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Environmental and Community Impacts of Shale Development in Texas

The Academy of Medicine, Engineering and Science of Texas (TAMEST)

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THE ACADEMY OF MEDICINE, ENGINEERING AND SCIENCE OF TEXAS
Austin, TX

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This report was initiated and administered by The Academy of Medicine, Engineering and Science of Texas (TAMEST), which is a nonprofit and brain trust for Texas composed of the Texas-based members of the National Academies of Sciences, Engineering, and Medicine, and the state's Nobel Laureates. TAMEST convenes influential experts to promote cross-industry and cross-disciplinary research and knowledge sharing, and serves as an intellectual resource for the state. TAMEST brings the state's top scientific, academic, and corporate minds together to further position Texas as a national research leader.

TASK FORCE ON ENVIRONMENTAL AND COMMUNITY IMPACTS OF SHALE DEVELOPMENT IN TEXAS

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Preface

Hydraulic fracturing and horizontal drilling technologies applied multiple times in long horizontal wells has led to an ability to profitably produce vast shale gas and tight oil resources. By adapting these enabling technologies developed and proven in Texas, the late George P. Mitchell led the economic development of shale energy resources. The abundant oil and gas supplies unleashed by shale development have generally led to lower cost electricity, heating, and gasoline for U.S. consumers. In addition to George Mitchell's innovations, many other entities and individuals played important roles in promoting shale energy technologies and processes. The U.S. Department of Energy and the Gas Technology Institute (formerly the Gas Research Institute), for example, were critical partners in technology development for shale resources starting in the 1970s. These technologies have allowed Texas to lead the nation in oil and natural gas production and for the United States to be one of the world's leaders in oil and natural gas production.

A 2008 report from the National Academies, entitled *America's Energy Future,* offered a very different landscape from what we see today. The following quote is taken from the preface of that report: "Nearly 60 percent of the U.S. demand for oil now is met by depending on imports supplied by foreign sources, up from 40 percent in 1990." Similarly, the 2007 National Petroleum Council (NPC) report, titled *Facing the Hard Truths about Energy*, said the following:

> Conventional oil is forecast to contribute the largest share of global liquid supply, principally through increased production in Saudi Arabia, Russia, Venezuela, Iran, and Iraq. Unconventional oil such as Canadian and Venezuelan heavy oil and the U.S. oil shale is also likely to play a growing role in the liquids supply mix. However, most forecasts project that unconventional oil, together with coal-to-liquids (CTL) and gas-to-liquids (GTL), is unlikely to exceed 10 million barrels per day globally by 2030.

Without the technology and resource development in Texas, U.S. energy security would be even more threatened than it was at the time these reports were released. Instead, less than seven years later, U.S. companies began to export both natural gas and crude oil, and were largely responsible for reducing the world oil price by a half.

In fact, U.S. shale production since these reports were published just ten short years ago has surpassed almost everyone's projections. Scott Sheffield, retired CEO of Pioneer Natural Resources, when speaking at Columbia University in April 2017, stated, "I think [oil production] will be well over 10 million barrels a day at some point in time in 2018, and that is primarily due to the growth of the Permian [basin]."

The Academy of Medicine, Engineering and Science of Texas (TAMEST) was founded starting from an original idea of Senator Kay Bailey Hutchison in 2004. In 2015, the TAMEST board agreed to a proposal to organize a task force charged with writing this report. TAMEST staff and I then recruited and appointed the task force members. A portion of the funding for the report project was provided generously by The Cynthia and George Mitchell Foundation, and we thank the foundation's Vice President of Sustainability Programs, Marilu Hastings, for her interest in and support of our project. A first-of-its-kind in the state of Texas, this report mimics at a state level processes used to prepare scholarly, peer-reviewed reports published by the National Academies of Sciences, Engineering, and Medicine.

As chair of the TAMEST Shale Task Force that prepared this report, it was my pleasure and privilege to work with this knowledgeable and experienced team. The group felt strongly about the need to produce a consensus report that would be broadly distributed to citizens of Texas and provide science-based information to inform their perspectives on shale energy resources. Our report audience includes Texas legislators, elected officials, and decision makers at all levels. We hope that other U.S. states and nations around the world that are in the midst of debate and discussion about shale resources likewise will find it informative and useful.

Christine Ehlig-Economides, Task Force Chair, University of Houston

Acknowledgments

This report was reviewed in draft form by individuals chosen for their diverse perspectives and technical expertise, in accordance with procedures approved by The Academy of Medicine, Engineering and Science of Texas (TAMEST).

The purpose of this independent review was to provide candid and critical comments that would assist TAMEST in making its published report as sound as possible and to ensure the report met organizational standards for objectivity, evidence, and responsiveness to the study charge. The review comments and draft manuscript remain confidential to protect the integrity of the deliberative process.

We wish to thank the following individuals for their review of this report:

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Although reviewers provided many constructive comments and suggestions, they were not asked to endorse conclusions or recommendations, nor did they see the final draft of the report before its release.

The review of this report was overseen by TAMEST board member Kenneth Arnold of K Arnold Consulting, Inc. Appointed by TAMEST, Mr. Arnold was responsible for ensuring that an independent examination of this report was carried out in accordance with institutional procedures and that all review comments were carefully considered. Responsibility for the final content of this report rests entirely with TAMEST and the task force.

Summary

By many measures, including annual revenues and number of employees, the oil and gas industry is one of the world's largest business sectors. It includes not only U.S.-based firms, but also major energy corporations based in China, the Netherlands, the United Kingdom, and many other nations. Major changes in the oil and gas industry have substantive implications for and effects upon all other business and commercial sectors, both in the United States and around the world.

The biggest change in the global oil and gas industry during the past decade has been the proliferation of horizontal drilling and multi-stage hydraulic fracturing. Improvements in many aspects of the technologies and materials used in the horizontal drilling and hydraulic fracturing processes have opened up vast shale deposits that previously were not viable economically for oil and gas production.

A significant portion of this major energy development and technological breakthrough since the mid-2000s has taken place in Texas. Today, Texas produces more crude oil than any other state, and is responsible for more than one-third of the nation's total oil production (EIA, 2017a). Texas oil production in 2015 was larger than that of all but six countries (EIA, 2017b).

Texas has long been a major producer of domestic oil and gas supplies and products. Texas remains a leading United States oil and gas producer and, in fact, the state today is on par with many of the world's major energy-producing nations. These changes in the Texas oil and gas sector have important implications not only for Texas, but also for the entire United States as well as other parts of the world. These new technologies have opened access to vast new supplies of natural gas that in many areas are partly displacing coal for power generation.

The development of shale and related hydrocarbon resources continues to expand. At the same time, there is opposition to this expansion in many places, including some U.S. states, such as New York, and some nations, such as France. However, hydraulic fracturing for shale development will continue to be an important and likely growing part of the Texas and United States energy production portfolio. A better understanding of the many implications and effects of shale development will help identify research priorities that, in turn, will support improved management of many different risks and environmental mitigation activities. One theme common to several chapters in this report is a call for easier and wider access to data from shale development operations to all interested parties.

The Academy of Medicine, Engineering and Science of Texas (TAMEST) convened a task force to prepare this report on the Texas shale development experience. This report covers the underlying science for six topic areas as it pertains to shale exploration and production activities: 1) geology and earthquake activity; 2) land resources; 3) air quality; 4) water quantity and quality; 5) transportation; and 6) economic and social impacts.

There is a need and opportunity to improve the broad understanding and awareness of the impacts of shale production. This study aims to help all Texans better understand what is and is not known about the impacts of shale oil and gas development in Texas, and offer recommendations for future research priorities.

Beyond this report's explicit six topic areas, in its deliberations the task force noted there are numerous transdisciplinary connections across these six topic areas. For a variety of reasons, these connections generally have not been evaluated systematically. A better integration and evaluation of factors that cross multiple subject matter areas would provide a more comprehensive understanding of shale development activities, and its implications for Texas communities and biophysical, economic, and social systems.

Furthermore, time and spatial scales regarding the dynamics of geophysical systems, ecosystems, public entities (such as schools and health care facilities) and investments in road construction and maintenance vary considerably. A more sophisticated analytical approach to integrating across these topic areas, and to developing policies and investments accordingly, requires better understanding and appreciation of these different scales and processes.

This summary presents findings and recommendations, in bold-faced print, from the six topic areas addressed in this project, followed by findings and a recommendation regarding transdisciplinary connections and trade-off decisions among the six topic areas. These findings and recommendations are also presented within and at the end of each chapter.

GEOLOGY AND EARTHQUAKE ACTIVITY

The scientific knowledge base of Texas geology and earthquake activity is extensive. Research in this broad scientific field dates back over 100 years, and data collection and studies have been led by experts in the state's numerous large universities, private industry, and some nongovernmental groups. Considering that body of research and knowledge as a collective whole, and attempting to issue broad statements regarding its general adequacy in helping understand a given topic, is a daunting task.

One reason simply is the size of Texas. It is the nation's second-largest state; only Alaska covers more territory. For a frame of reference, its areal extent of 268,580 square miles makes it larger than the Colorado River Basin of the Southwestern United States, which covers large portions of seven U.S. states. The systematic and sustained collection of subsurface data across an area of this size, and the geologic heterogeneity that exists across Texas, represents a considerable challenge and undertaking. A great deal of scientific information has been collected and analyzed, and there have been many advances in this knowledge. Further studies will be necessary to develop a more detailed and sophisticated understanding of these large and complex systems.

The geology of Texas is highly complex, which inhibits clear understanding of the many geological faults across the state and their dynamics. There are significant differences across the state in the composition of the underlying geologic formations, strata, and subsurface geophysical processes. Texas' geology also is unique. It is interesting to note that in comparison to Oklahoma, for example, seismicity in Texas is substantially different. The ratio of the number of magnitude M3.0 earthquakes between Oklahoma and Texas is approximately 60 to 1. The historical record of seismicity in Texas is based on written records and sparse, sometimes limited, instrumental data. Available data indicates increased rates of seismicity in a limited geographic area over the last several years.

As specified in the language of Texas House Bill 2 of 2015, a program—referred to as TexNet—was initiated to provide additional resources to enhance geophysical monitoring across the state. Overseen by multiple universities in the state, research currently being conducted using TexNet funds is focused on understanding the potential relationships between subsurface injection of fluids related to oil and gas production and earthquakes in the vicinity of faults. Chapter 3 provides additional details on the TexNet initiative. These narrow, yet highly complex research goals cannot be accomplished without also performing more fundamental research tasks. In response to increased rates of seismicity in some areas, the Railroad Commission (RRC) of Texas has amended rules to address seismicity in oil and gas regions.

There is ongoing, vigorous research collaboration among academia, industry, and state regulatory agencies. Parties and initiatives include The University of Texas at Austin Bureau of Economic Geology Center for Induced Seismicity Research (CISR); the $4.7 million TexNet seismic monitoring program that includes collaborators from universities, federal and state governments, and industry; and States First, an induced seismicity workgroup initiative that is a multi-state and multi-agency collaborative effort. Improved understanding of potentially-induced seismicity will require these types of long-term, sustained, cross-disciplinary research efforts.

Findings

- **Geologic faults are ubiquitous across Texas; these faults are poorly and incompletely characterized.**
- **The majority of known faults in the subsurface in Texas are stable and are not prone to generating earthquakes.**
- **There has been an increase in the rate of recorded seismicity in Texas over the last several years. Between 1975 and 2008 there were, on average, one to two earthquakes per year of magnitude greater than M3.0. Between 2008 and 2016, the rate increased to about 12 to 15 earthquakes per year on average.**
- **Under certain unique geologic conditions, faults that are at or near critical stress may slip and produce an earthquake if nearby fluid injection alters the effective subsurface stresses acting on a fault.**
- **Mechanisms of both natural and induced earthquakes in Texas are not completely understood, and building physically-complete models to study them requires the integration of data that always will have irreducible uncertainties.**
- **To date, potentially induced earthquakes in Texas, felt at the surface, have been associated with fluid disposal in Class II disposal wells, not with the hydraulic fracturing process.**
- **The TexNet goals address an integrated research portfolio that considers seismicity analysis, geologic characterization, fluid-flow modeling, and geomechanical analysis.**

Recommendations

- **Future geologic and seismological research initiatives should develop improved and transparent approaches that seek to balance concerns surrounding data handling and sharing, and that promote sharing of data.**
- **Development of a common data platform and standardized data formats could enable various entities collecting data to contribute to better data integration. It also could facilitate interdisciplinary collaboration directed toward mitigation and avoidance of induced seismicity.**

LAND RESOURCES

Energy resource development and extraction activities date back many decades in Texas. The majority of land in Texas is privately held, and research of potential impacts on land and ecosystem resources has been limited due to access constraints associated with private land ownership. Some of the more thorough studies have focused on species that were considered for listing as threatened or endangered under the federal Endangered Species Act. Among other things, this limited knowledge base makes it difficult for Texas scientists to identify a baseline of land and ecosystem conditions, and trends by which current and future impacts might be measured.

Below are findings and recommendations to help expand the scientific information available to evaluate how Texas' land resources are affected by shale development. This information will be useful to the oil and gas industry and the state, and will inform efforts designed to increase operational efficiency and minimize environmental impacts. It also will provide more complete and credible data that the general public may use to understand the impacts of shale development on ecosystems and the Texas landscape.

Findings

- **Texas hosts an extraordinary degree of biodiversity, due to the diverse topographic, geologic, and climatic conditions across the state.**
- **Texas lands are almost entirely privately-owned. Shale development takes place largely on private lands, which generally are not sites of formal environmental impact studies.**
- **The few studies that have been conducted on erosion and soil contamination from oil and gas development in Texas indicate that well pad development has an increased potential for erosion, and that soil contamination is possible from oil and gas production.**
- **The vast number of new wells drilled in shale formations in Texas since 2007 have had substantial spatial impacts on the landscape. However, horizontal wells have a smaller impact than the equivalent number of vertical wells would have had. When operators use a single well pad for multiple wells, surface impacts are significantly reduced.**
- **The most comprehensive information on species-specific impacts has been compiled for the Dunes Sagebrush Lizard and Lesser Prairie Chicken, with extensive studies of changes to their habitats and their life cycles and requirements. Both species are covered by voluntary conservation plans overseen by state agencies.**
- **Landowners in Texas who do not own the mineral rights associated with their property have very limited control over oil and gas operations.**
- **Most states where development of shale resources is occurring have a surface damage act in place to protect the rights of landowners who do not own the mineral rights associated with their property. In Texas, if the surface owner controls any portion of the mineral rights, the owner may be able to use contractual provisions to negotiate with the operator and resolve disputes. In addition, if the owner discovers damages caused by the operator within the statute of limitations time frame—two years—the tort/legal system may provide relief. Damages for the landowner are capped at the value of the damaged property and do not cover the actual cost of remediation.**
- **Data on environmental impacts of oil and gas development reside in several**

different state and federal agencies, and there is not a single database, readily searchable and available online, that integrates the data across different entities.

Recommendations

With development poised to intensify in the Permian Basin and elsewhere in West Texas due to recent major discoveries there, there is a significant opportunity to better understand large-scale impacts of oil and gas development on the landscape.

- **Baseline land and habitat conditions at the oil and gas play level should be characterized, and changes to wildlife populations and vegetation should be tracked over time where there are opportunities on both private and public lands.**
- **The effectiveness of voluntary programs to conserve at-risk species should be studied, along with options for incentives to conserve at-risk species and reduce effects on land resources by oil and gas development activities.**
- **Advantages and disadvantages of adopting a surface damages act to address the gaps in legal protection for landowners who do not own the minerals associated with their property should be evaluated.**
- **The existing, nonproprietary information about land impacts of shale development that is collected and evaluated by multiple state and federal agencies should be assembled and made available online to the public.**

AIR QUALITY

Emissions from oil and gas operations in Texas roughly scale with oil and gas production rates. As production of oil and gas from shale resources has increased, the importance of emissions associated with these sources also has increased. The impacts of these emissions on human health and welfare are complex and varied, and occur over spatial and temporal scales that range from local impacts over periods of hours, to national and international impacts over periods extending to decades. In addition, there commonly are region-to-region differences in the magnitude and impacts of air emissions, and such regional differences are observed in Texas. A number of recent studies in Texas have improved understanding of the magnitudes and types of emissions associated with oil and gas production from shale resources.

Findings

- **The production of shale resources results in emissions of greenhouse gases, photochemical air pollutants, and air toxics.**
- **Recent federal and state regulations have reduced emissions from multiple types of emission sources.**

- **Emissions in many categories associated with shale resource production are dominated by a small sub-population of high-emitting sources.**
- **Development of inexpensive, robust, reliable, and accurate methods of rapidly finding high-emitting sources has the potential to reduce emissions.**
- **Shale resource development both directly and indirectly impacts air quality. Indirect impacts include reductions in emissions associated with the substitution of natural gas for coal in electricity generation. Comprehensive assessments of both direct and indirect impacts to air quality from the production of shale resources are complex.**

Recommendation

- **There is limited information concerning exposures to air toxics emissions and their corresponding health impacts. Targeted research in this area should be conducted.**

WATER QUANTITY AND QUALITY

Some of the most significant public concerns surrounding the application of hydraulic fracturing operations regards possible effects on both the available supply of water and possible effects on water quality. Millions of gallons of water are used to fracture a single well. Nevertheless, overall water use by hydraulic fracturing is small compared to that used by agriculture or municipalities. The amount of water used for hydraulic fracturing can be important, however, in areas where water use is otherwise low, such as rural energy-producing counties. The impact of water use on supply can be reduced by limiting freshwater use and using brackish groundwater or produced water for hydraulic fracturing.

Hydraulic fracturing is also a potential concern to drinking water supplies. There is little chance of migration of hydrocarbons or brines from producing formations to drinking water aquifers, but near surface and surface spills or leaks may pose the dominant risk of hydraulic fracturing operations to water resources. Increased complexity of surface fluid management, for example by treatment and use/reuse operations, may increase the potential for spills or leaks and therefore the risk to land and water resources.

Findings

- **Water used in hydraulic fracturing processes in Texas represents a small fraction—less than 1 percent—of total water use statewide. In some regions and locales in Texas, however, water used in hydraulic fracturing represents a significantly larger proportion of local water sources.**
- **Use of brackish groundwater and produced water for hydraulic fracturing**

can reduce freshwater use. Increased use of these waters, however, can potentially increase impacts to land and water due to spills and leaks.

- **The depth separation between oil-bearing zones and drinking water-bearing zones in Texas makes direct fracturing into drinking water zones unlikely, and it has not been observed in Texas.**
- **Surface spills and well casing leaks near the surface are the most likely pathways for oil and gas activities to lead to contamination of drinking water sources and environmental damage.**
- **Information on spills and leaks from oil and gas activities in Texas is less accessible and detailed than in some states, potentially limiting the ability to identify sources and root causes.**
- **In Texas, both economics and risk considerations dictate that much of the produced water will continue to be injected in deep wells or used as fracturing fluid to minimize impacts on other water sources.**

Recommendations

Water Availability and Supply

- **Research and testing to enable the use of brackish groundwater and produced waters for hydraulic fracturing should be encouraged.**
- **Recent Railroad Commission of Texas rules to encourage recycling should be tracked, and their effectiveness for promoting increased use of produced water should be evaluated.**
- **Aquifer investigations including pumping tests and chemical analyses should be used to better characterize the productivity and chemical composition of brackish groundwater, and variability of these properties, in oil and gas producing areas.**
- **Further research on the broad life-cycle risks related to water management decisions should be conducted. This research should recognize trade-offs among water use sectors, and provide a basis for balancing increased use of poor-quality waters with freshwater use for new hydraulic fracturing activities.**

Subsurface Contamination by Fracturing or Formation Fluid

- **Direct migration of contaminants from targeted injection zones is highly unlikely to lead to contamination of potential drinking water aquifers. The collection and sharing of pressure data relevant to communication between water-bearing and producing strata—including non-commercial flow zones—or across wells could help identify and avoid potential concerns.**

Spills of Flowback Water, Drilling Fluid, and Formation Water at the Surface

- **Statewide leak and spill reporting requirements for produced water**

should be considered. For all spilled substances, reporting requirements should be improved to aid identification of the primary sources of leaks and appropriate management responses.

- **Texas regulators and industry should continue to develop and apply best management practices relative to well casing design and construction, and surface management of oil and gas operations, to reduce inadvertent release of fluids.**

Wastewater Treatment and/or Disposal

- **Research on techniques for cost-effectively treating produced water, particularly for uses that have minimal quality requirements, such as for hydraulic fracturing, should be continued.**
- **Additional research to evaluate potential negative impacts of any such uses also should be undertaken.**

TRANSPORTATION

Development of the abundant shale resources across Texas via hydraulic fracturing and multi-stage, horizontal drilling has entailed increases in the volumes of equipment and personnel at well sites across the state. Not only have there been considerable increases in truck traffic across the state, other modes of transportation have also experienced a surge in traffic, as evidenced by the significant increase in energy-related activities at transportation facilities such as ports, railroads, and pipelines.

These increased traffic volumes have accelerated the degradation of pavements and roadside infrastructure. The accelerated damage of pavement structures along secondary state highways and local roads has been estimated at $1.5 to $2.0 billion per year. Costs to the trucking industry are also significant. A preliminary evaluation of the cost in the form of additional vehicle damage and lower operating speeds estimated the cost at $1.5 to $3.5 billion per year.

