1	CA
Common moorhen, *Gallinula chloropus*[c]	n/a	TX
American coot, *Fulica americana*	6	IL, MO, OK, TX, NM
Charadriiformes (total = 55)		
Charadriidae (total = 15)		
Killdeer, *Charadrius vociferus*	15	MI, IL, IN, KS, TX, NM
Recurvirostridae (total = 4)		
American avocet, *Recurvirostra americana*	4	TX, CO, UT
Scolopacidae (total = 22)		
Lesser yellowlegs, *Tringa flavipes*	2	NE, NM
Solitary sandpiper, *Tringa solitaria*	2	KS, NM
Spotted sandpiper, *Actitis macularia*	1	SD
Least sandpiper, *Calidris minutilla*[d]	n/a	OK
Unspecified "peep" sandpiper (*Calidris* species)	1	KS
Long-billed dowitcher, *Limnodromus scolopaceus*	1	NE
Wilson's snipe, *Gallinago delicata*	8	NE, KS, TX, CO, WY, UT
American woodcock, *Scolopax minor*	4	OH, KY, IL, KS
Unidentified sandpiper (Scolopacidae)	3	NE, WY
Laridae (total = 14)		
Laughing gull, *Larus atricilla*	1	TX
Herring gull, *Larus argentatus*	2	AL
Ring-billed gull, *Larus delawarensis*	2	OH, OK
Unspecified gull (*Larus* species)	8	MI, CO
Black skimmer, *Rynchops niger*	1	TX
Columbiformes (total = 117)		
Columbidae (total = 117)		
Rock pigeon, *Columba livia*	38	OH, MI, IN, IL, MO, KS, OK, TX, NM, CA
Mourning dove, *Zenaida macroura*	78	OH, IL, MO, NE, KS, OK, TX, CO, NM, CA
Unidentified dove (Columbidae)	1	OH

Table 1 Continued.

Order Family Species	MNI	States
Cuculiformes (total = 38)		
Cuculidae (total = 38)		
Yellow-billed cuckoo, *Coccyzus americanus*	6	KY, KS, TX
Greater roadrunner, *Geococcyx californianus*	32	OK, TX, NM
Strigiformes (total = 106)		
Tytonidae (total = 54)		
Barn owl, *Tyto alba*	54	NE, KS, OK,TX, NM, CA
Strigidae (total = 52)		
Eastern screech-owl, *Megascops asio*	9	KY, IL, KS, TX
Western screech-owl, *Megascops kennicottii*[d]	n/a	NM
Unspecified screech-owl (*Megascops* species)	3	TX, NM
Great horned owl, *Bubo virginianus*	31	KY, NE, KS, OK, TX, MT, CO
Barred owl, *Strix varia*	5	KY, AR, KS, OK, TX
Short-eared owl, *Asio flammeus*	1	KS
Burrowing owl, *Athene cunicularia*	3	TX, NM, CA
Caprimulgiformes (total = 24)		
Caprimulgidae (total = 24)		
Lesser nighthawk, *Chordeiles acutipennis*	1	TX
Common nighthawk, *Chordeiles minor*	18	OH, IL, MO, TX, NM
Unspecified nighthawk (*Chordeiles* species)	3	TX, NM
Whip-poor-will, *Caprimulgus vociferus*	1	IL
Common poorwill, *Phalaenoptilus nuttallii*	1	CA
Apodiformes (total = 4)		
Apodidae (total = 4)		
Chimney swift, *Chaetura pelagica*	4	NE, TX
Coraciiformes (total = 2)		
Alcedinidae (total = 2)		
Belted kingfisher, *Ceryle alcyon*	2	IL, TX
Piciformes (total = 13)		
Picidae (total = 13)		
Red-bellied woodpecker, *Melanerpes carolinus*[c]	n/a	TX
Golden-fronted woodpecker, *Melanerpes aurifrons*	3	TX
Unspecified woodpecker (*Melanerpes* species)	3	IL, TX
Northern flicker, *Colaptes auratus*	7	NE, KS, TX, UT
Passeriformes (total = 1278)		
Tyrannidae (total = 67)		
Eastern phoebe, *Sayornis phoebe*	13	OH, IN, IL, KS, OK, TX
Say's phoebe, *Sayornis saya*[a]	n/a	NM
Ash-throated flycatcher, *Myiarchus cinerascens*[a]	n/a	NM
Great Crested flycatcher, *Myiarchus crinitus*	1	TX
Western kingbird, *Tyrannus verticalis*	19	NE, TX, NM
Eastern kingbird, *Tyrannus tyrannus*	10	IL, ND, NE, KS, TX
Scissor-tailed flycatcher, *Tyrannus forficatus*	2	TX
Unspecified kingbird (*Tyrannus* species)	19	OK, TX, NM, CO
Unidentified flycatcher (Tyrannidae)	3	IL, KS, NM
Laniidae (total = 11)		
Loggerhead shrike, *Lanius ludovicianus*	8	KS, OK, TX, NM, CA
Northern shrike, *Lanius excubitor*	2	KS, TX
Unspecified shrike (*Lanius* species)	1	NM
Vireonidae (total = 1)		
Red-eyed vireo, *Vireo olivaceus*	1	IL
Corvidae (total = 15)		
Blue jay, *Cyanocitta cristata*	6	KS
Western scrub-jay, *Aphelocoma californica*	3	NM, CA
Black-billed magpie, *Pica hudsonia*[e]	n/a	CO
American crow, *Corvus brachyrhynchos*	2	KY, TX
Chihuahuan raven, *Corvus cryptoleucus*	1	NM
Unspecified crow (*Corvus* species)	3	AR, OK, TX

Table 1 Continued.

Order Family Species	MNI	States
Alaudidae (total = 31)		
Horned lark, *Eremophila alpestris*	31	IL, NE, OK, TX, MT, WY, CO, NM
Hirundinidae (total = 35)		
Tree swallow, *Tachycineta bicolor*	6	IL, ND, NE, KS
Barn swallow, *Hirundo rustica*	27	IL, KY, KS, OK, TX, WY
No. rough-winged swallow, *Stelgidopteryx serripennis*	1	KS
Unidentified swallow (Hirundinidae)	1	WY
Paridae (total = 3)		
Juniper titmouse, *Baeolophus griseus*	2	NM
Carolina chickadee, *Poecile carolinensis*	1	KY
Sittidae (total = 1)		
White-breasted nuthatch, *Sitta carolinensis*	1	OK
Troglodytidae (total = 5)		
Cactus wren, *Campylorhynchus brunneicapillus*	2	TX, NM
Carolina wren, *Thryothorus ludovicianus*	1	OK
Bewick's wren, *Thryomanes bewickii*	1	TX
Rock wren, *Salpinctes obsoletus*	1	KS
Regulidae (total = 1)		
Unspecified kinglet (*Regulus* species)	1	MI
Sylviidae (total = n/a)		
Unspecified gnatcatcher (*Polioptila* species)[c]	n/a	TX
Turdidae (total = 14)		
Eastern bluebird, *Sialia sialis*	3	OH, TX, KS
Unspecified bluebird (*Sialia* species)	1	NM
American robin, *Turdus migratorius*	10	IL, NE, KS
Mimidae (total = 131)		
Gray catbird, *Dumetella carolinensis*	2	NE, KS
Northern mockingbird, *Mimus polyglottos*	94	AL, KS, OK, TX, NM
Sage thrasher, *Oreoscoptes montanus*	25	WY, UT
Brown thrasher, *Toxostoma rufum*	6	IN, KS
Curve-billed thrasher, *Toxostoma curvirostre*	1	TX
Unidentified thrasher (Mimidae)	3	TX, NM
Sturnidae (total = 42)		
European starling, *Sturnus vulgaris*	42	MI, IN, IL, NE, KS, OK, CO, CA
Motacillidae (total = 1)		
American pipit, *Anthus rubescens*	1	CA
Bombycillidae (total = 1)		
Cedar waxwing, *Bombycilla cedrorum*	1	OK
Parulidae (total = 7)		
Yellow warbler, *Dendroica petechia*	1	KS
MacGillivray's warbler, *Oporornis tolmiei*	1	CA
Common yellowthroat, *Geothlypis trichas*	1	KS
Yellow-breasted chat, *Icteria virens*	4	KY, CA
Emberizidae (total = 328)		
Canyon towhee, *Pipilo fuscus*	1	TX
Cassin's sparrow, *Aimophila cassinii*	6	OK, TX, NM
Unspecified sparrow (*Spizella* species)	27	ND, TX, WY, NM
Tree sparrow, *Spizella arborea*	1	KS
Vesper sparrow, *Pooecetes gramineus*	13	ND, NE, TX, NM, WY
Lark sparrow, *Chondestes grammacus*	11	KS, OK, TX, NM
Black-throated sparrow, *Amphispiza bilineata*	10	TX, NM
Lark bunting, *Calamospiza melanocorys*	140	NE, KS, OK, TX, CO, NM, WY
Savannah sparrow, *Passerculus sandwicensis*	11	OH, LA, ND, NE, KS, TX
Grasshopper sparrow, *Ammodramus savannarum*	2	OK
Song sparrow, *Melospiza melodia*	21	OH, MI, IN, IL, KS, TX, CO, CA
Swamp sparrow, *Melospiza georgiana*	1	IN
Unspecified sparrow (*Zonotrichia* species)	2	NE
White-crowned sparrow, *Zonotrichia leucophrys*	2	OK, CA
Dark-eyed junco, *Junco hyemalis*	2	KS, TX