There also have been increases in accidents associated with the increased traffic volumes. Changes in crash rates have been more pronounced for crashes involving trucks and, particularly, for rural crashes that involve trucks. In most cases, as the severity of the injuries resulting from these crashes worsens, the changes in the corresponding number of crashes have been more pronounced. The result has been a higher percentage in the number of fatal, incapacitating, and non-incapacitating injury crashes in energy development regions compared to overall changes for all types of crashes.

The Texas Legislature has allocated funds to address some of the state's most critical transportation system and safety needs. In some cases, counties and local jurisdictions have also been able to make use of a limited amount of funds based on increased tax revenues to address urgent transportation system challenges. For the most part, however, unmet needs far exceed the availability of the existing funds.

Findings

- **Current technologies for oil and gas development and production from shale formations require very large numbers of heavy truckloads.**
- **Most existing roadway and bridge infrastructure in Texas was not designed to carry or accommodate the current large numbers and weights of truckloads.**
- **Traffic increases—especially truck traffic—associated with the development and production of oil and gas from shale formations in Texas have resulted in increases in the frequency and severity of traffic crash incidents.**
- **The level of funding to address the impacts to the transportation infrastructure and traffic safety in the oil and gas industry area is low relative to the magnitude of the impact.**

Recommendations

- **Enhanced efforts and support of the following research programs and strategies will improve preparedness of the state's transportation systems for oil and gas development and production:**
    - **improved availability and quality of data related to ongoing and forecasted drilling activities;**
    - **development of integrated, multimodal transportation infrastructure strategies and solutions; and**
    - **provisions for reliable, sustainable funding for proactively preparing the state's transportation infrastructure for future drilling activities.**

ECONOMIC AND SOCIAL IMPACTS

A small number of relatively recent studies have examined the objective and perceived economic and social impacts of shale oil and gas development in Texas. Clearly, there are numerous knowledge gaps in the economic and social science literatures on shale development.

Findings

- **Shale energy development primarily contributes positively to local, regional, and state economies, but not all economic effects have been positive.**
- **Limited published data exist on the net economic benefits and costs of shale energy development to the institutions and residents in Texas counties and communities.**
- **Public school districts and universities across Texas benefit substantially from the taxes and royalty revenue paid by the oil and gas industry.**
- **Economic benefits associated with oil and gas development are unevenly distributed across public schools and universities.**

- **Community leaders and residents in Texas tend to appreciate and welcome the economic and service-related benefits that accompany shale energy development, whereas they tend to dislike certain social and/or environmental effects that accompany it.**
- **Traffic-related issues—including increased truck traffic, traffic accidents, and traffic congestion—are of primary concern to leaders and residents in and around communities experiencing shale development.**
- **The oil and gas industry is viewed as a relatively trustworthy source for information on shale development and hydraulic fracturing.**
- **The more negatively shale energy development is perceived—particularly with respect to the social and environmental consequences—the more likely local residents are to engage in behaviors opposing increased shale development.**
- **Decisions regarding setback distances in Texas are established at the municipal level.**
- **Shale development has the potential to disproportionately affect certain segments of the population.**

Recommendations

The following items represent areas where knowledge of potential economic and social implications of shale development is severely limited, and should be considered as future research priorities.

- **Additional research on the economic benefits and costs and associated equity issues—or "winners and losers"—in shale energy development is warranted. The broad implications of shale development for local governments and public school districts also should be investigated.**
- **Additional research on the underlying factors accompanying the formation of both positive and negative perceptions of shale development is needed.**
- **Additional research is warranted to provide a more comprehensive understanding of the various factors that may be associated with behavior taken in response to or anticipation of shale development.**
- **Additional research is needed to examine the potential environmental and health effects associated with varying setback distances.**
- **Additional research on the uneven distribution of benefits and costs associated with development is warranted.**

TRANSDISCIPLINARY CONNECTIONS, TRADE-OFFS, AND DECISION MAKING

Most, if not all, future shale development decisions likely will be affected by more than one of the topic areas featured in this report. Although investigation of transdisciplinary linkages was not explicitly part of this project's scope of work, shale investment decisions will be influenced by connections and processes that cross many of the subject matter areas investigated in this report.

Sound shale investment and related decisions will consider not only the individual topics, but also the connections between them, how effects in one area may influence effects in the other areas, and the varying time scales of the relevant processes involved. Those decisions will be strengthened to the extent that they acknowledge and anticipate trade-offs among these areas and related constituent groups, and seek a balance between short-term and long-term benefits and costs of those decisions—including costs and risks that may be more difficult to express in monetary terms. Furthermore, such decisions will be better informed by results from research initiatives that explicitly examine the systemic and interdisciplinary links across biophysical and social sciences fields and phenomena.

Findings

- **Significant connections that lack formal studies exist among the six topic areas discussed in this report.**
- **A common shortcoming expressed in several chapters is the need for access to data and information acquired by various academic, governmental, and industrial entities. This issue is even more apparent for interdisciplinary research efforts.**
- **Disciplinary interconnections often are at the center of major trade-off decisions regarding shale development investments; however, they are difficult to clearly identify and evaluate.**
- **The task force was not aware of any major, prominent initiatives to develop integrated approaches for monitoring, analyzing, and monetizing transdisciplinary implications of Texas shale development.**

Recommendation

- **Connections among the multiple disciplinary areas and trade-off decisions that underpin shale investment decisions should be systematically identified, discussed, and evaluated.**

1

Introduction

For more than a century, the exploration, extraction, processing, and distribution of oil and gas have been of vital importance to the Texas economy, patterns of urban settlement, its transportation networks, and the state's historical and cultural fabric. The oil and gas industry is one of the state's largest employers. It is a major economic driver in several Texas cities, including its largest city, Houston, which is an important business center for most of the world's largest petroleum exploration and production companies.

Oil production began in Texas in 1901 when an Austrian-born engineer named Anthony F. Lucas convinced two Pennsylvania oilmen—John Galey and James Guffey—to finance a drilling operation south of Beaumont. They struck a gusher of oil on January 10. The Spindletop well soon was producing more than 100,000 barrels per day, more than all other wells in the United States combined. Numerous other large oil fields were discovered and developed following Spindletop, and Texas soon was the nation's leading oil-producing state.[1]

Today, Texas produces more crude oil than any other state, and is responsible for more than one-third of the nation's total oil production (EIA, 2017a). Texas oil production in 2015 was larger than that of all but six countries (EIA, 2017b). Dozens of energy companies, including ExxonMobil, Marathon Oil, ConocoPhillips, Valero Energy, Pioneer Natural Resources, and Anadarko Petroleum are headquartered in Texas. These companies support large numbers of jobs in many areas across the state.

One dimension of oil and gas development in Texas has been "boom and bust" cycles that feature periods of tremendous economic activity and wealth generation,

[1] More details of the historical development of the U.S. and global oil industry are included in one of the authoritative books on this topic, Daniel Yergin's "The Prize: The Epic Quest for Oil, Money and Power." Yergin won a Pulitzer Prize in 1992 for this book, which was reissued in 2011. (Yergin, 2011).

followed by periods of economic decline, due to a drop in commodity prices, or depletion of the resource in a given area. The Texas oil and gas industry has gone through multiple cycles of upturns and downturns; for example, in early 2015, oil and gas drilling activity in Texas and the United States experienced a slowdown caused by declining oil and gas prices in early 2015. This downturn in the oil and gas development sector was due largely to surplus oil and gas production resulting from enormous successes of, first shale gas, and then tight oil production. Although the slowdown led to some bankruptcies and the loss of thousands of jobs, the successful technologies remain. Together with an existing enormous resource base, these technologies will create additional reserves with every rise in the global oil price. As such, the downturn is evolving into slow but steady growth in Texas oil and gas development (see Yergin, 2011, for an overview of the global oil and gas industry and many of its economics dimensions and considerations).

This report uses the term "shale" to describe organic rich formations containing natural gas (shale gas) and/or oil (tight oil) that require multiple hydraulic fractures, usually created from long wells drilled horizontally, to produce hydrocarbons profitably (such formations often are not technically what geologists would term shale). The term "tight oil" may include hybrid formations containing oil that has migrated into very tight rock. Many experts refer to shale gas and tight oil resources collectively as "unconventional." This term also can refer to other resources not commonly found in Texas, and thus is not used widely in this report.

With this broad definition of shale resources, the report discusses current oil and gas activity in a variety of areas of Texas, including the Anadarko Basin in the Texas Panhandle region, the Barnett Shale in North Central Texas, the Eagle Ford in South Texas, the Haynesville area of East Texas, and the Permian Basin in West Texas (Figure 1-1). These areas have varying geology, but extensive hydraulic fracturing and horizontal drilling have been used in all these regions to expand oil and gas production.

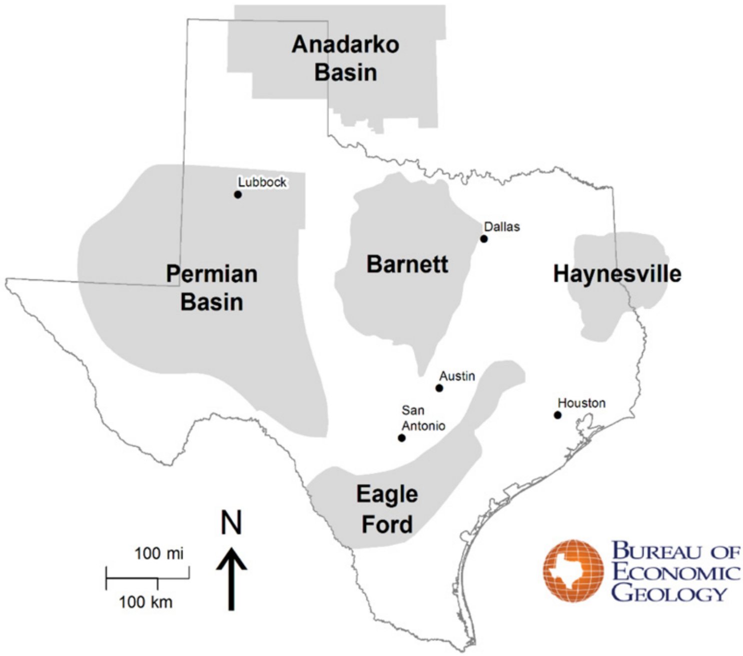

FIGURE 1-1 Major regions of oil and gas activity in Texas.

Although these resources have been known to exist for decades, rapid expansion of oil and gas production from shale formations was made possible by the innovative combined use of two technologies—hydraulic fracturing (referred to colloquially as "fracking") and horizontal drilling. Expansion of oil and gas production has helped reduce dependence from foreign supplies and supported national economic growth by generating jobs and contributing to increases of basic manufacturing processes and products. This domestic oil and gas production resulted in considerable savings for U.S. consumers in the form of reduced gasoline and electricity prices, and generated additional tax revenues for federal, state, and local governments.

At the same time, shale development has consequences. Citizens, communities, environmental groups, and others have raised concerns about seismic activity, injection of chemicals underground, water usage in semiarid areas and potential water contamination, and air emissions as well as noise, trucks, and other impacts associated with hydraulic fracturing activities at the well pad and on supporting transportation networks.

Numerous studies have been carried out to assess environmental impacts associated with shale oil and gas development. This report and its references section list many of these studies and reports, which have been conducted by Texas state agencies such as the Texas Commission on Environmental Quality (TCEQ) and scientists from across the state, especially science and engineering experts at the state's many public and private universities. Given the size and complexities of underground geologic and groundwater systems, atmospheric chemistry, and other systems and fields of study, there remain gaps in some of the underlying scientific knowledge regarding impacts of shale oil and gas development. This knowledge can be diffuse and difficult to locate and access; furthermore, the sheer number of different sources of information can make it difficult to determine the respective credibility of multiple sources of information.

This report from The Academy of Medicine, Engineering and Science of Texas (TAMEST) was developed and written as a consensus report to help address some of the challenges in accessing credible and comprehensive sources of scientific information regarding shale development in Texas. This report includes discussion and explanation of uncertainties in the available information and identifies knowledge gaps where additional information might be especially informative and useful. The report is intended to inform a broad audience on the current state of knowledge and findings from shale development studies in Texas.

The report was authored by an ad hoc task force convened by TAMEST with a membership of 19 experts from across the state in the following subject matter areas: 1) geology and earthquake activity; 2) land resources; 3) air quality; 4) water quantity and quality; 5) transportation; and 6) economic and social impacts.[2]

SHALE WELL TECHNOLOGY DEVELOPMENT

Shale wells combine two technologies: hydraulic fracturing and horizontal drilling. In the United States, hydraulic fracturing dates back to experimentation in the late 1940s, with the first commercially successful well being developed shortly thereafter. The hydraulic fracturing process has been a key method in the extraction of oil and gas resources, having been used in millions of wells in the United States and other parts of the world. Horizontal wells were drilled in the Soviet Union in the 1950s, but the added cost of the wells discouraged this approach at the time. Horizontal well drilling re-emerged in the 1980s with success in the Rospo Mare Field in Italy (Reiss, 1987). The U.S. Department of Energy made substantial investments into shale development processes in the 1970s that helped promote more sophisticated and effective means for shale exploration and extraction (US DOE, 2011).

Much of the credit for the successes of shale development technologies goes to

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[2] For more information about the TAMEST Shale Task Force, see www.tamest.org/shaletaskforce.

the late George Mitchell (Waters et al., 2006). In the 1980s and 1990s, his company tried a variety of hydraulic fracturing strategies in the Barnett Shale region of Texas. Innovations employed in the Barnett Shale during the late 1990s to the early 2000s demonstrated that organic rich tight formations could be developed economically. Successful wells today employ a second essential technology—namely, horizontal wells—that was introduced through a collaboration between the Mitchell Energy and Devon Energy companies. Combining horizontal wells with hydraulic fracturing provided a technological template for production of other shale plays across the state and the nation.

SHALE DEVELOPMENT IMPACTS IN TEXAS

The following sections present some facts and figures regarding shale development in Texas.

Texas Oil and Natural Gas Status[3]

As of this report's publication in 2017, Texas led the nation in production of both oil and natural gas. Texas holds more than a quarter of U.S. proven natural gas reserves, and almost one-third of the nation's crude oil reserves (EIA, 2017a).

In late 2016, the U.S. Geological Survey (USGS) released an estimate of energy resources in the Wolfcamp Shale in the Midland Basin portion of Texas' Permian Basin province indicating a mean of 20 billion barrels of oil, 16 trillion cubic feet of associated natural gas, and 1.6 billion barrels of natural gas liquids in the area (USGS, 2016). This estimate for continuous tight oil consists of undiscovered, technically-recoverable resources. The estimate of continuous oil in the Midland Basin Wolfcamp Shale assessment is nearly three times larger than that of the 2013 USGS Bakken-Three Forks resource assessment, making this the largest estimated continuous oil accumulation that the USGS has assessed in the United States to date. Proven reserves and this recent discovery will likely ensure that Texas will continue to be the nation's largest producer of oil and gas resources for many years. Distribution networks supply Texas oil and natural gas to every major U.S. based oil market east of the Rocky Mountains, and supply Texas natural gas to Mexico. Additionally, Texas oil and natural gas are now shipped globally, and two major Texan liquefied natural gas (LNG) import terminals are being converted to process gas for export, with additional terminals being planned.

The oil and gas industry in Texas accounts for an annual gross product of $473 billion as well as nearly 3.8 million jobs. In addition to economic output

[3] Unless otherwise specified, data in this section are from the Energy Information Administration 2017 state profile of Texas (see EIA, 2017a).

and employment, shale development generates royalty payments to those who own the mineral interests. In 2014 alone, production in the Permian, Eagle Ford, and Haynesville shale play areas accounted for more than $27 billion in royalty payments to private landowners, or more than two-thirds of the royalties from America's leading shale oil and gas plays.

Future Energy Production Scenarios

Whether the development of shale resources continues at the same pace in the future depends upon a mix of many factors, including commodity prices, resource/development availability, and pace of technological developments. The Energy Information Administration (EIA) has projected five scenarios based upon different outcomes relative to these factors. These scenarios range from very high potential for future growth to a decline or cessation of growth (Figure 1-2; EIA, 2016b). Science and technology research will continue to play key roles in enabling continued industry innovation to improve development effectiveness and efficiencies.

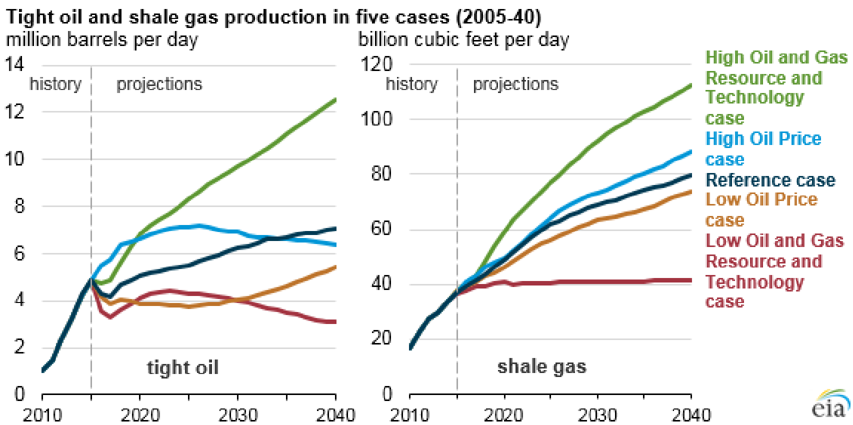

FIGURE 1-2 Tight oil and shale gas production scenarios.
SOURCE: Energy Information Administration, 2016b.

Other Impacts of Shale Development

On a national level, due to technological innovations in shale development, shale gas and tight oil production now account for about 50 percent of total national oil and gas production (EIA, 2016b). Past growth and future projections of U.S. tight oil and shale gas production, including the main Texas contributions, are illustrated in the two panels in Figure 1-3. U.S. oil production started to rise in 2008, with a sharper rise in production starting around 2011. Natural gas production saw a sharp rise in production starting around 2008. The reason for this difference is because the technology was proven first for shale gas, then for tight oil.

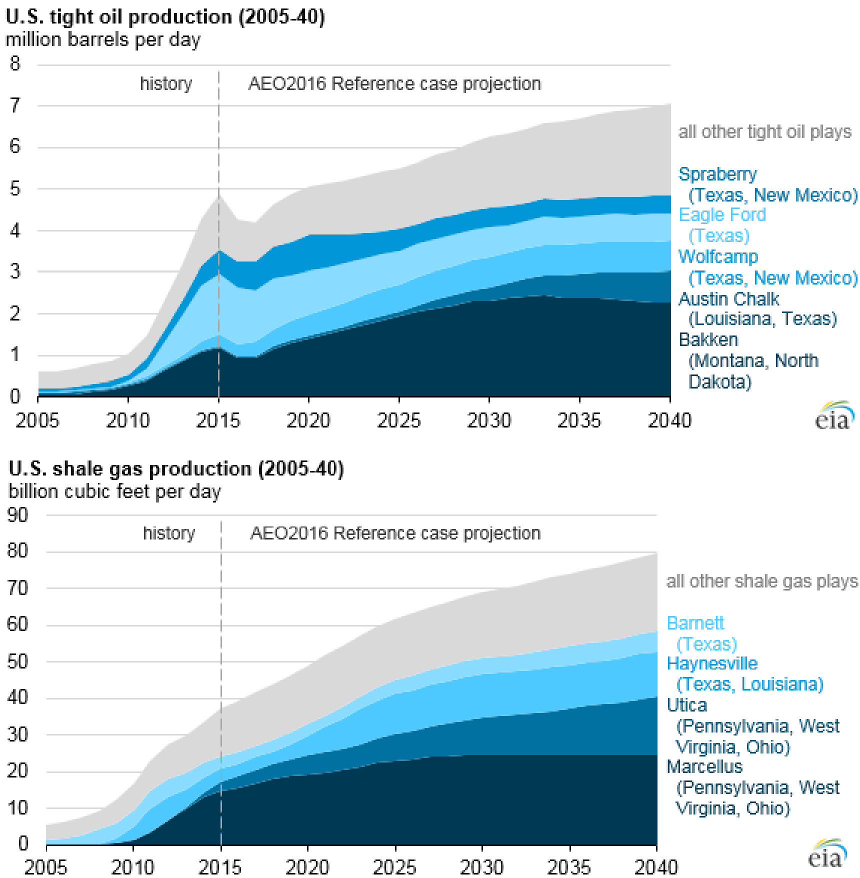

FIGURE 1-3 U.S. tight oil and shale gas production.
SOURCE: U.S. Energy Information Administration, 2016b.

Along with benefits of shale oil and gas development in Texas and elsewhere, there are also negative impacts. For example, shale development operations require movement of heavy equipment and machinery, and can result in substantial wear and tear on roads and other transportation systems. The activities increase traffic and noise, which are concerns in both suburban and rural settings. Some possible negative effects, such as impacts on school classroom sizes, rapid increases in traffic and congestion, or impacts on some animal and plant species, by contrast often are less clear and less immediate. Measurement and explanation of these types of impacts requires monitoring and collection of data in order to conduct objective and rigorous evaluations, highlight uncertainties, and arrive at conclusions.