Table 1 Continued.

Order Family Species	MNI	States
Lapland longspur, *Calcarius lapponicus*	3	OK, MT
McCown's longspur, *Calcarius mccownii*[a]	n/a	NM
Smith's longspur, *Calcarius pictus*[a]	n/a	NM
Chestnut-collared longspur, *Calcarius ornatus*	1	KS
Unidentified sparrow (Emberizidae)	74	OH,IL,KY, NE, KS, OK, TX, WY, CO, NM
Cardinalidae (total = 58)		
Northern cardinal, *Cardinalis cardinalis*	17	KS, OK, TX
Pyrrhuloxia, *Cardinalis sinuatus*	35	TX, NM
Unspecified bunting (*Passerina* species)	1	IN
Black-headed grosbeak, *Pheucticus melanocephalus*	2	NM
Dickcissel, *Spiza americana*	3	TX
Icteridae (total = 352)		
Red-winged blackbird, *Agelaius phoeniceus*	44	IL, NE, KS, OK, TX, CO, WY
Unspecified blackbird (*Agelaius* species)	6	CA
Unspecified meadowlark (*Sturnella* species)	179	ND, SD, NE, KS, OK, TX, WY, CO, NM
Yellow-headed blackbird, *X. xanthocephalus*	2	NE, KS
Rusty blackbird, *Euphagus carolinus*	2	IL, ND
Brewer's blackbird, *Euphagus cyanocephalus*	4	CO
Unspecified blackbird (*Euphagus* species)	4	TX
Common grackle, *Quicalus quiscula*	42	IN, KY, IL, MO, ND, NE, KS, OK, TX, NM
Great-tailed grackle, *Quiscalus mexicanus*	2	NE, OK
Unspecified grackle (*Quiscalus* species)	4	TX
Brown-headed cowbird, *Molothrus ater*	39	ND, NE, KS, OK, TX, CO
Unspecified cowbird (*Molothrus* species)	2	OK, TX
Bullock's oriole, *Icterus bullockii*	1	NM
"Northern oriole," *Icterus galbula* or *I. bullockii*	1	NM
Orchard oriole, *Icterus spurius*	1	TX
Unspecified oriole (*Icterus* species)	16	KS, TX, NM
Unidentified blackbird (Icteridae)	3	KS, NM, CA
Fringillidae (total = 22)		
Unspecified rosy-finch (*Leucosticte* species)	7	WY
House finch, *Carpodacus mexicanus*	8	NM, CA
Unspecified finch (*Carpodacus* species)	3	IL
American goldfinch, *Carduelis tristis*	4	IL, KS
Passeridae (total = 77)		
House sparrow, *Passer domesticus*	77	IN, IL, ND, NE, KS, OK, TX, CO, CA
Unidentified passerines (not consistent with *Sturnus* or *Passer*) (total = 75)		
Grand total = 2060		

Identifications were made by staff at the National Fish and Wildlife Forensics Laboratory, unless noted by a superscript. Total = 172 unique taxa (species and taxa that were never identified below the genus level; e.g. meadowlarks, *Sturnella* sp.). MNI = minimum number of individuals in oil pit remains analyzed at the National Fish and Wildlife Forensics Laboratory, 1992–2005. n/a = MNI data not available (analyses not carried out at the Forensics Laboratory)

Data sources for bird taxa identified by authorities other than the National Fish and Wildlife Forensics Laboratory

[a] Grover, V. L. 1983. The reduction of wildlife mortality in the sump pits of southeast New Mexico. Report for the Bureau of Land Management, Carlsbad, New Mexico

[b] Flickinger, E. L. 1981. Wildlife mortality at petroleum pits in Texas. *Journal of Wildlife Management* 45:560–564