Report Contents

Following this introductory chapter, Chapter 2 explains some fundamentals on shale oil and gas development. This is followed by six chapters, each related to one of the key topic areas planned for this report: geology and earthquake activity, land resources, air quality, water quantity and quality, transportation, and economic and social impacts. A final chapter notes key elements that can be better understood and explained through consideration of transdisciplinary connections among the six topic areas.

Much of the report's six chapters focuses on the underlying knowledge base that informs scientific analysis. A major concern regarding shale development is the possibility that these activities might result in earthquakes. For example, seismicity has been triggered in Texas, and to a greater extent in Oklahoma and other states, by the injection of large amounts of water produced as a by-product of the oil and gas development process into underground injection wells. The risk of increased seismic events is a matter of concern for scientists, communities, and local officials and citizens. As Chapter 3 explains, Texas geology and seismicity long has been a topic of extensive interest and research. Historical science knowledge of Texas geology is useful in helping better understand seismic implications of modern shale development activities.

Chapter 4 addresses ecosystems research of shale development impacts, many of which are associated with conventional oil and gas exploration and development and are not unique to shale development.

Chapters 5 and 6 discuss risks regarding atmospheric emissions and groundwater contamination, respectively. Chapter 6 discusses both water quality concerns, and water availability and effects on local water supplies. The typical hydraulic fracturing fluid is mainly water, and hydraulic fracturing in a typical shale well can require more than four million gallons of water. At the state level, the total volume of water used for hydraulic fracturing is small compared to other industrial water uses; however, at regional and local scales, especially in the state's more arid regions, use of water for shale development may compete with municipal or agricultural needs.

The effects of activities at a given well pad on local road systems include increases in traffic, wear and tear on local roads (often not designed for large volumes of heavy truck traffic), along with implications for safety and traffic injuries and accidents. Chapter 7 discusses these impacts in detail.

Texas communities and residents also share a wide range of concerns including impacts on housing prices and affordability, and effects of a large influx of students into school districts with inadequate personnel and facilities. Chapter 8 presents community-level issues and concerns and relevant economics and social research.

The task force noted that in addition to impacts and issues strictly within any one of the report's six topic areas, there are interconnections among them that are important to citizens and elected officials alike. Chapter 9 presents ideas regarding these transdisciplinary connections and their implications for research, decision making, and future shale energy investments.

REPORT GENESIS, PROCESS, AND AUDIENCE

A primary goal of this report from TAMEST was to provide credible information from a group of independent experts in a consensus report for decision makers and the public about the known social, environmental, and economic impacts of shale development in Texas. Task force members were selected for their expertise in various aspects of shale oil and gas development, served as independent volunteers, and were Texas residents while the study was being conducted (2015 to 2017).

The report reviews past and ongoing research, including discussion of relevant scientific uncertainties and knowledge gaps. Box 1-1 lists the statement of task provided to the task force by TAMEST.

BOX 1-1
STATEMENT OF TASK TO THE TASK FORCE

A TAMEST-appointed task force team will review the impacts of shale oil and gas development in Texas. The purpose of the study is to help all Texans understand what we do and do not know about the potential environmental and other impacts of shale development and hydraulic fracturing for oil and gas. The issue is of great concern to Texas and both the public and decision makers are continuously provided potentially confusing and/or conflicting information.

The goal of the study is to evaluate the scientific basis of the current body of information available, both positive and negative, and effectively communicate to the public the current state of knowledge of environmental and community impacts of shale development in Texas.

This study will include assessments of existing studies of impacts on air, water, land, seismicity, transportation, and communities in the shale development areas. Based on these assessments and the expertise represented on the team, the task force will (1) review the scientific and technical methodologies, assumptions, and approaches applied in existing impact studies; (2) identify gaps in the existing work, if any; (3) suggest improvements to reconcile inconsistencies in existing assessments; and (4) make recommendations for further analysis, if needed, to address identified issues related to shale development in Texas.

This report was developed by a process similar to that employed by the National Academies of Sciences, Engineering, and Medicine in its consensus reports. The task force membership consisted of volunteer experts, and a confidential draft report from the task force was sent to a group of (then) anonymous reviewers that provided external review comments. The review process was overseen by a member of the TAMEST Board of Directors who was not a member of the task force.

The task force convened three meetings during the course of the project. Work began after funding was procured from TAMEST and a project sponsor, The Cynthia and George Mitchell Foundation.[4] The first task force meeting was held December 17–18, 2015; the second meeting was held October 5–7, 2016; and a final meeting was held February 21–22, 2017. All meetings were held at The University of Texas at Austin. The October 2016 meeting featured a one-day open public session with invited guest speakers from academia, the private sector, and Texas agencies with shale oil and gas responsibilities and interests (the meeting agenda is presented as Appendix A). The first and third task force meetings were convened in closed session, with discussions focused on project planning, report structuring and writing, and dissemination activities.

The intended audience for this report is broad and diverse. People and organizations in Texas with interest in this report likely will include: Texas state legislators and their staffs; Texas state agency officials and staff members; energy companies; shale oil and gas experts and analysts from across a wide spectrum of disciplines and expertise, including universities, private sector firms, and nongovernmental organizations; and citizens of Texas seeking to learn more about scientific information regarding the effects of shale development and hydraulic fracturing. Experts, officials, and citizens in other U.S. states and nations may also find the report of interest and value.

[4] For more information on The Cynthia and George Mitchell Foundation, visit: http://cgmf.org.

2

Fundamentals of Tight Oil and Shale Gas Development

Although this report's title refers to shale development, the report addresses development of hydrocarbon-rich source rock and tight oil and gas. Shale is one formation type of interest, but not the only one. Specifically, this report concerns development of massive formations that require multiple hydraulic fractures per well in order to be commercial.

For the purposes of this report, the term "hydrocarbon" refers to crude oil and natural gas, and coal is excluded. The hydrocarbon resource triangle shown in Figure 2-1 helps explain the distinction between the resource development highlighted in this report and conventional oil and gas development that has occurred in Texas for more than 100 years. Conventional resources appear at the top of the triangle because they represent only a small fraction of the known hydrocarbon resources. Resources in the middle of the triangle, such as tight oil and gas and shale oil and gas, have much greater volumetric extent than typical conventional fields both because of very large thickness and very large areal extent. Other resources in the middle of the triangle include coalbed methane and heavy oil; these are not addressed in this report because they do not rely on the same well design technologies for profitable development and because they have not represented key development activity in Texas. At the base of the triangle are resources known to be in even greater abundance, but for which commercial extraction is not currently viable with existing technologies.

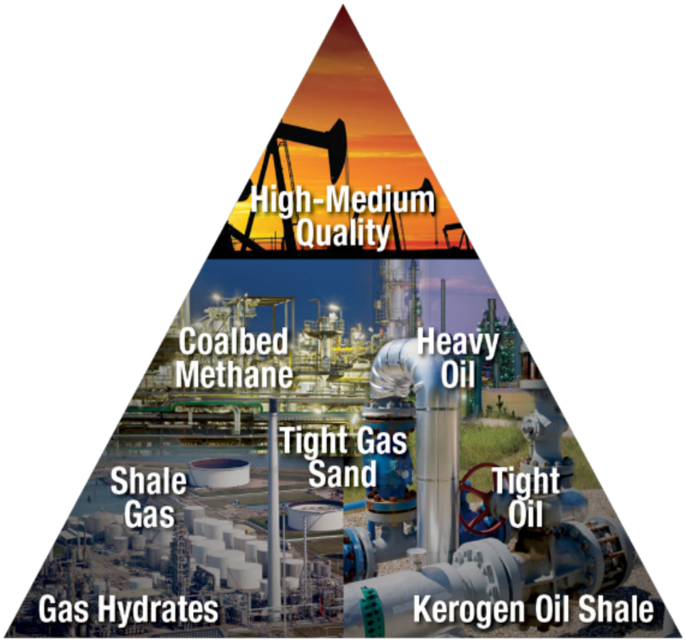

FIGURE 2-1 Hydrocarbon resource triangle.
SOURCE: Adapted from Holditch, 2009.

Figure 2-2 may help the reader to appreciate the distinction in another way. This map shows key resource plays in the Midland Basin overlain by conventional oil fields. The resource plays blanket huge areas and thicknesses, and most conventional fields appear small by comparison. Texas oil and gas producers have been aware of the resource plays for decades because wells were drilled through them in order to find the conventional fields. However, until recently, operating companies left them behind in favor of easier-to-develop conventional fields.

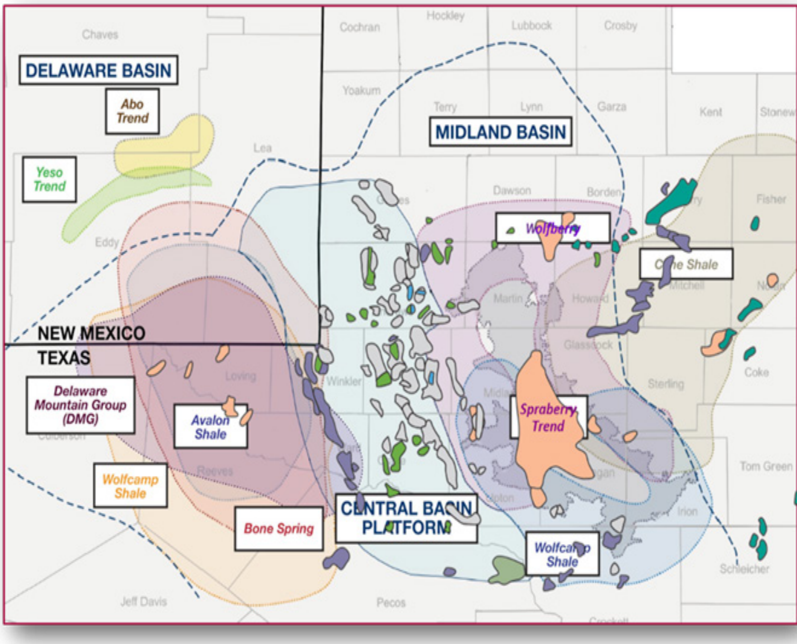

FIGURE 2-2 Conventional reservoirs (small outlined shapes) overlying known shale resource plays (large pastel-shaded regions) in the Permian Basin near Midland, Texas. Wells located in any of the shaded plays may profitably produce oil for a sufficiently high oil price.
SOURCE: EPT.

The rest of this chapter provides a general description of the combined horizontal well and hydraulic fracturing technologies (see NETL, 2009 and King, 2010 for similar descriptive overviews). Figure 2-3 shows conceptual diagrams of modern well designs that are commonly used depending on the reservoir characteristics such as permeability, net reservoir "pay"—or parts of a formation containing producible hydrocarbons—thickness relative to gross reservoir height. These parameters generally will drive selection of well trajectory (horizontal vs. vertical) and selection of multi-stage hydraulic fracturing methods.

One advantage of horizontal wells is their length, which allows creation of many hydraulic fractures. Very thick formations may use a vertical well with many hydraulic fractures within the pay thickness instead of horizontal wells. Permeability is a key formation parameter for well construction design. Permeability is a measure of how easily fluids flow through the rock. For oil or gas formations, the term tight is synonymous with very low permeability. Figure 2-3 illustrates how widespread hydraulic fracturing is in modern well designs. The red circle indicates the well design featured in this report. In addition to enhanced production capacity provided by horizontal drilling, this process has far less impact on the landscape and land resources than does vertical drilling.

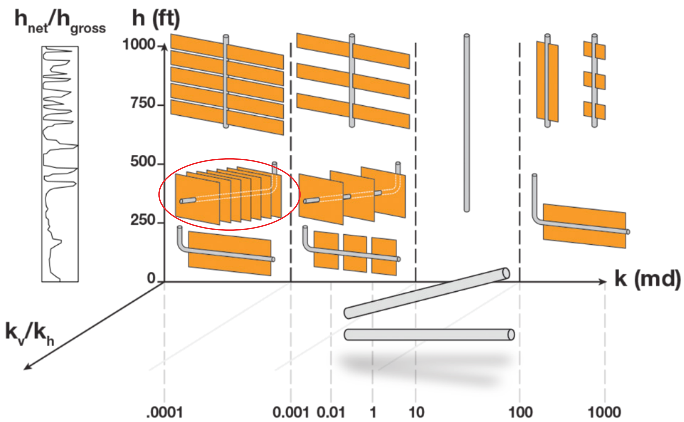

FIGURE 2-3 Modern well designs. Grey cylinders are wells, and orange planes are hydraulic fractures. The red outline indicates well designs of interest for this report. The symbols are h for formation thickness, k for permeability (md is millidarcy); subscripts are v for vertical, h for horizontal, net for producible pay out of a total gross pay thickness.
SOURCE: EPT, 2015.

Figure 2-4 shows a conceptual diagram of the well design most commonly used in shale gas and tight oil formations. The drilling starts with a vertical segment and turns horizontal into the formation to be produced. Once in a horizontal direction, drilling can continue to a design trajectory length. Wells are typically 5,000 to 10,000 feet in horizontal length. After the well is drilled, hydraulic fractures are pumped in stages. When all stages have been hydraulically fractured, the well is ready to flow as soon as the wellhead is connected to a production facility that, in turn, is able to transport oil and/or gas to a buyer. During the first few days of flow, some of the fracturing fluid is produced back through the wellhead for recycling or disposal. Soon the production is mainly oil and/or gas. Chapter 6 explains impacts of water use and its management, recycling, or disposal in shale energy development processes.

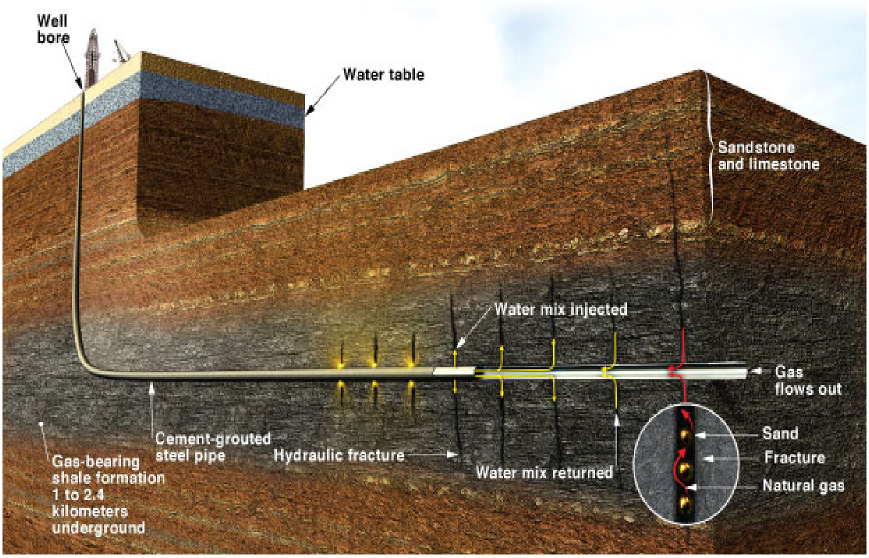

FIGURE 2-4 Diagram showing hydraulic fractures in a horizontal well drilled into a shale formation.
SOURCE: Ryerson, 2014.

Fractures are created by pumping hydraulic fracturing fluid at a sufficiently high pressure to initiate a narrow crack in the formation. Continued pumping at high pressure extends the length of the narrow crack up to several hundred feet. Sand or ceramic proppant is mixed with the fracturing fluid during pumping to form a slurry to be pumped into the created crack. The proppant props the fracture open and provides a very high permeability path for oil or gas to flow toward the horizontal well. Several hundred thousand pounds of proppant are pumped into fractures in each stage along with approximately 200,000 gallons of fracturing fluid. Since fracturing fluid is mostly water, the total hydraulic fracturing job would require about two million gallons of water. Proppant and water are transported to the wellsite typically by truck. Chapter 7 of this report addresses roadway wear associated with transport of materials and wellsite personnel, and there it is explained that a typical Eagle Ford well uses about 1,700 truckloads of materials (Table 7-2).

Figure 2-5 shows a photograph of an Eagle Ford Shale development pad during hydraulic fracturing. A typical Eagle Ford well is drilled vertically to a depth of 6,000 feet and then horizontally in the formation for 5,000 to 10,000 feet (1 to 2 miles). Hydraulic fractures are created in stages starting from the toe of the horizontal well. Each stage may contain up to six fractures, and there may be from 10 to 20 stages. Once all the wells have been drilled from any given pad, the land surface can be restored to former use or condition leaving only wellheads, pumps (if an oil well), a small production facility, a storage tank, and/or pipelines for transport to a buyer. Chapter 4 addresses impacts on the land surface.

FIGURE 2-5 Photograph of hydraulic fracturing operation in the Eagle Ford Shale. The green trucks are pumps for hydraulic fracturing. Behind them are containers with water, sand, and other materials used for hydraulic fracturing. A wellhead tree appears in front of the pump truck array and behind a yellow crane. SOURCE: Image courtesy of Yantis Company.

Figure 2-6 illustrates one operator's strategy in the Cline Shale in the Permian Basin using an array of horizontal wells each with multiple hydraulic fractures. Because of the low permeability, very little hydrocarbon is produced outside of the volume delineated by the hydraulic fracture array. Several wells can be drilled from a drill site (or well pad) at multiple depths and from multiple starting points for the horizontal well segment. Such pad developments can produce an underground volume more than 1,000 feet thick and in an area 1 mile thick and 2 to 4 miles long with pad surface area of about 1 to 2 football fields.

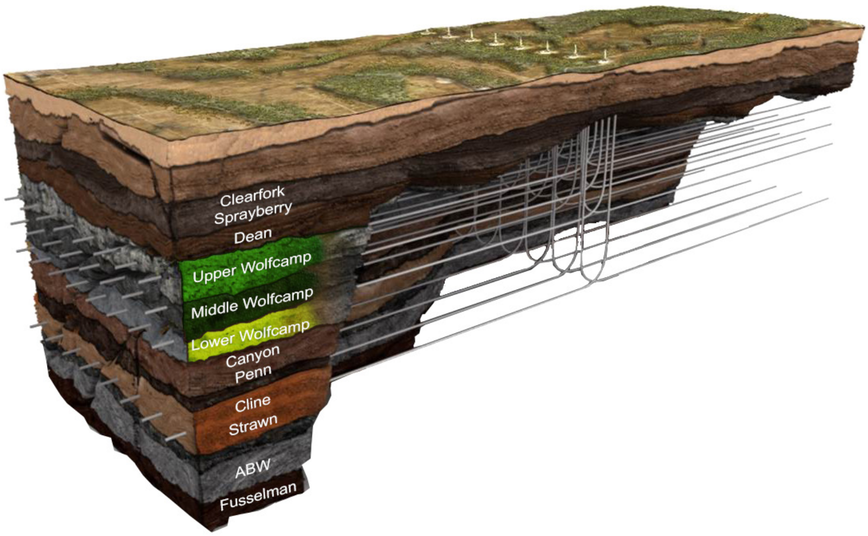

FIGURE 2-6 Diagram showing pad well drilling concept. Each well will have roughly uniformly spaced hydraulic fractures created perpendicular to the horizontal well segment.
SOURCE: Image courtesy of Laredo Petroleum.

During hydraulic fracturing acoustic sensors may be used to monitor approximately where the fracture propagates. Figure 2-7 shows a three-dimensional view of the locations creating acoustic signals during hydraulic fracturing. The signal locations reflect roughly the trajectories and destinations of fluid and proppant. The vibration amplitudes during fracturing are in the microseismic range. That is, they are less than one-millionth the amplitude of vibrations felt as earthquakes.

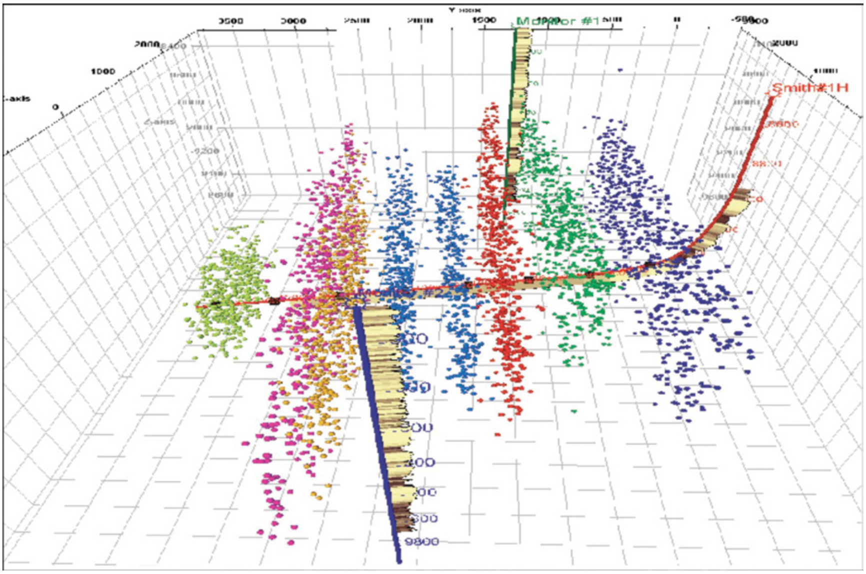

FIGURE 2-7 Three-dimensional view of microseismic events sensed during hydraulic fracturing. Events are colored differently for each separate stage.
SOURCE: Baihly et al., 2007.