[c] Lee, R. C. Jr. 1994. Migratory bird kills at petroleum pits in Texas. Report of Investigation No. 120, U.S. Dept. of Interior, U.S. Fish and Wildlife Service, Division of Law Enforcement, Lubbock, Texas

[d] McKay, T. 2002. Environmental contaminants program, off-refuge investigations sub-activity. FY 2002 final report. TX, OK, NM — oilfield pollution. Project ID: 2F37,9920006.2. U.S. Dept. of Interior, U.S. Fish and Wildlife Service, Division of Law Enforcement, Oklahoma City, Oklahoma

[e] Ramirez, P. Jr., and G. G. Mowad. Personal communication

Table 2 Oiled bird remains identified at the National Fish and Wildlife Forensics Laboratory, summarized by state

State	MNI
Alabama	10
Arkansas	10
California	60
Colorado	114
Illinois	123
Indiana	32
Kansas	285
Kentucky	18
Louisiana	1
Michigan	34
Missouri	12
Montana	12
Nebraska	62
New Mexico	159
Ohio	35
Oklahoma	432
North Dakota	19
South Dakota	26
Texas	432
Utah	15
Wyoming	169
Total	2060

MNI = minimum number of individual birds

Table 3 Oiled bird remains identified at the National Fish and Wildlife Forensics Laboratory, summarized by avian order

Order	MNI	Percent
Podicipediformes	25	1.2%
Pelecaniformes	3	0.1%
Ciconiiformes	86	4.2%
Anseriformes	212	10.3%
Falconiformes	46	2.2%
Galliformes	39	1.9%
Gruiformes	9	0.4%
Charadriiformes	55	2.7%
Columbiformes	117	5.7%
Cuculiformes	38	1.8%
Strigiformes	106	5.1%
Caprimulgiformes	24	1.2%
Apodiformes	4	0.2%
Coraciiformes	2	0.1%
Piciformes	13	0.6%
Passeriformes	1278	62.0%
Total	2060	

MNI = minimum number of individual birds

Cardinalidae (except *Pheucticus*) + Fringillidae + Corvidae + Laniidae + Mimidae + Turdidae + Sturnidae; Arboreal Feeders = *Coccyzus* + *Melanerpes* + Bombycillidae + Parulidae + Regulidae + Paridae + Sittidae + Troglodytidae + Vireonidae + *Icterus* + *Pheucticus*; and Aerial Feeders = Caprimulgiformes + Apodiformes + Tyrannidae + Hirundinidae. The total number of identified remains in Figure 1 is 1985 (2060 remains identified to protected category minus 75 passerines that were not identified at the family level).

Table 4 Oiled passerine remains identified at the National Fish and Wildlife Forensics Laboratory, summarized by family

Family	MNI	Percent
Alaudidae	31	2.4%
Bombycillidae	1	< 0.1%
Cardinalidae	58	4.5 %
Corvidae	15	1.2%
Emberizidae	328	25.7%
Fringillidae	22	1.7%
Hirundinidae	35	2.7%
Icteridae	352	27.5%
Laniidae	11	0.9%
Mimidae	131	10.3%
Motacillidae	1	< 0.1%
Paridae	3	0.2%
Parulidae	7	0.5%
Passeridae	77	6.0%
Sylviidae	n/a	n/a
Regulidae	1	< 0.1%
Sittidae	1	< 0.1%
Sturnidae	42	3.3%
Troglodytidae	5	0.4%
Turdidae	14	1.1%
Tyrannidae	67	5.2%
Vireonidae	1	< 0.1%
Unknown	75	5.9%
Total	1278	