There has been considerable discussion regarding possible relations between earthquake level vibrations and hydraulic fracturing. Chapter 3 addresses the topics of earthquakes and seismicity. It provides a description of relevant geological studies conducted in Texas, and discusses several relevant topics related to seismology in Texas, and how seismic activity may potentially be induced by water disposal operations and the hydraulic fracturing process.

3

Geology and Earthquake Activity

- Geologic faults are ubiquitous across Texas; these faults are poorly and incompletely characterized.
- Mechanisms of both natural and induced earthquakes in Texas are not completely understood.
- The majority of known faults in the subsurface in Texas are stable and are not prone to generating earthquakes.
- There has been an increase in the rate of recorded seismicity in Texas over the last several years. Between 1975 and 2008 there were, on average, one to two earthquakes per year of magnitude greater than M3.0. Between 2008 and 2016, the rate increased to about 12 to 15 earthquakes per year on average.
- Under certain unique geologic conditions, faults that are at or near critical stress may slip and produce an earthquake if nearby fluid injection alters the effective subsurface stresses acting on a fault.
- To date, potentially induced earthquakes in Texas, felt at the surface, have been associated with fluid disposal in Class II disposal wells, not with the hydraulic fracturing process.

The underlying strata and geological formations across Texas have provided an abundance of natural resources, including the recent developments of shale oil and gas resources. The development of these resources, and the attendant seismic and other geological implications of those activities, requires knowledge of the permeability of widely varying geologic formations and subsurface stress regimes and tectonics and how they are affected by hydraulic fracturing processes. This chapter presents an overview of Texas geology and subsurface features and dynamics that puts shale resource development into a broad perspective, and provides a foundation for discussion and facts pertinent to subsequent sections of the report.

The topics of water quantity and quality are addressed later in Chapter 6. It is worth noting here the interplay between subsurface water systems and geology and subsurface processes and features. In the hydraulic fracturing process, water is recovered along with oil and gas, and it can be a combination of 1) produced formation water that co-exists with the oil and gas in the reservoir and 2) flowback of water pumped into the reservoir as part of the hydraulic fracture process that is used to increase the well productivity and thus enable resource recovery. This water either must be recycled or disposed of at depth. It has long been known that under certain circumstances, water injected at depth can induce earthquakes on existing faults (Healy et al. 1968; Nicholson and Wesson, 1990). Seismicity is defined as "the occurrence or frequency of earthquakes in a region." Therefore, an understanding of Texas seismicity and its relationship to these processes is critical to assessing implications of oil and gas recovery in Texas and across the United States. This chapter refers to these types of earthquakes as "induced seismicity."

This chapter builds on a number of national studies of oil and gas operations and their relationships to induced seismicity. The National Research Council (NRC)[5], for example, conducted a prominent and comprehensive study of induced seismology, issuing a report in 2012 (NRC, 2012). The NRC study was followed by a multi-year study conducted by the U.S. Environmental Protection Agency (EPA) that focused on managing and mitigating the linkages between fluid disposal and earthquakes (EPA, 2015). Finally, another 2015 report was issued by a team of state regulators, industry representatives, and subject matter experts that documented possible relationships between wastewater disposal and earthquakes, and illustrated proactive mitigation approaches (Groundwater Protection Council and Interstate Oil and Gas Compact Commission, 2015).

Government, industry, and academic representatives from Texas all have been active participants in these studies, putting Texas on the forefront of exploring, assessing, and mitigating the relationships between induced seismicity and oil and gas operations. In recognition of the importance of geological issues to Texas, the state legislature passed a bill in 2015, House Bill 2, that appropriated $4.47 million to The University of Texas at Austin for the purchase and deployment of seismic equipment, maintenance of seismic networks, and modeling of the reservoir behavior for systems of wells in the vicinity of faults. This effort is referred to as "TexNet," and this initiative is referenced several times throughout the chapter (see BEG, 2016 for a review of progress on House Bill 2 and TexNet).

This chapter is comprised of six major sections, and a summary section that

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[5] The National Research Council (NRC) was formerly the research arm of the National Academies. As noted in Chapter 1 of this report, the National Academies body consists of the National Academy of Sciences (NAS), National Academy of Engineering (NAE), and National Academy of Medicine (NAM). The NRC was founded in 1916. In 2016, the name 'National Research Council' was eliminated from the organization. The name change entailed essentially no internal staffing changes, or any changes to the organization's legislative obligation and capacity to serve as an independent advisor, on request, to the U.S. Congress.

includes findings and recommendations. The sections are: 1) Texas Geology and Earthquakes; 2) Progress in Understanding and Assessing Potential for Induced Seismicity in Texas; 3) Induced Earthquakes and Fluid Injection; 4) Hazard and Risk from Texas Earthquakes; 5) Roles of the Railroad Commission (RRC) of Texas in Induced Earthquake Mitigation Strategies; and 6) Reducing Knowledge Gaps in Texas Geology and Seismicity. The chapter concludes with a brief summary section that includes findings and recommendations.

TEXAS GEOLOGY AND EARTHQUAKES

This section is divided into three sections: 1) Texas Geology, Including the Basement; 2) Texas Tectonics and Subsurface Stress; and 3) Texas Earthquakes.

Texas Geology, Including the Basement

Geologic strata and features of Texas are the result of over one billion years of geologic activity as seen in the igneous and metamorphic rocks exposed in the Llano Uplift of Central Texas (Garrison et al., 1979). Subsequent folding, faulting, mountain building, erosion, and rising and falling sea levels, all driven by tectonic forces that cause movement of the earth's crust, formed and filled the many sedimentary basins that produce hydrocarbons today. The contours in Figure 3-1 depict the sub-sea level depth of igneous and metamorphic "crystalline" basement overlain by sedimentary deposits. The basement rocks exposed in the far western mountainous region are the southern end of the recent geologically formed Rocky Mountains. Basement rocks exposed in the Llano Uplift represent basement rock that was formed over one billion years ago. Black lines and curves that cross contours represent breaks in the crust called faults.

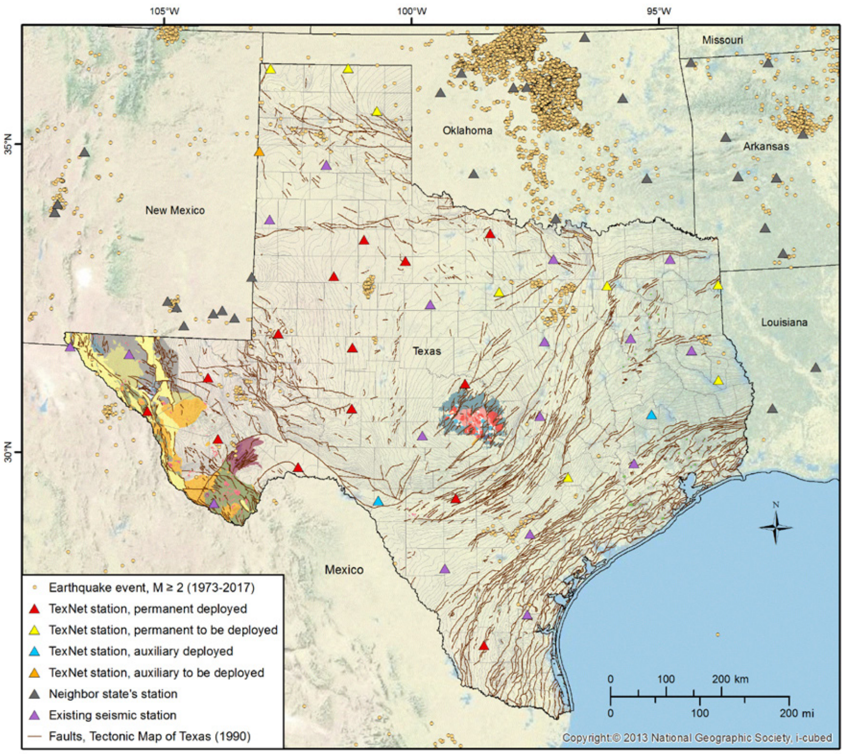

FIGURE 3-1 Map of Texas and surrounding states showing earthquakes from the USGS earthquake database, existing and proposed TexNet seismic stations, and structure of key stratigraphic units portraying the complex tectonic architecture and fault systems in Texas.
SOURCE: BEG, 2016 (after Ewing, 1991).

The vast amount of organic rich sediment deposited in the basins of what is now Texas has made Texas a leading producer of hydrocarbons. Figure 3-2 depicts the seven major hydrocarbon-rich basins in Texas.

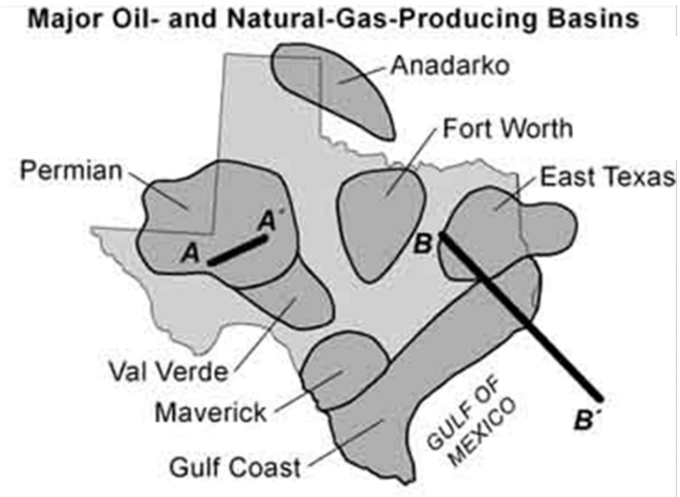

FIGURE 3-2 Major oil and natural gas producing basins of Texas. Cross-section A-A' reflected in Figure 3-2; cross-section B-B' reflected in Figure 3-4.[6]
SOURCE: Modified from Bebout and Meador, 1985.

The Permian Basin in West Texas and Southeast New Mexico and the adjoining Val Verde Basin, along with the Fort Worth and Anadarko Basins of North Central Texas, contain oil- and gas-producing sediments deposited during the Ordovician Age (between 488 million and 444 million years ago). The massive Ellenberger Limestone is an Ordovician deposit found in the Permian and Fort Worth Basins. The equivalent formation in the Texas Panhandle region is the Arbuckle Limestone. Major shale formations in the Permian Basin include the Woodford of Devonian age; Barnett of Pennsylvanian age; and Bone Springs, Spraberry, and Wolfcamp of Permian age.

[6] Ages of geologic formations often are indicated by the name of the historic era or period during which they were originally deposited. Following is a list of the geologic eras and periods of interest in this discussion, and the age range for each in millions of years before present: Cenozoic era (0.01 to 65), including Quaternary (0.01 to 1.8), and Tertiary (1.8 to 65) periods; Mesozoic era (65 to 248), including Cretaceous (65 to 144) and Triassic (206 to 248) periods; Paleozoic era (248 to 548), including Permian (248 to 290), Pennsylvanian (290 to 323), Mississippian (323 to 354), Devonian (354 to 417), Silurian (417 to 443), and Ordovician (458 to 490) periods; and Precambrian era (543 and older).

Figure 3-3 is a graphical representation of the A-A' cross section from Figure 3-2. This cross section begins in the deep Delaware sub-basin portion of the Permian Basin and transects the Central Basin Platform, ending by crossing the Midland sub-basin portion of the Permian Basin. Sediment thickness in the deepest portion of the Delaware sub-basin approaches 11,500 feet and thins to approximately 5,000 feet over the Central Basin Platform. Plays in the North Central Texas region include Barnett Shale in the Fort Worth Basin, and Granite Wash formation in the Anadarko Basin, both of which are of Mississippian age. Figure 3-3 shows faults that break deposited beds that once were continuous.

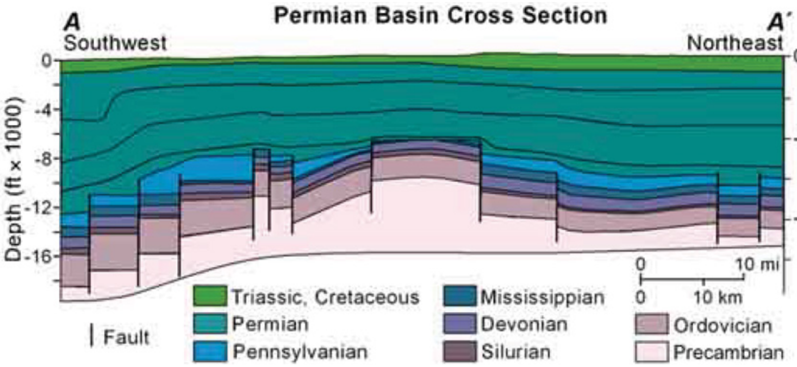

FIGURE 3-3 Cross section of the Permian Basin of Texas. Section A-A' spans the deep Delaware Basin, high Central Basin Platform, and moderately-deep Midland Basin provinces of the Permian Basin. The Permian age sediments vary in thickness from 11,500 feet in the Delaware Basin to 5,000 feet on the Central Basin Platform. Oil and gas have been produced from each of the formations located between the Triassic/Cretaceous surface down to the Precambrian basement.
SOURCE: BEG, 1990.

The Balcones Fault Zone, or Escarpment, is a well-known geologic feature in Texas. This zone trends southwest to northeast across Texas, extending from the vicinity of Del Rio northeastward into North Central Texas near Dallas. Several Texas cities, including Austin, New Braunfels, and San Marcos lie along this fault zone. To the south and east of the Balcones Fault Zone lie the younger hydrocarbon basins of the Gulf Coast region. The large majority of production in the Texas Gulf Coast is from Cretaceous and Tertiary age sediments deposited between 145 and 2 million years ago.

Figure 3-4 shows the B-B' cross section in Figure 3-2 transecting the East Texas and Gulf Coast Basins. A striking and important component of hydrocarbon geology in these basins is the presence of mobile salt deposits that form hydrocarbon-trapping salt domes. The depth of sediments in these two basins is an impressive

50,000 feet. The Haynesville Shale is the primary shale target formation in this area. The other major basin in the Gulf Coast region is the prolific Maverick Basin where the gas- and oil-rich Eagle Ford Shale of Cretaceous age is found. The Eagle Ford is the largest of the Gulf Coast region shale plays, and it extends well to the east and northeast of the Maverick Basin.

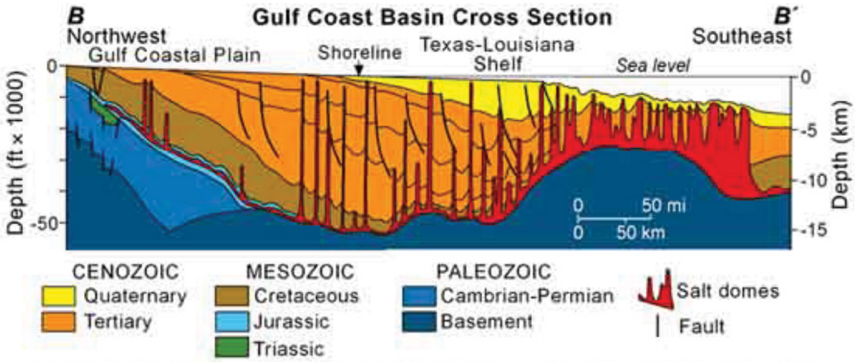

FIGURE 3-4 Cross section of the East Texas, Gulf Coast, and Gulf of Mexico Basins of Texas. Section B-B' spans the complex transition from the East Texas Basin Mesozoic-aged sediments and the mobile Louann Salt across the salt-tectonic-dominated Gulf Coast and Gulf of Mexico Basins.
SOURCE: BEG, 1990.

Existing faults shown in the map in Figure 3-1 and the cross sections in Figure 3-3 and 3-4 have been found largely through exploration for oil and gas and other specific endeavors involving acquisition of data that may reveal their presence.

Geologic faults are ubiquitous across Texas; these faults are poorly and incompletely characterized.

Additional details of Texas geology can be found in Ewing, 2016, which provides a recent and comprehensive reference describing Texas geology and its evolution through geologic time.

Texas Tectonics and Subsurface Stress

Stress in the subsurface must be understood in order to assess whether existing faults are geologically dormant or if changes to pore fluid pressure may be sufficient to make them unstable. Understanding the subsurface stress conditions is therefore important to managing risks associated with induced seismicity along faults at depth. However, development of more detailed understanding of the subsurface stress distribution is challenged by sparseness of data, and the fact that many different entities collect various formats of data.

Recognizing the need for better mapping of stress data, since the mid-1990s the World Stress Map (WSM) project, administered by GFZ German Research Centre for Geosciences, has provided a global compilation of information on the present-day stress field of the Earth's crust, with over 20,000 stress measurements contained in the global database (GFZ German Research Centre for Geosciences, 2015). This collaborative project between academia, industry, and government aims to characterize global seismological stress patterns and to understand their sources. Figure 3-5 illustrates published stress data in the United States.

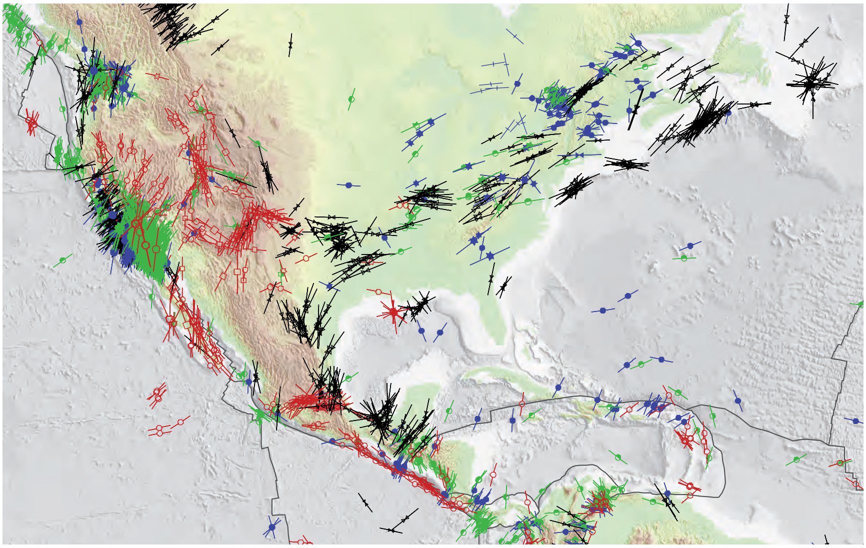

FIGURE 3-5 World Stress Map data, illustrating the direction of the greatest horizontal stress field across the United States. The red stress orientations correspond to normal faulting regimes, green to strike-slip faulting, and blue to thrust faulting. The sparseness of data across the mid-continent of the United States creates uncertainty in understanding stress fields at smaller scales.
SOURCE: Heidbach et al., 2009.

Advances in understanding the importance of *in situ* stress on induced earthquakes, including recent work by scientists at Stanford University (Lund Snee and Zoback, 2016), have led to a resurgence in interest in these topics. Figure 3-6 shows the results from this 2016 study, which illustrates how stress orientation varies across Texas. This research provides a valuable dataset for interpreting possibly induced seismicity across Texas, given that induced earthquakes have been found to be consistent with altered *in situ* stress.

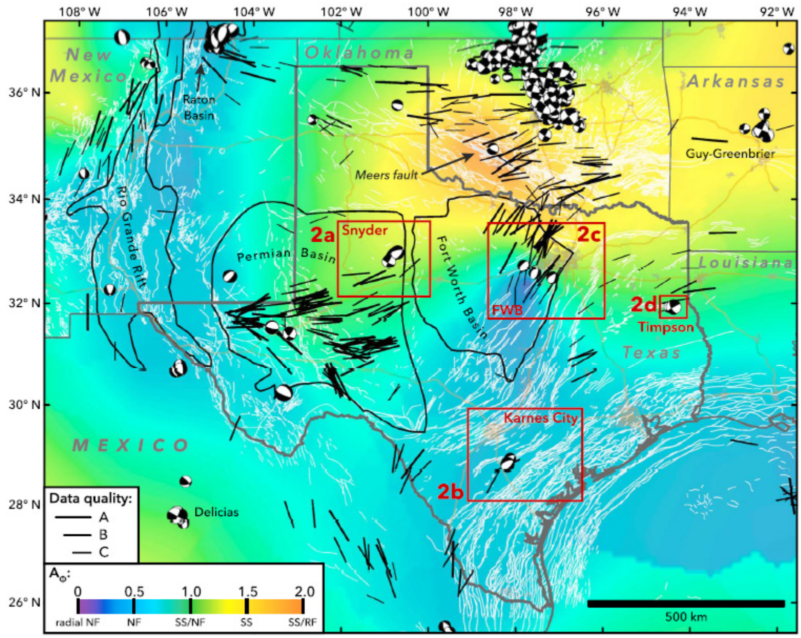

FIGURE 3-6 Stress map of Texas, based on measurements of in situ maximum horizontal stress orientations from drilling-induced tensile fractures and borehole breakouts observed in wellbore image logs, maximum horizontal shear wave velocity from crossed-dipole sonic logs, and hydraulic fractures from microseismic data. SOURCE: Lund Snee and Zoback, 2016.

Texas Earthquakes

Documented earthquake activity in Texas goes back to 1847 with early reports primarily based upon "felt" reports as documented in local newspapers at the time (Frohlich and Davis, 2002). Since these early events were not recorded by sensitive seismographic equipment, the lower magnitude threshold is approximately M3.0[7] based on rough estimates of the minimum magnitude of earthquakes that can be felt. According to the U.S. Geological Survey (USGS), "USGS research considers

[7] The magnitude scale was introduced in 1935 by Charles Richter in order to provide a single number to quantify the size of an earthquake. Although the Richter magnitude has been expanded beyond its initial definition in California, magnitude scales are based on the logarithm to base 10 of the observed amplitude of a particular seismic phase, with a correction for the distance to the earthquake. The logarithm is used to account for the vast differences in sizes of earthquakes, which means that an increase in 1 magnitude unit is proportional to a factor of 10 increase in observed ground motion (Bolt, 2005).

a magnitude 2.7 earthquake to be the level at which ground shaking can be felt. An earthquake of magnitude 4.0 or greater can cause minor or more significant damage" (USGS, 2017a; see also Groundwater Protection Council and Interstate Oil and Gas Compact Commission, 2015, for detailed discussion of magnitude values, levels of ground motion, and damage accompanying earthquakes).

The threshold for humans to feel ground motion from an earthquake is a complex function of magnitude, depth of the earthquake, local surface geology, distance from the earthquake, how stress is relieved on the fault, and local conditions of the observer. The difference in energy between magnitude levels is slightly more than a factor of 30. For example, it would take more than thirty M4.0 earthquakes to release the energy of a single M5.0 earthquake. This illustrates that moderate numbers of small earthquakes do not substantially release appreciable energy or reduce risk for subsequent larger earthquakes.

There are no active tectonic plate boundaries in Texas. Motion along tectonic plate boundaries provides a mechanism for storing elastic energy along faults that mark major boundaries between plates. As for other parts of the stable North American continent, small to moderate earthquakes are possible, but they are less frequent than at plate boundaries, such as those found along the Pacific coast (Petersen et al., 2014).

The majority of known faults in the subsurface in Texas are stable and are not prone to generating earthquakes.

Implementation of a national seismic network enabled more precise estimation of earthquake locations and the magnitude or size of each earthquake. The deployment of seismic instruments across the Central and Eastern United States in the 1960s and 1970s provided a comprehensive basis for detecting and locating earthquakes down to an approximate magnitude of M3.0 (NRC, 2012). In 2005, there were six permanent seismographic stations in Texas. By 2015, that number had increased to 17. Implementation of the TexNet initiative will add an additional 22 permanent seismic stations in Texas as well as employ 36 portable stations for monitoring local areas of interest, as currently is being carried out in the Dallas-Fort Worth area.

Seismicity in Texas is broadly distributed across four primary areas including West Texas, the Texas Panhandle, Northeast Texas and South Central Texas (Frohlich and Davis, 2002). Historically, the state has experienced several earthquakes above a magnitude of M5.0. On August 16, 1931, near Valentine, there was an earthquake with an estimated magnitude of M5.6 to M6.3 (Doser, 1987). An earthquake with magnitude between M4.7 and M5.3 was recorded near Dalhart on March 12, 1948 (Nuttli, 1979). A third, moderate-sized earthquake, with a magnitude estimate of M5.7, was recorded near Alpine on April 14, 1995 (Dziewonski et al., 1996). Texas has a long history of sporadic seismicity; only within the last few decades has seismic instrumentation been available to assess all events down to magnitudes close to M3.0.

With respect to public impacts associated with an earthquake, the USGS uses the Modified Mercalli Intensity (MMI) scale to report earthquakes and their observed impacts. The MMI is a numerical scale that quantifies both the human-perceived ground motion as well as the types of accompanying damage. Figure 3-7 shows a “shake-map” relating citizen reports of ground shaking levels (a) and compares these estimates to estimates of peak ground acceleration (b).

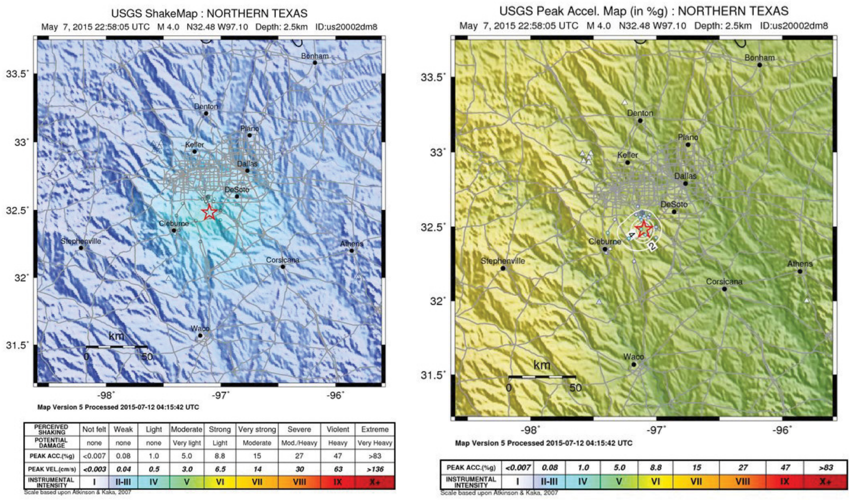

FIGURE 3-7 (left panel) Example of a “shake-map” produced by the USGS that consolidates citizen-reported ground shaking and observed impacts associated with a specific earthquake. Shown in this figure is the “shake-map” from a May 7, 2015 earthquake in the Dallas area (right panel), accompanying estimates of peak accelerations for the same earthquake.
SOURCE: USGS, 2017b.

Of the 162 historical Texas earthquakes, 94 have occurred since 2008. This increase in seismicity is significant because a common instrumental threshold to magnitude M3.0 on the Richter scale extends back to 1975. It is similar to the increase in seismicity covering broader regions of the Central and Eastern United States. Based on the breadth of research studies performed to date, there is a general consensus in the scientific community that significant temporal and spatial increases in seismicity in the Central United States are associated with disposal of wastewater from shale development activities in proximity to existing faults at or near critical stress conditions (Ellsworth, 2013). Figure 3-8 is another illustration of changes in seismicity across Texas. This figure shows the total seismicity rate (number of earthquakes per year) increasing from about two per year before 2010 to about

12 per year after 2010. In a subsequent and more recent analysis associated with TexNet research efforts, between 2008 and 2016, the University of Texas Bureau of Economic Geology (BEG) estimated the rate to have increased to around 15 per year on average (BEG, 2016). As such, the increased rate of seismicity has led to an average of about 12 to 15 earthquakes per year.

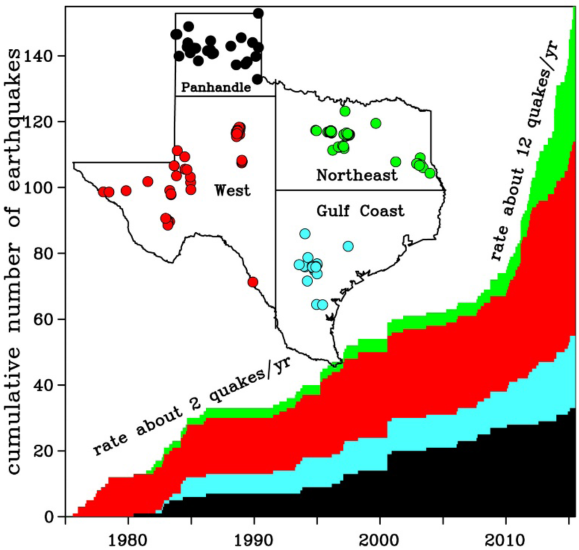

FIGURE 3-8 Texas seismic events since 1975 with magnitude of 3.0 or above.
SOURCE: Frohlich et al., 2016.

There has been an increase in the rate of recorded seismicity in Texas over the last several years. Between 1975 and 2008 there were, on average, one to two earthquakes per year of magnitude greater than M3.0. Between 2008 and 2016, the rate increased to about 12 to 15 earthquakes per year on average.

PROGRESS IN UNDERSTANDING AND ASSESSING POTENTIAL FOR INDUCED SEISMICITY IN TEXAS

This section focuses on induced earthquakes and is divided into three subsections: 1) understanding how injection may induce an earthquake; 2) understanding the complexity in assessing whether injection will cause (or has caused) an earthquake; and 3) understanding progress in Texas: advancing the knowledge and science.

Understanding How Injection May Induce an Earthquake

A fault is a locale or region where sections of the Earth's crust move relative to each other. Stress and strain conditions can lead to motion (slip) of the earth along a fault, Figures 3-5 and 3-6 show mapped stresses in Texas. Earthquakes result from accelerated slip movement on a pre-existing fault. The previous section described the shaking (seismicity) from Texas earthquakes, and noted that recorded seismicity in Texas has increased in recent years.

The vast majority of earthquakes are tectonic—due to natural stresses. Under some circumstances, however, earthquakes can be induced by human activities. Induced seismicity has been documented since at least the 1920s and attributed to a broad range of human activities including underground injection, oil and gas extraction, impoundment of reservoirs behind dams, geothermal projects, mining extraction, construction projects, and underground nuclear tests (Nicholson and Wesson, 1990; NRC, 2012). Understanding how and whether fluid injection has induced an earthquake requires understanding of the spatial and temporal conditions associated with both the earthquake location (hypocenter) and with changes in subsurface conditions associated with fluid injection.

To help explain the challenges entailed by definitively concluding whether a particular earthquake is caused by induced seismicity, or by natural tectonic processes, the remainder of this section describes some fundamental physical mechanisms involved in induced seismicity related to fluid injection. A subsequent section addresses how these mechanisms may apply to waste or produced water injection.

Earthquakes are generated when accelerated slip movement on a pre-existing fault releases stress and strain energy that has accumulated over time. The slip is triggered when the stress that has accumulated along the fault exceeds the frictional resistance for the fault to slide (NRC, 2012). Faults reflect the response of brittle portions of the earth to associated stress and strain.

The key parameters controlling initiation of fault slip are illustrated in Figure 3-9 for the case of a simple frictional fault subjected to elevated pore pressure. The normal and shear stresses on a fault depend on the orientation of the fault and on the state of stress and formation pore pressure. For this illustration, the unique critical condition (or threshold) for fault slip is quantified by the "Coulomb Criterion," which is the product of the friction factor (μ) and the effective stress ($\sigma_n - P$) on the fault where σ_n is the normal stress on the fault (stress in the direction perpendicular to the fault) and P represents any fluid pressure along the fault.

When shear stress τ exceeds the Coulomb Criterion such that $\tau > \mu(\sigma_n - P)$, the stress state reaches critical conditions, whereby the fault can slip. Each circle (called a Mohr circle) shows the values for shear and effective stresses for all possible angles between the plane of the fault and the vertical direction. An increase in the pore pressure, *P*, moves the circle to the left. The earth can slip along the fault plane when the pore pressure is sufficiently high that the blue circle touches or crosses the orange threshold line. Slip along a fault plane causes vibration felt as an earthquake.

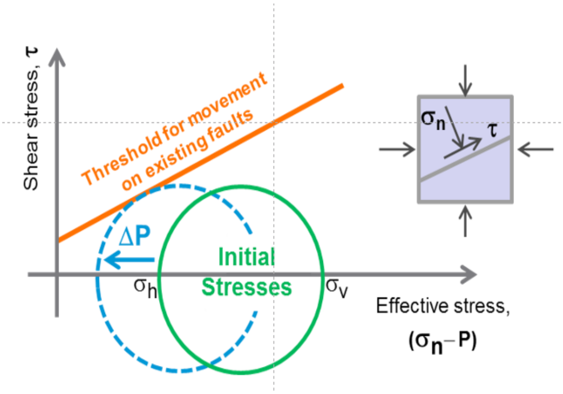

FIGURE 3-9 Illustration of subsurface pressure and stress conditions that are associated with fault stability and fault slip.
SOURCE: Ground Water Protection Council and Interstate Oil and Gas Compact Commission, 2015.

Although fault behavior can be much more complex when considering other factors such as "cohesive" frictional resistance, dynamics of fault rupture, and poro-elastic effects, the above simplified model illustrates a mechanism for fault slip related to elevation of the pore pressure. The common statement and concept that "fluid injection lubricates the fault" is not correct, as fluid injection does not change the friction factor (μ), but instead the effective stress on the fault. The physical understanding associated with the potential for fluid injection to induce earthquakes is more extensively discussed in a number of recent comprehensive studies (e.g., Suckale, 2009; NRC, 2012).

Under certain unique geologic conditions, faults that are at or near critical stress may slip and produce an earthquake if nearby fluid injection alters the effective subsurface stresses acting on a fault.

Understanding the Complexity in Assessing Whether Injection Will Cause (or Has Caused) An Earthquake

In its 2015 study of seismicity associated with disposal well and injection operations, the EPA defined a "Fault of concern" as:

> A Fault of concern is a fault optimally oriented for movement and located in a critically stressed region. The fault is also of sufficient size, and possesses sufficient accumulated stress/strain,

> such that fault slip and movement has the potential to cause a significant earthquake. Fault may refer to a single fault or a fault zone of multiple faults and fractures. (EPA, 2015).

The two activities related to shale well development that involve injection of fluid into a subsurface formation are hydraulic fracturing and disposal of produced water. Although tectonic earthquakes occurring from natural causes cannot be avoided, it is important to try to avoid inducing earthquakes. To understand definitively whether fluid injection will cause, or has caused, an earthquake requires establishing: 1) an understanding of the three-dimensional subsurface pressures and stress field; 2) how the subsurface stresses and pressures are changing both in time and space; and 3) the identification and geologic characterization of the faults that are present in the area, such as size and orientation.

However, large uncertainties associated with the significant heterogeneity present in subsurface formations, the dynamically-evolving tectonic-driven changes to the subsurface stress, and a poorly constrained understanding of reservoir parameters and formation flow pathways significantly impair the ability to characterize the subsurface stress and pressure conditions. Therefore, it is generally difficult and technically challenging to differentiate between induced and tectonic earthquakes based solely on seismological methods. The integration of multiple technical disciplines and skill sets is generally required to perform a causation assessment with collaboration among seismologists, reservoir engineers, geomechanical engineers, geologists, and geophysicists (Ground Water Protection Council and Interstate Oil and Gas Compact Commision, 2015).

Over the last several years, various statistical-based and physics-based analysis approaches have been applied to evaluating causes for earthquakes. Research has considered spatial and temporal correlations of well locations to earthquake epicenters (Frohlich et al., 2016), temporal and spatial correlations involving earthquake hypocenters and subsurface pressures (Davis, 1993), petroleum engineering analytical solutions (EPA, 2015), subsurface reservoir modeling (Gono et al., 2015; Hornbach et al., 2015), and integrated reservoir-geomechanics models (Rutqvist, 2015; Fan, 2016).

A broad appreciation among the public regarding fundamental technical challenges associated with the scientific goal of improving confidence levels for evaluating and determining whether injection operations may cause, or have caused, an earthquake, is important. As Figure 3-10 illustrates, the assessment of whether a particular earthquake can be (or has been) induced by injection often is complicated by both lack of available data and uncertainty in the available data.

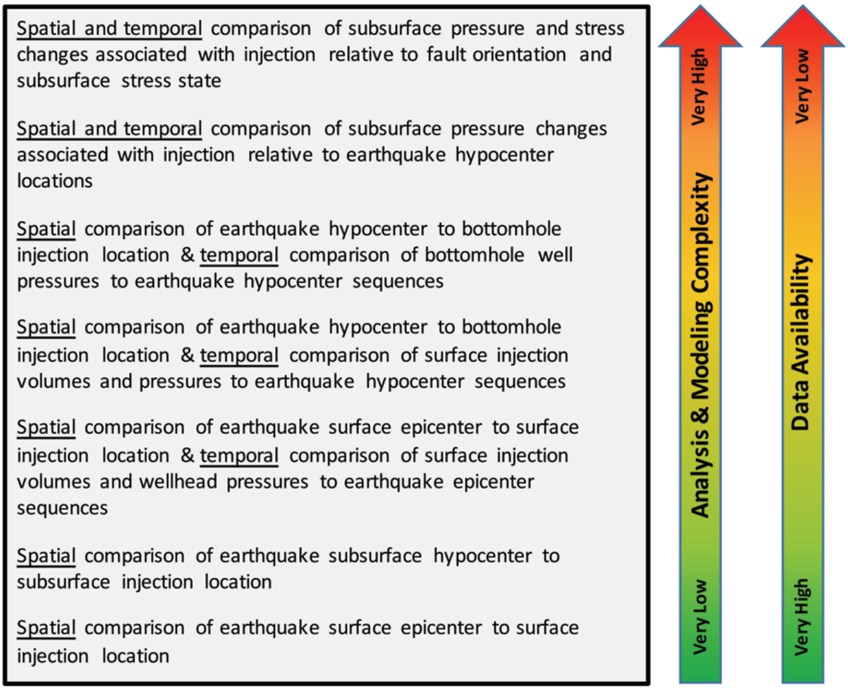

FIGURE 3-10 Illustration of statistical and physics-based modeling approaches to evaluate the potential for injection to induce earthquakes, reflecting that as modeling complexity increases, data availability decreases, and data uncertainty generally increases.
SOURCE: Groundwater Protection Council and Interstate Oil and Gas Compact Commission, 2015.

Statistical methods that consider temporal and spatial correlations of well surface locations and volumes are more common because available data may not address the subsurface physics. Further, the physics-based modeling approaches require more complicated computational approaches that are fundamentally challenged by lack of subsurface reservoir and fault characterization data, leading to substantial uncertainty in input data and the associated modeling results. Nonetheless, physics-based approaches improve understanding of the underlying physical processes, and can inform science-based mitigation of induced earthquakes (Groundwater Protection Council and Interstate Oil and Gas Compact Commission, 2015).

Mechanisms of both natural and induced earthquakes in Texas are not completely understood, and building physically-complete models to study them requires the integration of data that always will have irreducible uncertainties.

Understanding Progress in Texas: Advancing the Knowledge and Science

Recognizing the challenges and limitations associated with the various approaches to assess how and whether injection operations may be contributing to seismicity, appropriations House Bill 2 was passed by the Texas Legislature during the 84th Legislative Session in 2015. The bill awarded $4.47 million to The University of Texas at Austin for the purchase and deployment of seismic equipment, maintenance of the seismic network, and modeling of the reservoir behavior for systems of wells in the vicinity of faults. Due to the cross-disciplinary technical nature of the problem as illustrated in the previous discussion, the funding is supporting collaborative research relationships with other Texas universities, including Southern Methodist University and Texas A&M University. This effort is familiarly referred to as TexNet. In addition to TexNet, the University of Texas Bureau of Economic Geology (BEG) has created the Center for Integrated Seismicity Research, which is funded by the oil and gas industry to expand research of induced seismicity in Texas.

The current seismic network infrastructure is not sufficient to fully identify hypocenter depths of earthquakes in Texas. TexNet funding is intended for a more detailed seismic monitoring capability across Texas that is critical to assessing induced seismicity. This network design and installation (Figure 3-11) deploys temporary seismic monitoring stations and conducts site-specific assessments designed to enable monitoring, locating, and cataloging seismicity across Texas. It will be capable of detecting and locating earthquakes with magnitudes ≥M2.0 (compared to the historical threshold of M3.0). This additional capacity will improve investigations of ongoing earthquake sequences and cataloging seismicity across Texas.

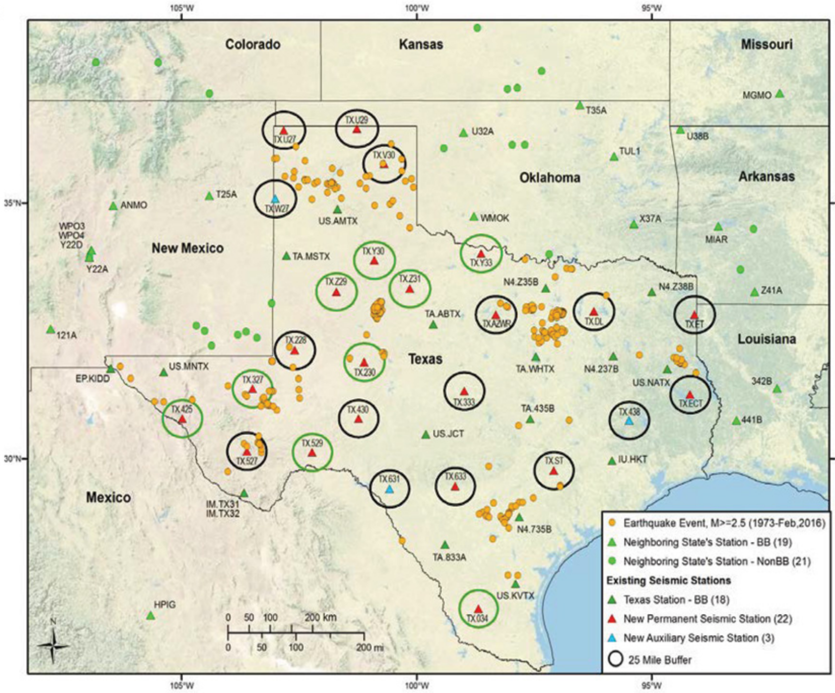

FIGURE 3-11 In 2015, the Texas Legislature provided funding for installation of the TexNet seismic monitoring system to improve statewide seismic monitoring capability by increasing the number of seismic stations in Texas from 18 to 43. Stations with green circles are currently being installed.
SOURCE: BEG, 2016.