MNI = minimum number of individual birds

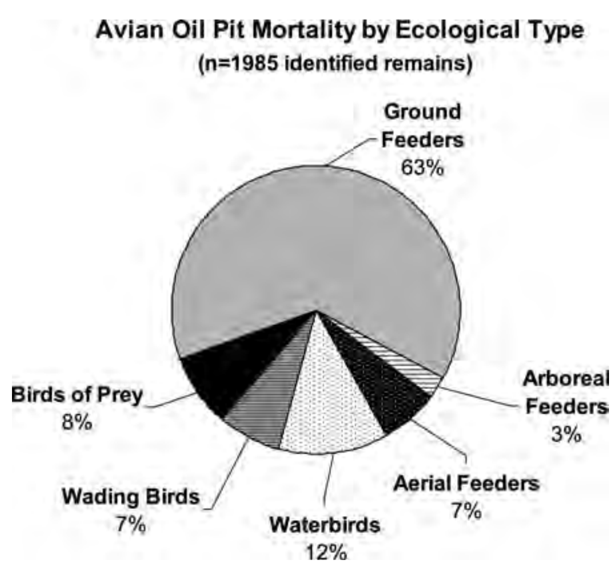

Fig. 1 Oil pit mortality by general ecological category, for the bird remains identified at least to the family level at the forensics lab (n = 1985 remains). See text for description of taxa included in each ecological category. Sample sizes as follows: waterbirds = 241 remains; wading birds = 144 remains; birds of prey = 162 remains; ground feeders = 1256 remains; arboreal feeders = 52 remains; and aerial feeders = 130 remains

Four of the top five species recovered from oil pits were ground-feeding passerines, namely, meadowlark (*Sturnella* species), lark bunting (*Calamospiza melanocephala*), northern mockingbird (*Mimus polyglottos*), and house sparrow (*Passer domesticus*); the fifth was the ground-feeding mourning dove (*Zenaida macroura*). The majority of inspected oil pits were located in open, semiarid habitats with few trees (USFWS field staff, personal communication). This likely contributed to the low numbers of arboreal birds recovered from oil pits (Figure 1).

Birds dependent on water for foraging (waterbirds and wading birds) made up a small proportion (19%) of all avian oil pit mortalities (Figure 1). Indeed, the proportion of waterbirds recovered from oil pits appears to be decreasing. Between 1992 and 1996, water and wading birds comprised 27% of the oiled bird remains identified at the Forensics Lab. From 1998 to 2005, they comprised only 14% (no oil pit remains were identified at the laboratory in 1997 due to staff turnover). This trend may reflect continuing success in reducing the size of oil pits.

Avian mortality increases linearly with oil pit surface area (Esmoil and Anderson 1995). Large, lake-like oil pits formerly attracted large numbers of ducks (Gregory and Edwards 1991), but the use of such sites has now been largely eliminated (Lee 1990). The typical oil pit today is a far smaller, pool-like site. Surveys of oil pits in Texas in the early 1980s yielded average pit sizes of 1208 m^2 in coastal areas and 372 m^2 in northwestern Texas (Flickinger and Bunck 1987). In contrast, 19 storage sites inspected in west Texas from 1999–2002 ranged from 0.56 to 372 m^2, with a mean of 45.6 m^2 (USFWS 2002). These smaller pits appear to draw fewer waterfowl, but still attract passerines and other nonaquatic birds.

Prior Estimates of Avian Mortality in Oil Pits

Several regional and national estimates of direct avian mortality in oil pits have been made. Grover (1983) estimated an annual mortality of 450,000 vertebrates at oil pits in southeastern New Mexico from the 1950s to 1981, when a cleanup effort was launched. Birds represented more than 90% of this mortality, based on identified remains. Lee (1990:444) stated that annual bird mortality from oil pits in Oklahoma, Texas, and New Mexico ‘‘easily exceeded 300,000 birds, including 100,000 ducks’’ in the late 1980s. Banks (1979:12) extrapolated from a 1970s annual mortality estimate of 150,000 in California's San Joaquin valley to make a ‘‘very conservative’’ estimate of 1.5 million birds killed in oil pits nationwide each year.

For many years, USFWS estimated bird mortality in oil pits at approximately 2 million per year (e.g., Ramirez 1999). Due to progress that has been made on the oil pit problem through enforcement activities and industry compliance, that estimate is no longer considered valid (EPA 2003). Given that enforcement activities continue to document avian mortality at oil pits, it is important to estimate the current extent of the problem.

Estimating Current Annual Avian Mortality in Oil Pits

Earlier nationwide estimates of avian oil pit mortality were based on extrapolations of data from specific areas, without discussion of underlying assumptions. This article presents a more explicit process of estimation, which may spur efforts to address the data gaps that remain.

There appear to be no published data on the number of oil pits in the United States. Most drilling sites have at least one pit for storage of waste fluids, including produced water and drilling muds, and some wells have multiple pits for different E&P wastes (EPA 2000, 2002). Therefore, I assumed that each of the nation's approximately 500,000 onshore oil wells had one associated oil pit.