Recognizing the cross-disciplinary nature of the problem, the legislative funding also provides for collaborative reservoir modeling studies to better understand the potential changes in subsurface stresses associated with disposal operations. TexNet research is focused on the pursuit of integrated research studies designed to improve the geologic characterization and reservoir description, and enhance understanding of the spatial distribution and source mechanisms of earthquakes statewide (see Figure 3-12).

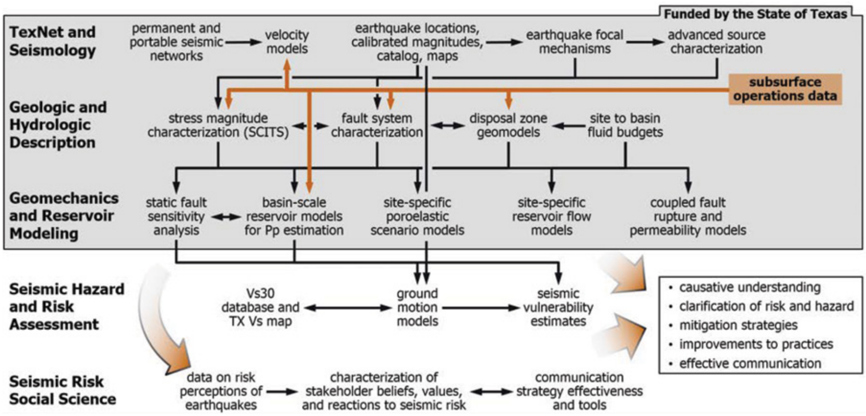

FIGURE 3-12 Schematic of the integrated seismicity, geologic-reservoir characterization, and reservoir-geomechanics studies being pursued with TexNet legislative funding as well as industry funding to the Center for Integrated Seismicity Research.
SOURCE: BEG, 2016.

The recent seismicity rate increase in Texas—in particular, its possible association with oil and gas operations and fluid disposal—has motivated closer examination of possible relationships between the two. A 2016 report to the Governor of Texas documented TexNet progress (Hennings et al., 2016), and the RRC has implemented new monitoring requirements (as discussed later in this report).

INDUCED EARTHQUAKES AND FLUID INJECTION

An issue related to induced earthquakes has been the difficulty of communicating the difference between hydraulic fracturing and fluid disposal as they relate to induced earthquakes. Although both processes are essential to shale well development, they are distinctly different and can affect subsurface faults in different ways. Before discussing the differences in the two processes, it is important to emphasize that within the United States and Texas, the majority of possibly induced felt earthquakes have been attributed to fluid disposal and not hydraulic fracturing. The following quote illustrates this point (see also Rubinstein and Mahani, 2015):

> (1) The process of hydraulic fracturing an oil or gas well, as presently implemented for shale gas recovery, does not pose a high risk for inducing felt seismic events;
>
> (2) Injection for disposal of waste water derived from energy technologies into the subsurface does pose some risk for induced seismicity, but very few events have been

documented over the past several decades relative to the large number of disposal wells in operation; and

(3) Carbon Capture and Storage (CCS), due to the large net volumes of injected fluids, may have potential for inducing larger seismic events.

(NRC, 2012).

Many shale oil and gas deposits in Texas have enough porosity to trap oil and gas but do not have enough connectivity of pore spaces, or permeability, to enable production at a profitable rate. A hydraulic fracture artificially increases the well production rate by extending a planar flow path into the formation that increases the effective contact area between the well and the formation. The volumes of fluids in a single hydraulic fracture treatment may be several orders of magnitude less than produced water volumes for some shale oil wells. Because produced formation water chemistry is often highly mineralized, the produced water must be disposed. For shale gas wells, the reverse may be true, and a small fraction of the water used for the fracture treatment may flow back. However, as for shale oil wells, produced water is often highly mineralized. Where possible, operators reuse produced water for hydraulic fracturing, thereby reducing the volumes of both fresh water needed for hydraulic fracturing and produced water to dispose.

The objective of hydraulic fracturing is to create a crack, known as a tensile failure, and to expand the crack into the shale formation away from the well. The crack parts the rock and creates only minimal changes in pore pressure; the pressure in the crack, however, must be above the formation pressure to propagate the fracture deep into the formation. The act of hydraulic fracturing frequently creates "microseismic" events as part of the process, with these events being less than approximately M1.0 to M2.0, nearly one order of magnitude or more below the level necessary to be felt at the surface (Warpinski, 2012).

If a pressurized hydraulic fracture intersects a sufficiently large fault or if the induced subsurface stress field changes due to hydraulic fracturing influence the stress field near a critically stressed fault, it may be possible to generate a surface felt earthquake sequence. However, this phenomenon appears to be limited in the United States. A small number of hydraulic fracturing operations worldwide have been suggested as likely causes of observed seismicity. Isolated reports of felt earthquakes associated with hydraulic fracturing have been reported in Ohio (Skoumal et al., 2015), Oklahoma (Holland, 2013), and western Canada (Atkinson et al., 2015). These examples illustrate the importance of assessing local geological conditions, *in situ* stresses, and location of faults in order to mitigate impacts, and they remain an active area of research.

In contrast, disposal of water produced from shale wells often is deliberately injected below the formation parting (fracturing) pressure into highly porous formations, such as limestone. In this case, the fluids can more easily flow through the highly permeable material and possibly deeper layers such as the basement where old faults may exist. The injected fluid is forced into pore space that is typically filled with saline water. Because water compressibility is very low, injection increases the formation pore pressure, and the pore pressure elevation penetrates radially into the formation away from the well. A single wastewater injection well typically can accommodate water from a number of producing wells, and the volume of fluids can be several orders of magnitude greater than a single hydraulic fracture. Many of these wells are known as "Class II" wells. They are wells for the injection of Class II fluids. These fluids are primarily brines (salt water) brought to the surface while producing oil and gas. Both the proximity to basement faults, and the large injection volumes, explain why felt earthquakes usually are associated with disposal wells rather than hydraulic fracturing.

To date, potentially induced earthquakes in Texas, felt at the surface, have been associated with fluid disposal in Class II disposal wells, not with the hydraulic fracturing process.

HAZARD AND RISK FROM TEXAS EARTHQUAKES

When assessing the impact of possible earthquakes, it is common to distinguish between two components. The first component deals exclusively with the earthquake magnitude, its probability of occurrence, and estimated ground motion. Within the United States, the U.S. Geological Survey has the responsibility for making earthquake hazard estimates. The most recent hazard assessment for the continental United States was completed in 2014 (Petersen et al., 2014).

The second component of the assessment of an earthquake's impact is quantification of how the predicted ground motions will affect buildings, infrastructure, and people in a particular region. In some contexts, this part of the analysis often is described as a risk analysis, and it considers possible consequences of an earthquake based on factors such as population density and property values. A moderate-sized earthquake such as the Alpine earthquake of 1995 will have little impact to life and property in a sparsely-populated region. Alternatively, the same earthquake in a highly-populated area, possibly with an inventory of buildings not designed to withstand earthquakes, can result in significant loss of life and damage, and would be considered as a high-risk event. In the case of earthquake hazard, quantification of strong ground motion is critical (see Figure 3-7).

Within the United States federal government, the Federal Emergency Management Administration (FEMA), working with the USGS, is responsible for risk assessment. The purpose of assessing both the possible financial and personal impacts of events based on the hazard analysis is to motivate planning for such events. This analysis can impact education, preparation, and other measures that might help mitigate possible earthquake impacts.

Since the first step in estimating the possible impacts of earthquakes is the hazard estimate, the documentation of ongoing seismicity provides initial information followed by a quantification of how seismic waves decay as a function of distance in particular areas. One TexNet goal is to refine the documentation of Texas seismicity, and the documentation of how seismic waves decay as they propagate away from earthquakes. Communication of the results of this and other efforts is one step to enhance public understanding of the need for earthquake hazard assessment that is critical to infrastructure, citizens, and the environment. A discussion of the concepts of hazard and risk of earthquakes as they are applied generally, and to induced earthquakes particularly, can be found in the 2015 report by the Ground Water Protection Council and Interstate Oil and Gas Compact Commission that investigates induced seismicity (substantial details related to both hazard and risk assessment for earthquakes can be found in Walters et al., 2015).

Based on recent possible linkages between fluid disposal and earthquakes, the USGS has embarked on an effort to investigate hazard assessment focused on induced earthquakes. The motivation for this work is the underlying assumption that if earthquakes are induced by the disposal of fluids, then this risk can be reduced by changing injection practices, and induced earthquakes should not be included in long-term hazard assessments associated with purely tectonic events. Recent earthquakes in Texas that are suspected of being induced have been included in recent USGS estimates (Petersen et al., 2016a). A discussion of assessment was published in a 2016 issue of the *Seismological Research Letters* professional journal, and discusses how the hazard assessment might impact risk determination in the central and eastern United States, including Texas (Petersen et al., 2016b).

ROLES OF THE RAILROAD COMMISSION OF TEXAS IN INDUCED EARTHQUAKE MITIGATION STRATEGIES

The Railroad Commission of Texas (RRC) has major regulatory responsibilities of Texas' oil and gas industries. Over time, its mission has evolved from regulating intrastate commerce dominated by railroads in the late nineteenth century to regulating oil and gas development, pipeline safety, mining, and alternative fuels.

To continue to improve underlying earthquake science, systematic research initiatives such as TexNet will be paramount. Ongoing research efforts, both academic and industrial, are key to informing the public, the Texas Legislature, and the RRC. As such, the Texas Legislature funded the TexNet program. In addition to scientific information, regulatory actions are necessary to help protect the public and the environment from detrimental effects arising from induced earthquakes.

Since the earthquake sequence in the Azle/Reno area in the Fort Worth Basin that began in the fall of 2013, the RRC has taken several actions regarding earthquakes that may be related to deep, subsurface water injections at fluid disposal wells. Subsequent to the 2013 activity, the RRC hired an induced-seismicity expert and amended existing rules for operating Class II wells. These rules require more stringent review of disposal wells that have occurred in the vicinity of historic earthquake locations, and clarified its authority to modify, amend, suspend or terminate a permit to inject into the subsurface, if the commission staff determines that it is possible that an earthquake was caused by active fluid injection operations.

The RRC also responded when a magnitude M4.0 earthquake occurred near Venus in Johnson County on May 7, 2015. This earthquake is the largest to date in the greater Dallas-Fort Worth metropolitan area.

REDUCING KNOWLEDGE GAPS IN TEXAS GEOLOGY AND SEISMICITY

This chapter has documented considerable scientific research pursued by academia, industry, and state and federal research institutions focused on induced seismicity. A broad number of disciplinary groups are critical to this work. Improved understanding of the role of fluid injection on inducing earthquakes will require exchanges of expertise, data, and models across multiple technical disciplines that include geology, seismology and geophysics, geomechanics, and reservoir engineering. Beyond technical cross-disciplinary collaboration, progress will require ongoing dialogue, effective communication, and continued collaboration across multiple parties with interests in shale development and its implications. A challenge and limitation regarding past data collection, analysis, and the archiving and curation of Texas geology and earthquake activity is that essential data is not easily accessible.

Future geologic and seismological research initiatives should develop improved and transparent approaches that seek to balance concerns surrounding data handling and sharing, and that promote sharing of data.

The large increase in usable seismicity data that will come from the TexNet implementation will be most meaningful when integrated with data sets including pressure, stress, mapped faults, and ground motion collected by different disciplines in various institutions.

Development of a common data platform and standardized data formats could enable various entities collecting data to contribute to better data integration. It also could facilitate interdisciplinary collaboration directed toward mitigation and avoidance of induced seismicity.

Access to data will enable research to develop improved data analysis tools. For example, improved event detection and extraction techniques rely on complex waveform correlation across multiple stations that may offer the opportunity to extract additional information from historic network data. Further, implementation of modern modeling techniques based on the reservoir, stress, and fault characterization will improve the basis for exploring the underlying physical models and improve methods for mitigating the impacts of induced earthquakes. These and other forward-looking focus areas have been incorporated into the TexNet program and motivate the value of its ongoing funding.

The TexNet goals address an integrated research portfolio that considers seismicity analysis, geologic characterization, fluid-flow modeling, and geomechanical analysis.

SUMMARY

The scientific knowledge base of Texas geology and earthquake activity is extensive. Research in this broad scientific field dates back over 100 years, and data collection and studies have been led by experts in the state's numerous large universities, private industry, and some nongovernmental groups. Considering that body of research and knowledge as a collective whole, and attempting to issue broad statements regarding its general adequacy in helping understand a given topic, is a daunting task.

One reason simply is the size of Texas. It is the nation's second-largest state; only Alaska covers more territory. For a frame of reference, its areal extent of 268,580 square miles makes it larger than the Colorado River Basin of the Southwestern United States, which covers large portions of seven U.S. states. The systematic and sustained collection of subsurface data across an area of this size, and the geologic heterogeneity that exists across Texas, represents a considerable challenge and undertaking. A great deal of scientific information has been collected and analyzed, and there have been many advances in this knowledge. Further studies will be necessary to develop a more detailed and sophisticated understanding of these large and complex systems.

Findings

The geology of Texas is highly complex, which inhibits clear understanding of the many geological faults across the state and their dynamics. There are significant differences across the state in the composition of the underlying geologic formations, strata, and subsurface geophysical processes. Texas' geology also is unique. It is interesting to note that in comparison to Oklahoma, for example, seismicity in Texas is substantially different. The ratio of the number of magnitude M3.0 earthquakes between Oklahoma and Texas is approximately 60 to 1.

- **Geologic faults are ubiquitous across Texas; these faults are poorly and incompletely characterized.**
- **The majority of known faults in the subsurface in Texas are stable and are not prone to generating earthquakes.**
- **There has been an increase in the rate of recorded seismicity in Texas over**

the last several years. Between 1975 and 2008 there were, on average, one to two earthquakes per year of magnitude greater than M3.0. Between 2008 and 2016, the rate increased to about 12 to 15 earthquakes per year on average.

- **Under certain unique geologic conditions, faults that are at or near critical stress may slip and produce an earthquake if nearby fluid injection alters the effective subsurface stresses acting on a fault.**
- **Mechanisms of both natural and induced earthquakes in Texas are not completely understood, and building physically-complete models to study them requires the integration of data that always will have irreducible uncertainties.**
- **To date, potentially induced earthquakes in Texas, felt at the surface, have been associated with fluid disposal in Class II disposal wells, not with the hydraulic fracturing process.**
- **The TexNet goals address an integrated research portfolio that considers seismicity analysis, geologic characterization, fluid-flow modeling, and geomechanical analysis.**

Recommendations

The historical record of seismicity in Texas is based on written records and sparse, sometimes limited, instrumental data. Available data indicates increased rates of seismicity in a limited geographic area over the last several years.

As specified in the language of Texas House Bill 2 of 2015, a program—referred to as TexNet—was initiated to provide additional resources to enhance geophysical monitoring across the state. Overseen by multiple universities in the state, research currently being conducted using TexNet funds is focused on understanding the potential relationships between subsurface injection of fluids related to oil and gas production and earthquakes in the vicinity of faults. These narrow, yet highly complex research goals cannot be accomplished without also performing more fundamental research tasks. In response to increased rates of seismicity in some areas, the Railroad Commission (RRC) of Texas has amended rules to address seismicity in oil and gas regions.

There is ongoing, vigorous research collaboration among academia, industry, and state regulatory agencies. Parties and initiatives include The University of Texas at Austin Bureau of Economic Geology Center for Induced Seismicity Research (CISR); the $4.7 million TexNet seismic monitoring program that includes collaborators from universities, federal and state governments, and industry; and States First, an induced seismicity workgroup initiative that is a multi-state and multi-agency collaborative effort. Improved understanding of potentially-induced seismicity will require these types of long-term, sustained, cross-disciplinary research efforts.

- **Future geologic and seismological research initiatives should develop**

improved and transparent approaches that seek to balance concerns surrounding data handling and sharing, and that promote sharing of data.

- **Development of a common data platform and standardized data formats could enable various entities collecting data to contribute to better data integration. It also could facilitate interdisciplinary collaboration directed toward mitigation and avoidance of induced seismicity.**

4

Land Resources

- Texas lands are almost entirely privately-owned. Shale development takes place largely on private lands, which generally are not sites of formal environmental impact studies.
- The few studies that have been conducted on erosion and soil contamination from oil and gas development in Texas indicate that well pad development has an increased potential for erosion, and that soil contamination is possible from oil and gas production.
- The vast number of new wells drilled in shale formations in Texas since 2007 have had substantial spatial impacts on the landscape.
- In many areas of Texas, there is little information regarding impacts of oil and gas activities on vegetative resources, agriculture, and wildlife and their habitats. No comprehensive and integrated assessment of the large-scale impact of shale development on Texas land resources has been conducted.
- Landowners in Texas who do not own the mineral rights associated with their property have very limited control over oil and gas operations.

This chapter describes the effects of shale development on Texas' land resources. Texas is unique in multiple respects: 1) it is vast in size and contains an array of distinct ecosystems that support an extraordinary degree of biodiversity; 2) the majority of land in Texas is privately held, and research of potential impacts on land and ecosystem resources has been limited due to access constraints associated with private land ownership; and 3) it has experienced the most dramatic increase in oil and gas drilling and production of any state in the nation over the last decade. An important theme of this chapter is that there is very limited scientific information in the peer-reviewed literature about the impacts of oil and gas drilling on land resources in Texas. Of the existing studies, nearly all of them have focused on traditional exploration and production, not the horizontal drilling and hydraulic fracturing techniques that take place in shale. This theme and reality of the state of science knowledge runs through this chapter, and forms the basis for recommendations for future study.

This chapter discusses the impacts of expanded oil and gas drilling on land resources in Texas. It focuses first on ecosystem impacts: 1) soil erosion and contamination; 2) landscape fragmentation and habitat loss; and 3) effects on native vegetation. Secondly, it discusses issues of interest to landowners. A third section of the chapter addresses accessibility and availability of data on surface land impacts. The chapter concludes with findings and recommendations for further study that can help better understand these phenomena.

TEXAS LAND RESOURCES

Texas is enormous, and the state has a tremendous diversity of ecosystems, biomes, and plant species. The state covers 266,807 square miles, has dramatic variations in climate and landscapes, and is located at a crossroads of eastern and western as well as northern temperate and southern subtropical, habitats. Average annual rainfall ranges from eight inches in the deserts of West Texas to 56 inches in the swampy forests of East Texas (Texas Parks and Wildlife Department, 2017a). A range of markedly different ecosystems are found across the state: mountains and deserts in West Texas, humid swamps and estuaries along the Gulf Coast, piney woods in East Texas, and mixed oak-juniper forests in the Edwards Plateau of Central Texas.

Texas hosts an impressive degree of biodiversity; Texas ranks second in number of species only to California, with 6,273 species of plants and animals found within its borders (Stein, 2002). Because Texas is a meeting place of unique habitats, it contains a blend of eastern and western species and supports more bird species—540 (Texas State Historical Association, 2017)—and reptiles—149 (Stein, 2012)—than any other state. It also has a high level of endemism (species found exclusively in one state), with 340 endemic species, placing it third behind California and Hawaii (Stein, 2012). Based on its diverse biophysical characteristics, the state is divided into ten "ecoregions" that support unique communities of plants and animals (Figure 4-1).

Texas hosts an extraordinary degree of biodiversity, due to the diverse topographic, geologic, and climatic conditions across the state.

FIGURE 4-1 Texas ecoregions.
SOURCE: Texas Parks and Wildlife Department, 2017a.

A number of the species found in Texas are considered to be at risk of extinction according to NatureServe, a nonprofit organization that collects and analyzes scientific information about biodiversity from all 50 states (Stein, 2012). Texas ranks in the top 10 states for the most species of mammals, birds, reptiles, amphibians, and freshwater fish considered at-risk (Stein, 2012). It ranks 11th overall for at-risk species. Almost all the at-risk species have experienced population declines because of the loss and fragmentation of their habitats (Stein, 2012).

Texas lands are almost entirely privately-owned, with approximately 95 percent of the land in private ownership (Texas A&M Institute of Renewable Natural Resources, 2012). Within the state, 142 million acres—84 percent of the total land area—are farms, ranches, and forests ("working lands"), which provide an economic impact of over $100 billion annually (Texas Department of Agriculture, 2017). Texas leads the nation in cattle, cotton, hay, sheep, goats, and mohair production, and also has the country's highest valued farm real estate (ibid.). Texas' privately-owned agricultural and range lands provide vital habitat for the state's plants and animals.

Texas lands are almost entirely privately-owned. Shale development takes place largely on private lands, which generally are not sites of formal environmental impact studies.

OIL AND GAS DEVELOPMENT IN TEXAS

Oil and gas exploration and production is only one development activity that has affected the Texas landscape over the last century. The state has lost a sizeable amount of agricultural lands, forests, and grasslands to urbanization that has accompanied population growth. Between 1997 and 2012, for example, 1.1 million acres of farms, ranches, and forests were lost to urban and suburban development as the population of Texas grew from 19 million to 26 million (Texas A&M Institute of Renewable Natural Resources, 2012).

The landscape impacts described in this chapter are not unique to shale development; rather, they are features of oil and gas development more generally, which has been occurring in Texas since the first oil well was drilled in 1866 (Texas State Historical Association, 2017). Nonetheless, recent expansion in oil and gas drilling activities in Texas has intensified these impacts on the landscape.

Texas has experienced a dramatic expansion of oil and gas drilling since 2007 due to the technological advances that made it possible to develop the state's abundant shale resources. Figure 4-2 shows that the number of drilling permits issued each year in the state from 1980 to 2015. Statewide, the number of drilling permits jumped from 16,914 in 2005 to almost 26,000 in 2014 before dropping off in 2015, due to low oil and gas prices (RRC, 2016a).

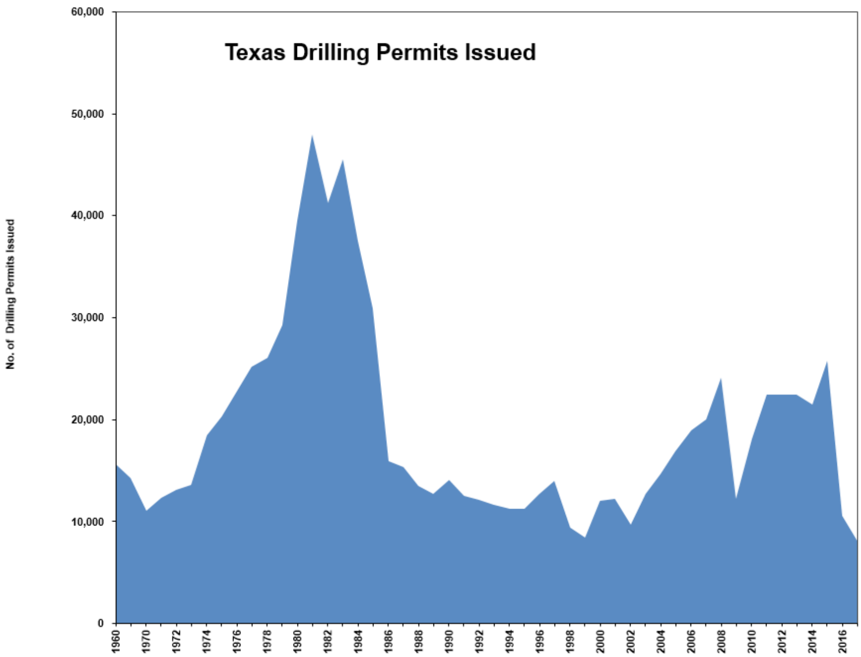

FIGURE 4-2 Texas Drilling Permits Issued, 1980-2015.
SOURCE: RRC, 2016b.

Oil and gas operations are ubiquitous in Texas. Oil and natural gas are produced in 215 out of Texas' 254 counties (RRC, 2016). The spatial extent of oil and gas drilling in Texas is apparent from this 2015 map of active oil and gas wells (Figure 4-3).

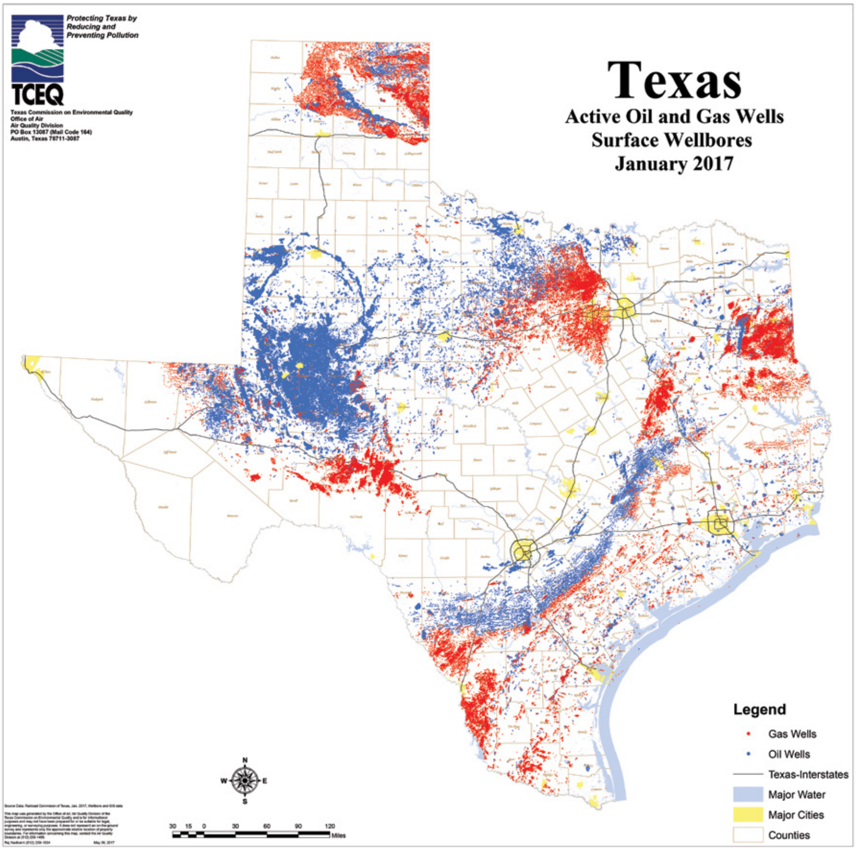

FIGURE 4-3 Active oil and gas wells in Texas, January 2017.
SOURCE: Raj B. Nadkarni, GISP, TCEQ, Office of Air, Air Quality Division, 2017.

Oil and gas operations require land clearing and infrastructure development, including roads, pipelines, equipment, and well pad construction. The various construction and operating activities associated with oil and gas operations could affect a variety of ecosystem services by causing soil erosion and contamination, landscape fragmentation and habitat loss, and changes to the native vegetation. These potential impacts also affect landowners: the surface owners where drilling and production activities take place as well as neighboring landowners. Figure 4-4 shows satellite images of the pad locations added to the land surface between 2002 and 2015. The images also show other new features, including roads and pipelines.

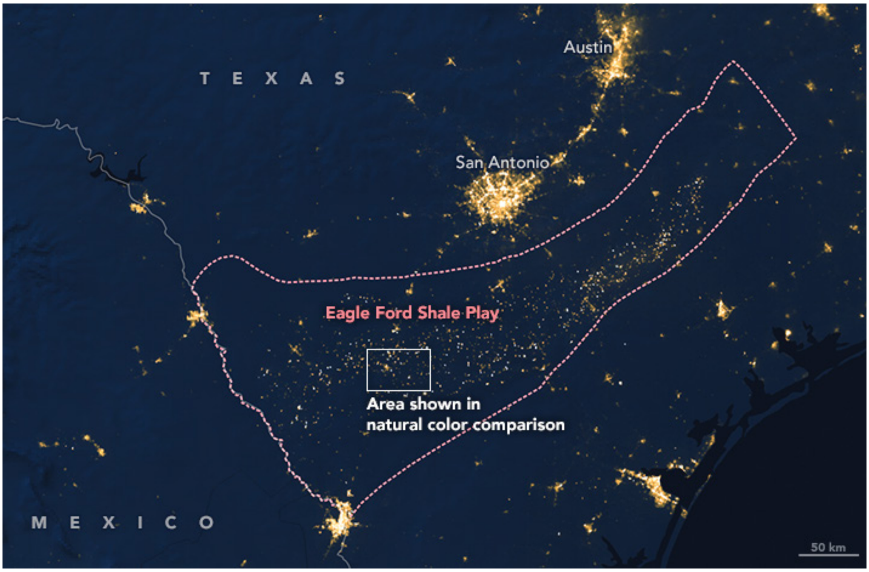

FIGURE 4-4 Nighttime satellite imagery of light from oil and gas infrastructure in South Texas, 2016.
SOURCE: National Aeronautical and Space Administration.

ECOSYSTEM IMPACTS

The drilling upturn experienced in Texas since 2007 occurred in many parts of North America. Roughly 50,000 new wells per year were drilled from 2000 to 2014 in Central North America, resulting in the transformation of millions of hectares of the Great Plains (Allred et al., 2015). Although oil and gas have been produced in the United States for more than a century, and shale drilling operations increased exponentially after 2007, few studies have been conducted to quantify the associated environmental impacts (Souther et al., 2014). Most of the landscape and ecosystems research conducted in Texas addresses effects associated with traditional oil and gas development, not shale production. There is a broad range of possible effects of these activities, including soil erosion; effects on water temperature, pH and other quality factors; reduced flow and increased siltation in streams; habitat loss and fragmentation; changes in native vegetation; and air, noise, and light pollution. The cumulative effects of these types of changes may represent threats to native plants and animals. The relatively small number of relevant studies and lack of reliable, quantified data make the magnitude of the impacts difficult to assess.

Soil Erosion and Contamination

There are few data on impacts to landscapes and soil resources in Texas from oil and gas development. A handful of small-scale studies suggest that increased erosion is associated with clearing land for well pads (Williams et al., 2008; McBroom et al., 2012). Erosion may alter the hydrology of streams and negatively affect water quality. Gas well sites in North Central Texas had up to 49 times higher levels of erosion than the typical level for undisturbed rangelands (Williams et al., 2008). In East Texas, gas well sites had significantly more runoff than clear-cut forestry operations (McBroom et al., 2012). One of the only studies of the land impacts of shale development documented 51 percent increased potential for soil loss on disturbed sites because of higher surface runoff and greater wind erodibility in La Salle County in the Eagle Ford Shale play (Pierre et al., 2015).

Based on the small number of studies available, it appears that well pad development is indicative of increased potential for erosion. The erosion impacts of pipelines, on the other hand, has not been documented. Erosion caused by roads constructed in shale plays has not been studied either, but the effects are likely similar to erosion caused by road construction in other contexts. There have been no peer-reviewed studies of erosion from well development at large spatial scales, so no data exist on large-scale impacts of erosion from shale development.

With respect to soil contamination from oil and gas drilling, one study indicated that 16 of 18 historic oil pad sites on Padre Island had contamination agents present (heavy metals, sodium, elevated salinity, pH, or hydrocarbons), but the contaminant levels did not pose immediate threats (Carls et al., 1995). In West Texas, sites that experienced on-site disposal of drilling fluids in reserve pits showed significant increases in soluble salt concentrations and other contaminants (McFarland et al., 1987). Cumulatively, these studies indicate that contamination of soils is possible from oil and gas production, but its extent has not been well-characterized across regions, soil types, or oil and gas plays.

The few studies that have been conducted on erosion and soil contamination from oil and gas development in Texas indicate that well pad development has an increased potential for erosion, and that soil contamination is possible from oil and gas production.

Landscape Fragmentation and Habitat Loss

The spatial impacts of shale development on the Texas landscape are substantial. The actual footprint of the well pads, pipelines, roads, and other infrastructure, while significant, is smaller than the ecological footprint. That is, the fragmentation of habitats caused by oil and gas development affects species and the ecosystem beyond the direct loss of vegetation.

On average, 1.5 to 3.1 hectares of vegetation are cleared for every well pad

(Entrekin et al., 2011). Another study found that each new well results in 3 to 7 acres "consumed" (Brittingham et al., 2014). The Railroad Commission of Texas (RRC) issued permits for 26,000 wells in 2014. Assuming that each one required a minimum of 1.5 hectares (3.7 acres) for the well pad, as many as 96,000 acres were covered by new wells in 2014 alone. However, many well pads are constructed for multiple wells, which reduces the per-well footprint. For example, in La Salle County in the Eagle Ford shale region there was a period during which 23 percent of the well pads were for multiple wells (Pierre et al., 2015). In addition, and in a point worth emphasizing, horizontal wells affect the surface less than the number of vertical wells that would be required to reach the resource. Compared to biofuels production and surface mining for oil sands, conventional oil and gas drilling has less impact on land fragmentation per unit of energy produced (Yeh et al., 2010). Well pads that support multiple wells reduce fragmentation further.

The vast number of new wells drilled in shale formations in Texas since 2007 have had substantial spatial impacts on the landscape. However, horizontal wells have a smaller impact than the equivalent number of vertical wells would have had. When operators use a single well pad for multiple wells, surface impacts are significantly reduced.

The spatial area cleared for pipelines and other infrastructure often far exceeds that of the well pads (Slonecker et al., 2012). In La Salle County, pipeline construction was the dominant landscape change feature, followed by drilling and injection pads, when development began in the Eagle Ford formation (Pierre et al., 2015). As a result of the pipelines, species' core habitat areas decreased 8.7 percent; patches, edges, and perforated areas increased. Overall habitat fragmentation increased in the county 62 percent (Pierre et al., 2015). Similarly, in the Barnett Shale, patch, edge, and small core landscape conditions increased with development, especially in areas where roads crossed. The severity of the impacts varied depending on the intensity of the drilling operation (Pradhananga, 2014).

Fragmentation generally creates more "edge" habitat that benefits common generalist species at the expense of rare and vulnerable species (Allred et al., 2015). Fragmentation also may compromise migratory pathways and habitat connectivity and lead to increased wildlife mortality. It can create conduits for invasive species that displace native species and deleteriously affect critical ecological functions (Fahrig, 2003; Ries et al., 2004; Souther et al., 2014; Allred et al., 2015).

These impacts also negatively affect numerous ecosystem services that are critical for human well-being, including Net Primary Production (NPP). NPP is the amount of atmospheric carbon converted by plants into biomass and it is a fundamentally important life-sustaining ecosystem service. Rapid oil and gas development between 2000 and 2012 in Texas and other select locations in the Great Plains substantially impacted biomass production because of the large amounts of vegetation removed to construct oil pads, roads, pipelines, and other infrastructure. It has been estimated that vegetation removal associated with oil and gas development resulted in ~10 Tg (10 million metric tons) loss of dry biomass across Central North

America (Figure 4-5). The loss of biomass in rangelands was estimated to equate to about 5 million animal unit months (one animal unit is the amount of forage required for one mature cow for one month), while the biomass loss in croplands was estimated to exceed 120 million bushels of wheat (Allred et al., 2012). These losses are likely to be long-lasting because new drilling has outpaced reclamation of previously drilled areas.

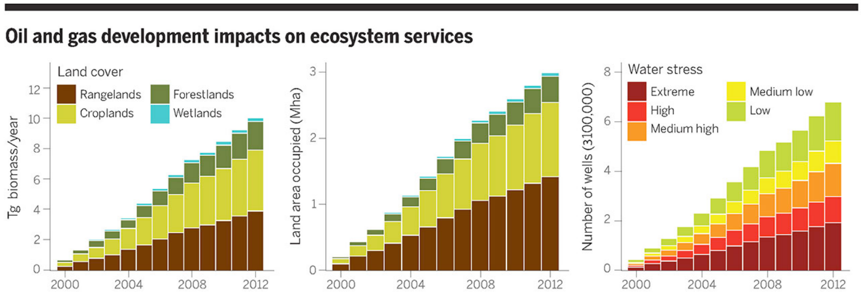

FIGURE 4-5 Cumulative impacts of oil and gas development on ecosystem services in Central North America, 2000 to 2012: (left) reduction in biomass; (middle) land area occupied; and (right) number of wells in water-stressed regions.
SOURCE: Allred et al., 2015.

Despite these increasingly apparent impacts of extensive oil and gas development on rangelands, efforts to more precisely quantify them are stymied by gaps in the knowledge base of landscape and ecosystems (Souther et al., 2014). Those gaps associated with resources provided by rangelands include: 1) baseline biota in areas that are to be developed; 2) effects on forage supply; 3) effects on surface water drainage and filtration processes; and 4) effective tools to restore oil and gas impacted ecosystems and habitats (Kreuter et al., 2016). Another challenge in quantifying these effects is the lack of an integrated evaluation framework that systematically identifies interactions and the aggregation of effects (Kreuter et al., 2016).

The handful of published studies on fragmentation and habitat loss indicate that ecosystem fragmentation clearly does occur in shale plays, and the satellite imagery in Figure 4-4 illustrates the fragmentation. Fragmentation and habitat loss from oil and gas development can be quantified in Texas, but the corresponding *effects* on most wildlife species—impacts on populations of species and the health of their habitats—are largely unknown. Environmental impacts may be difficult to assess on private land. Some of these studies have been conducted on public lands, such as pipeline or electric transmission rights of way. Nonetheless, given that the vast majority of Texas lands are privately-owned, scientists would be well advised to consider monitoring and evaluation opportunities there as well.

Baseline land and habitat conditions at the oil and gas play level should be characterized, and changes to wildlife populations and vegetation should be tracked over time where there are opportunities on both private and public lands.

This chapter has noted the relative lack of underlying science information on impacts to land and species in Texas of shale development activities. Two species that were once candidates for listing under the federal Endangered Species Act have been studied in detail, however (see Texas Parks and Wildlife Department, 2017b). The following sections discuss threats to and status of the Dunes Sagebrush Lizard and Lesser Prairie Chicken and current initiatives to address threats to those species.

The most comprehensive information on species-specific impacts has been compiled for the Dunes Sagebrush Lizard and Lesser Prairie Chicken, with extensive studies of changes to their habitats and their life cycles and requirements. Both species are covered by voluntary conservation plans overseen by state agencies.

Dunes Sagebrush Lizard

The Dunes Sagebrush Lizard (*Sceloporus arenicolus*) is a small spiny lizard that eats insects and inhabits blowouts in shinnery oak sand dune systems of Southeast New Mexico and four Texas counties that overlie the Permian Basin. Clearing of shinnery oak for cattle grazing and oil and gas drilling is the main threat to the species (Smolensky and Fitzgerald, 2011; Leavitt and Fitzgerald, 2013). The U.S. Fish and Wildlife Service (USFWS) is the federal agency that administers the Endangered Species Act for terrestrial species. In December 2010, USFWS proposed listing the Dunes Sagebrush Lizard as endangered. This designation would have made it illegal to carry out any activity that would result in harm to the species or its habitat. To avert the need for listing, the Texas Legislature created an Interagency Task Force of Economic Growth and Endangered Species to formulate a plan for a Candidate Conservation Agreement with Assurances (CCAA). CCAAs are regulatory mechanisms by which landowners can agree to voluntarily conserve habitat for a species in exchange for assurances from the government that they will not be subject to additional land use restrictions if the species is eventually listed (USFWS, 2016a).

The CCAA for the Dunes Sagebrush Lizard, called the Texas Conservation Plan, includes a set of best management practices designed to minimize oil and gas development impacts to Dunes Sagebrush Lizard habitat (USFWS et al., 2011). These include use of existing infrastructure and previously disturbed sites for development to minimize new disturbance areas and restriction of land disturbance to the fall and winter, when the lizards are less active. Under Texas Conservation Plan agreements, oil and gas developers pay $4 per acre per year to fund oversight, monitoring, and Dunes Sagebrush Lizard research to inform adaptive management decisions. Citing the comprehensive nature of management practices in the Texas

Conservation Plan, and the fact that over 240,000 acres of habitat were enrolled, the USFWS withdrew its proposal to list the species in 2012 (U.S. Department of the Interior, 2012).

As of the end of 2015, approximately 55 percent of the total amount of Dunes Sagebrush Lizard habitat in West Texas was enrolled in the Texas Conservation Plan (Texas Comptroller of Public Accounts, 2016). New enrollment was low in 2015; only 300 acres were enrolled that year. Few habitat restoration programs have been conducted, however; rather, mitigation dollars have been directed mostly to research (Texas Comptroller of Public Accounts, 2016). It is difficult to assess the overall effectiveness of the Texas Conservation Plan in part because information about participants is confidential, pursuant to state law.

Lesser Prairie Chicken

The Lesser Prairie Chicken (*Tympanuchus pallidicinctus*) is a grouse species whose preferred habitat consists of native short-grass and mixed-grass prairies with a shrub component dominated by sand sagebrush or shinnery oak (Taylor and Guthery, 1980; Giesen, 1998). The species' range extends from Western Texas and Eastern New Mexico into Western Oklahoma, Eastern Colorado, and Western Kansas. The Lesser Prairie Chicken has experienced significant population declines over the last century, due to the loss and fragmentation of its habitat. It currently occupies about 17 percent of its historic range. The USFWS listed the Lesser Prairie Chicken as threatened in 2014 and identified further habitat fragmentation from energy development as a primary threat to the species (Federal Register, 2014).

In 2012, the parks and game departments of the five states that are home to the Lesser Prairie Chicken—Texas, Kansas, New Mexico, Oklahoma, and Colorado—created a partnership to craft a conservation plan for the species. They formulated the Lesser Prairie Chicken Range-wide Conservation Plan, which is similar to the Texas Conservation Plan in several respects (Van Pelt et al., 2013; see also Texas Parks and Wildlife Department, 2012). It is a voluntary plan under which landowners and other participants (e.g., oil and gas developers) may enroll and agree to implement various best management practices that avoid or minimize impacts on Lesser Prairie Chicken habitat. Oil and gas developers agree to strive to locate their operations outside of high quality habitat, and to utilize existing infrastructure where possible. They also pay an enrollment fee, which is calculated in accordance with the number of acres that will be impacted. The states use these funds to carry out monitoring and management programs and to pay for temporary and permanent conservation easements on high-quality Lesser Prairie Chicken habitat.