These calculations further assume that 80% of the nation's oil pits pose no threat to wildlife. This value is based on data from aerial surveys in the northern Great Plains and Rocky Mountains (EPA 2003). This produces an estimate of approximately 100,000 pits deserving of inspection nationwide (0.20 × 500,000 wells producing oil). The average rate of avian mortality at inspected pits from 1996 to 2002 across a broad area of the western United States was 0.30 birds/inspection (Table 5). Therefore, it is expected that 30,000 dead birds would be recovered if all questionable oil pits were subjected to a one-time inspection (100,000 pits × 0.3 birds/pit).

Single inspections reveal only a small fraction of the annual avian mortality in an oil pit. Many oiled bird remains are removed by scavengers, and others sink out of sight over time (Grover 1983). In a study of Texas oil pits, Flickinger and Bunck (1987) determined that the average sinking time for passerines in the warmer months was only 4 days. They recommended that pits be inspected at least once a week to document all passerine mortality in summer, with inspections at least every 3 weeks in winter.

Based on these studies, I propose that the following inspection schedule would be needed to document

Table 5 Results of two recent oil pit inspection efforts by the Fish and Wildlife Service and Environmental Protection Agency[a]

Locality	No. pits inspected	Pits with avian mortality	No. of bird mortalities
Colorado	96	20	89
Montana	169	9	47
North Dakota	56	3	7
South Dakota	16	8	38
Utah	115	2	2
Wyoming	347	33	137
Kansas	360	74	183
Nebraska	74	32	140
Subtotals	1233	181 (14.6%)	643
So. New Mexico	280	16	150
Oklahoma	1374	31	81
Texas	537	48	151
Subtotals	2191	95 (4.3%)	382
Grand Totals	3424	276	1025

[a] Data from northern Great Plains and Rocky Mountain states from EPA (2003); data from Oklahoma, Texas, and New Mexico from USFWS (2002)

most avian mortality in oil pits: one inspection per month from November to February; two inspections per month in March, April, September, and October; and four inspections per month in May, June, July, and August. This totals 28 inspections per year. The most northern states might need no inspections at all from November through February or March, but the southern states might need even more than indicated on this schedule.

One-time inspections of all questionable oil pits in the United States would yield the remains of approximately 30,000 birds, as calculated above. Thus, a full schedule of 28 inspections per year is predicted to yield a total annual mortality of approximately 840,000 birds (30,000 birds $\times$ 28 needed inspections). The toll among protected birds is estimated at 772, 800 per year, given Forensics Lab data that 92% of oiled bird remains belong to protected species.

Clearly, this is a rough calculation. Still, it provides grounds for concluding that the current annual mortality at oil pits is in the range of 500,000–1 million birds. That is a considerable decline from the former mortality estimate of 2 million birds per year, made prior to concerted enforcement efforts. This is an encouraging indication that enforcement and proactive industry compliance have indeed reduced avian mortality in oil pits in the United States. Nevertheless, even the lower-end estimate of 500,000 birds is a very high annual toll for a human-caused, preventable source of mortality on U.S. native birds. It compares, for example, to an estimate of 250,000 birds killed as a result of the *Exxon Valdez* oil spill (Piatt and Ford 1996), which is generally considered to be one of the greatest environmental disasters of recent times.

Protecting Wildlife from Oil Pits

The goal of USFWS and cooperating agencies is to render oil production waste fluids inaccessible to wildlife and humans, and to isolate them from groundwater supplies. The best permanent solution is the replacement of oil pits with closed tanks or other closed containment systems. When properly designed and installed, such systems require little or no maintenance and eliminate the possibility of soil contamination (USFWS 2003).

If open pits are retained, they need to be enclosed with netting to exclude wildlife. Deterrent methods, including flagging, strobe lights, reflectors, and noisemakers, do not reduce avian mortality in oil pits (Esmoil and Anderson 1995). Sturdy, well-installed netting is highly effective at excluding birds. Such netting should be supported by a steel frame and provide complete enclosure. Netting requires maintenance and monitoring to assure that it remains effective under all conditions. For example, weakly supported netting may sag into oil pits under the weight of snow, destroying its ability to exclude wildlife. Detailed information on effective netting solutions, with photographs, can be found at the website for the Environmental Contaminants Program of Region 6 of the Fish and Wildlife Service (USFWS 2003).

Through a combination of law enforcement, education, and cooperation with industry, progress continues to be made in eliminating oil pits that threaten wildlife. Still, further efforts are needed. The level of noncompliance to wildlife protection and environmental pollution laws remains too high. Further work by both government agencies and the oil industry is needed to eliminate this significant, preventable, and illegal source of avian mortality in the United States.

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