The Texas Parks and Wildlife Department (TPWD) is a member of the Western Association of Fish and Wildlife Agencies (WAFWA) and participated in the formulation of the Range-wide Conservation Plan (RWP) for the Lesser Prairie Chicken. TPWD provides technical assistance to landowners and oil and gas companies that desire to participate in the plan, and it administers a CCAA for the Lesser Prairie Chicken by issuing certificates of inclusion to participating entities. The CCAA includes a list of recommended land management practices (e.g., native grass restoration, prescribed burning) to enhance chicken habitat and recommendations for avoiding or minimizing habitat impacts (e.g., avoiding drilling in habitat). The chicken population has declined since the RWP was finalized, due to a range of factors, including regional drought, but in 2016 it experienced an increase. In July of 2016, and in accordance with a court order, the Lesser Prairie Chicken was removed from the list of threatened and endangered species (USFWS, 2016b).

Finally, the Texas Comptroller is overseeing research on the status of and threats to a number of rare species. The research may provide information relevant to the impact of oil and gas development on the species being studied. The studies will be released as they are completed over the next two years. Oil and gas drilling generally, and shale development specifically, have increased habitat fragmentation in Texas. There are, however, very few studies on the *impact* of fragmentation from oil and gas on species populations and the health of habitats.

The effectiveness of voluntary programs to conserve at-risk species should be studied, along with options for incentives to conserve at-risk species and reduce effects on land resources by oil and gas development activities.

Effects on Native Vegetation

Despite the extensive network of pipelines and the large number of well pads across Texas, almost no information on the effects of oil and gas infrastructure development on vegetative communities exists. One study indicated that roads and pipeline rights of way are vectors for exotic grass invasions and support near-monoculture stands of exotic grasses (Goertz, 2013). Another study indicated that non-native grasses cover historic pad sites at a higher concentration than in the adjacent landscape, but the invasion effects were limited to within 60 meters of the well pads (Cobb et al., 2016). Additional research will be necessary for more detailed understanding of these relationships.

A few studies have been carried out on restoration initiatives. For example, one study in the Eagle Ford along a pipeline indicated that various seeding techniques may be successfully used to restore native plants on three sites (Pawelek et al., 2015). Similarly, native seed mixes were successfully used to reclaim historic pad sites in South Texas, even with continuous livestock grazing (Falk et al., 2017). These studies indicate that native seeds may be successfully used to restore impacted areas. However, there is no research on long-term performance of the restored sites or on restoration projects outside of South Texas and the Eagle Ford Shale.

ISSUES FOR LANDOWNERS

In addition to ecosystem impacts, oil and gas development affects landowners by reducing the aesthetic value of their property and, sometimes, their property values. Mineral rights are a severable interest in real estate property that can be reserved or conveyed to third parties (Martin and Kramer, 2016), and ownership of the mineral estate is accompanied by an implied easement to enter and use as much of the surface estate as is reasonably necessary for the extraction of minerals from the tract (Sun Oil v. Whitaker). Consequently, the surface of a property owned by a single entity may become subject to the rights of several mineral owners to use the surface for oil and gas exploration. This right has been described as including "the legal privilege to use the surface in a way that interferes with the surface owner's use of the land and that significantly damages the surface, without the legal obligation to make any compensation whatsoever" (Smith, 2008).

Similar rights to access and use the surface estate can be granted by the terms of an oil and gas lease executed by a mineral owner. When rights to use the surface for oil and gas exploration are granted under the terms of a lease, these rights will define the scope of the operator's permitted use of the surface, but only to the extent they differ from the scope of the implied easement under common law (Martin and Kramer, 2016). The typical rights of surface use granted by an oil and gas lease include the right to clear land, drill wells, and build pipelines, roads, and facilities to support development operations. Unless otherwise restricted within the language of the lease contract, it is also considered reasonable for the operator to construct compressor stations, processing facilities, water impoundments, and even temporary employee housing on the property, so long as these facilities benefit production from the same lease or lands pooled therewith.

In Texas, the implied easement held by the mineral lessee to reasonable use of the surface is limited by the "accommodation doctrine," first established in the Texas Supreme Court's 1971 decision in Getty Oil Co. v. Jones. The case dealt with a surface owner whose existing pivot irrigation system was blocked by a mineral lessee's subsequent construction of two oil wells on the property. In its ruling, the Texas Supreme Court required application of the accommodation doctrine "where there is an existing use by the surface owner which would be otherwise precluded or impaired, and where under the established practices in the industry there are alternatives available to the lessee whereby the minerals can be recovered." In *Getty*, this meant requiring the mineral lessee to lower the profile of its well pumps to allow the surface owner's irrigation system to function.

In an indication of its limited scope, only a handful of Texas cases have applied the accommodation doctrine when presented with the opportunity. The surface owner bears the burden of proving the lessee's actions preclude or substantially impair existing surface use (Davis v. Devon Energy Prod. Co.), and the surface owner must also demonstrate that reasonable alternatives are available to the lessee on the same premises (Merriman v. XTO Energy, Inc.).

When surface owners hold little or no interest in the mineral estate beneath the property, their ability to enforce surface protections on an oil and gas operator will be dependent upon the generosity of owners of the mineral interest in the same tract. Because these severed mineral owners often have no incentive or connection to the surface property, they are unlikely to extend a helping hand to the surface owner—especially if it may require the trading away of financial benefits under the oil and gas lease (Kulander, 2002). As mentioned above, remedies available under the accommodation doctrine and similar common law protections against surface damages, trespass, and nuisance have been severely curtailed by the courts. Surface owners must bring suit within two years from when the damage occurs or risk losing their claim, even when the nature of the damage prevents its discovery until a much later time. Surface owners who discover property damage after the two-year limitations period has expired are left without any legal remedy, even in the case of continuing environmental contamination to the surface and groundwater. The Texas Supreme Court ruled recently on a suit involving soil and probable groundwater contamination in ExxonMobil Corp. v. Lazy R Ranch, L.P., et al., Docket No. 15-0270 (February 24, 2017). The court held that the ranch could not sue ExxonMobil for damages after the statute of limitations expired, but it did not reach the question of whether injunctive relief would be appropriate to compel the operator to clean up the contamination.

Of course, in cases in which the mineral rights and the surface rights are owned by the same entity, the surface owner has considerable leverage over the operator's practices. Over 2.1 million acres of surface and minerals are managed by University Lands for the University of Texas System and Texas A&M University System. Revenues from the leases constitute the Permanent University Fund, which supports twenty academic institutions in the state. The oil and gas lease for operations on university lands includes requirements for the operator to restore the surface after operations cease to its original condition. The lease also requires that the operator prevent pollution and consult with University Lands on its water plan. All pits must be properly filled, equipment removed, and no wells may be drilled within 300 feet of a residence or barn (University Lands Lease).

Landowners in Texas who do not own the mineral rights associated with their property have very limited control over oil and gas operations.

Surface damage statutes in one form or another have been adopted in the vast majority of states containing active exploration of oil and gas shale deposits (Martin and Kramer, 2011). These include major shale development areas such as the Bakken Shale in North Dakota and Montana, the portion of the Permian Basin within New Mexico, the Niobrara Shale in Colorado and Wyoming, and the Marcellus Shale in West Virginia and Pennsylvania. Notably absent from this list is Texas, which contains the Barnett Shale, Eagle Ford Shale, and the remainder of the Permian Basin. However, the enforcement of surface damage acts in other producing states has demonstrated that statutes protecting surface owners have no demonstrable impact upon mineral development.

The purpose of these statutory protections is to provide prior notice, reasonable compensation, and other protections to surface owners, in particular those with no mineral rights or bargaining power. The laws are meant to reimburse the surface owner for lost value, but they stop short of granting injunctive remedies that would forestall the operator's access to the property for exploration purposes.

Surface damage acts also have the effect of providing a predictable framework for both the surface owner and the operator. This allows operators to accurately estimate costs prior to the commencement of operations and streamline their budgeting process. For the surface owner, it decreases the anxiety associated with the operator's entry upon the property and presents a better opportunity for agreeable relations with the operator. In turn, this reduction of animosity between the parties mitigates associated legal fees and the burden upon the courts to adjudicate disputes.

Most states where development of shale resources is occurring have a surface damage act in place to protect the rights of landowners who do not own the mineral rights associated with their property. In Texas, if the surface owner controls any portion of the mineral rights, the owner may be able to use contractual provisions to negotiate with the operator and resolve disputes.

In addition, if the owner discovers damages caused by the operator within the statute of limitations time frame—two years—the tort/legal system may provide relief. Damages for the landowner are capped at the value of the damaged property and do not cover the actual cost of remediation.

Advantages and disadvantages of adopting a surface damages act to address the gaps in legal protection for landowners who do not own the minerals associated with their property should be evaluated.

ACCESSIBILITY AND AVAILABILITY OF DATA

The prior discussion of the ecosystem impacts of erosion and contamination, habitat loss and fragmentation, effects on native vegetation, and issues for landowners points to a clear initial conclusion: the recent upturn in shale development has altered the use of Texas land in significant ways. However, there is a dearth of knowledge about the impacts of oil and gas development, including shale development, on the state's land resources. The tangible effects of development are poorly studied. Impacts on wildlife species vary, depending on the species and its habitat requirements. The effect on land use for ranching and farming, and land values, are poorly documented. Finally, the long-term and cumulative environmental effects on land resources have not been sufficiently studied.

Information about the environmental impacts of oil and gas production resides in multiple datasets held and managed by different state and federal agencies. The

RRC bears primary responsibility for regulating activities at oil and gas wells that use hydraulic fracturing and directional drilling at shale locations (as well as their associated brine, water, and disposal facilities). RRC Rule 8 currently requires reports of spills or environmental damage caused to surface properties by oil and gas operations if they may cause pollution to surface or subsurface waters of the state. If that release results from a fire, leak, spill, or break, RRC Rule 10 dictates that the operator must report to the local RRC office immediately and then provide a subsequent letter detailing the circumstances and amount of the release. According to RRC Rule 91, the operator then must comply with RRC requirements to remediate the spill, and those obligations vary based on whether the spill or contamination occurred in a sensitive or non-sensitive area.

This information, which is vital for assessing surface impacts of broad shale development in Texas, has many important gaps. First, these data are currently used to assess the adequacy of spill responses and remediation at the local site, and the information remains at the local RRC office. Although the RRC maintains a comprehensive Geographic Information System (GIS) database that tracks active and inactive oil and gas wells, plugged and inactive sites, brine and disposal facilities, and dry and abandoned wells, it does not provide any dataset or display for spill reports, remediation, or disrupted land use.

Second, the RRC's dataset only includes information about substances and operations that fall under its jurisdiction. As a result, other aspects of shale development regulated by other agencies are not synthesized and compared with datasets compiled by the RRC. For example, the Texas Commission on Environmental Quality's (TCEQ) requirements for releases, emissions, and disposal of non-petroleum materials that constitute solid or hazardous waste, air or water pollutants, or reportable substances is separate from the RRC's mandate. Third, available data focus on current operations or recently plugged and abandoned wells. The vast swings in operational capacity caused by the role of shale wells as a swing producer means that wells that come on or go off production quickly can generate fragmented and incomplete data reports to state and federal agencies. Rapid swings in oil prices caused by shale production's variable capacity also raise the risk of more abandoned and orphaned well sites.

The potential value of a broader set of data extends beyond the gaps between state agency reports and records. Federal agencies also receive reports and information on shale operations. For example, the U.S. Environmental Protection Agency (EPA) receives information on state regulatory programs that manage hazardous wastes that fall outside the exemption provided for exploration and production wastes.

These gaps may have caused, and be causing, missed opportunities. For example, because regulators and operators in general have lacked information about potential increased efficiency from consolidating production at under-used production sites, more land space than necessary to efficiently produce from shale formations may have been affected. A larger resultant footprint of operations may have contributed to missed opportunities for reducing potential impacts to protected species and vulnerable ecosystems.

Data on environmental impacts of oil and gas development reside in several different state and federal agencies, and there is not a single database, readily searchable and available online, that integrates the data across different entities.

The existing, nonproprietary information about land impacts of shale development that is collected and evaluated by multiple state and federal agencies should be assembled and made available online to the public.

Shale development is proceeding apace across the state and will continue to do so. Shale development is poised to intensify, especially in the Permian Basin, given recent major discoveries. Along with the many economic benefits that this development will provide, there are opportunities to better understand large-scale impacts of oil and gas development on the landscape. At most shale development sites across Texas, restoration of land and vegetative resources is yet to be done; years or decades from now, large amounts of land resources will be potential sites for a range of restoration activities. Gaining experience with restoration, acquiring better knowledge of restoration outcomes, and learning more about pros and cons of restoration options, will serve the state well in the future when making choices of land resource restoration.

SUMMARY

Energy resource development and extraction activities date back many decades in Texas. The majority of land in Texas is privately held, and research of potential impacts on land and ecosystem resources has been limited due to access constraints associated with private land ownership. Some of the more thorough studies have focused on species that were considered for listing as threatened or endangered under the federal Endangered Species Act. Among other things, this limited knowledge base makes it difficult for Texas scientists to identify a baseline of land and ecosystem conditions, and trends by which current and future impacts might be measured.

Below are findings and recommendations to help expand the scientific information available to evaluate how Texas' land resources are affected by shale development. This information will be useful to the oil and gas industry and the state, and will inform efforts designed to increase operational efficiency and minimize environmental impacts. It also will provide more complete and credible data that the general public may use to understand the impacts of shale development on ecosystems and the Texas landscape.

Findings

- **Texas hosts an extraordinary degree of biodiversity, due to the diverse topographic, geologic, and climatic conditions across the state.**
- **Texas lands are almost entirely privately-owned. Shale development takes place largely on private lands, which generally are not sites of formal environmental impact studies.**
- **The few studies that have been conducted on erosion and soil contamination from oil and gas development in Texas indicate that well pad development has an increased potential for erosion, and that soil contamination is possible from oil and gas production.**
- **The vast number of new wells drilled in shale formations in Texas since 2007 have had substantial spatial impacts on the landscape. However, horizontal wells have a smaller impact than the equivalent number of vertical wells would have had. When operators use a single well pad for multiple wells, surface impacts are significantly reduced.**
- **Baseline land and habitat conditions at the oil and gas play level should be characterized, and changes to wildlife populations and vegetation should be tracked over time where there are opportunities on both private and public lands.**
- **The most comprehensive information on species-specific impacts has been compiled for the Dunes Sagebrush Lizard and Lesser Prairie Chicken, with extensive studies of changes to their habitats and their life cycles and requirements. Both species are covered by voluntary conservation plans overseen by state agencies.**
- **Landowners in Texas who do not own the mineral rights associated with their property have very limited control over oil and gas operations.**
- **Most states where development of shale resources is occurring have a surface damage act in place to protect the rights of landowners who do not own the mineral rights associated with their property. In Texas, if the surface owner controls any portion of the mineral rights, the owner may be able to use contractual provisions to negotiate with the operator and resolve disputes. In addition, if the owner discovers damages caused by the operator within the statute of limitations time frame—two years—the tort/legal system may provide relief. Damages for the landowner are capped at the value of the damaged property and do not cover the actual cost of remediation.**
- **Data on environmental impacts of oil and gas development reside in several different state and federal agencies, and there is not a single database, readily searchable and available online, that integrates the data across different entities.**

Recommendations

- **Baseline land and habitat conditions at the oil and gas play level should be characterized, and changes to wildlife populations and vegetation should be tracked over time where there are opportunities on both private and public lands.**
- **The effectiveness of voluntary programs to conserve at-risk species should be studied, along with options for incentives to conserve at-risk species and reduce effects on land resources by oil and gas development activities.**
- **Advantages and disadvantages of adopting a surface damages act to address the gaps in legal protection for landowners who do not own the minerals associated with their property should be evaluated.**
- **The existing, nonproprietary information about land impacts of shale development that is collected and evaluated by multiple state and federal agencies should be assembled and made available online to the public.**

5

Air Quality

- The production of shale resources results in emissions of greenhouse gases, photochemical air pollutants, and air toxics.
- Recent federal and state regulations have reduced emissions from multiple types of emission sources.
- Emissions in many categories associated with shale resource production are dominated by a small sub-population of high-emitting sources.
- Development of inexpensive, robust, reliable, and accurate methods of rapidly finding high-emitting sources has the potential to reduce emissions.
- Shale resource development both directly and indirectly impacts air quality. Indirect impacts include reductions in emissions associated with the substitution of natural gas for coal in electricity generation. Comprehensive assessments of both direct and indirect impacts to air quality from the production of shale resources are complex.
- There is limited information concerning exposures to air toxics emissions and their corresponding health impacts. Targeted research in this area should be conducted.

The production of shale resources results in emissions of greenhouse gases, photochemical air pollutants, and air toxics.[8] Emissions of greenhouse gases, photochemical air pollutants, and air toxics also occur as a result of the processing, distribution, and use of shale resources, and as the production of shale resources has increased, there have been changes, including both increases and decreases, in air emissions from these "downstream" sources. These changes due to downstream

[8] Greenhouse gases have heat-absorbing properties that trap outgoing long-wave radiation from the Earth, which results in higher surface air temperatures than would exist without their presence. Primary greenhouse gases are carbon dioxide, halocarbons, methane, nitrous oxide, ozone, and water vapor.

operations can, at times, be larger than the changes in emissions associated with production. Because shale resources are combined with oil and gas from other types of production in downstream operations, it is difficult to ascribe precisely those downstream emissions that can or should be attributed to shale energy development and those that are not. Yet because these downstream changes can be important in presenting a complete picture of the air impacts of shale resources, this chapter takes a broad view of the overall supply chains for shale resources. In some cases, it will be possible to provide specific information about the emissions and impacts associated with shale resources, but in other cases, only aggregate data on oil and gas emissions are available. These aggregate data will be presented and appropriately highlighted as aggregated information.

Air emission sources from shale resource production, and from the oil and gas production, processing, and distribution sector broadly, are diverse, have complex behavior, and are distributed across a large number of individual sites. For example, the Eagle Ford Shale production region in South Central Texas and the Barnett Shale production region in North Central Texas each have on the order of 10,000 production sites. The number and types of emission sources at production sites vary (TCEQ, 2012), and operational practices have evolved in recent years. Air pollutants are also released from natural gas compressor stations and processing plants as well as from the heavy-duty trucks required to transport liquids routinely produced during the operation of many oil and gas production sites. In addition, emission sources can be continuous or intermittent, and in the case of maintenance events, infrequent. Although the emissions are diverse and complex, recent measurements, including many in Texas, have improved the state of knowledge about emissions from the production, processing, and delivery of shale resources.

Although understanding emissions is important, quantifying emissions is just a first step in assessing their implications for human health and climate impacts, which are varied and can occur over very different spatial and temporal scales. Direct human health impacts of air pollutant emissions occur over local and regional scales and exposures generally occur over periods of hours to days. Climate impacts of greenhouse gas emissions are global and occur over time periods of decades. Converting information about emissions into estimates of human health and climate impacts requires the use of models. For pollutants such as air toxics, local emission estimates and dispersion modeling are the primary analysis tools. For regional photochemical air pollutants, local emissions together with inventories of emissions over spatial scales of hundreds of kilometers, coupled with regional photochemical models, are used to assess impacts. For greenhouse gases, national or global models couple emissions data with an assessment of atmospheric residence times and the relative radiative forcings of the various greenhouse gases.

Overall, the information and data available on emissions are more extensive and their interpretation involves fewer assumptions than assessments of human health and climate impacts. Therefore, much of this chapter will focus on summarizing scientific understanding of emissions associated with shale resource production, processing, and delivery in Texas. Whenever possible, these assessments of emissions will be coupled with assessments of human health and climate impacts, but in many cases these impact assessments will have significant uncertainties.

Finally, atmospheric impacts of shale resource development can extend beyond changes in emissions from oil and gas production, processing, and delivery. The availability of low-cost natural gas derived from shale resources influences fuel choices, and changes in fuel choices can impact air quality in a variety of ways. A particularly significant example in Texas and throughout much of the United States is the substitution of natural gas for coal in electricity generation. As natural gas prices have decreased over the past decade relative to coal and as regulatory initiatives were introduced, electricity generation from natural gas in the Texas electricity grid increased by approximately 25 percent (for the period 2010 through 2015), while over the same time period electricity generation from coal and lignite decreased by approximately 15 percent (EIA, 2016). In the Texas grid, the substitution of natural gas for coal in electricity generation results in reductions in the emissions of carbon dioxide (CO_2) and criteria air pollutants including sulfur dioxide and nitrogen oxides, or NOx (Alhajeri, et al., 2011; Pacsi, et al. 2013, 2015). Reductions in downstream emissions are, in the case of CO_2, sulfur dioxide, and $NO_{X,}$ greater than the increases in emissions due to production. The result is that the net effect of shale resources on air quality in Texas depends on changes in production, transportation, and use of the fuels derived from shale. These supply chain impacts of shale resource use will also be described, and to the extent possible, quantified in this chapter (Allen, 2016).

Although characterizing the impact of the production and use of shale resources on air quality is challenging, emissions from oil and gas production basins in Texas have been studied and characterized to a greater extent than production regions in most other states. The sections below describe emissions and impacts associated with shale resource production and impacts integrated over supply chains for oil and gas production regions in Texas. Whenever possible, data for Texas are benchmarked against other oil and gas production regions.

EMISSIONS AND IMPACTS

Greenhouse Gas Emissions

This section summarizes the extensive measurements and analyses that have been performed, largely since 2012, to characterize greenhouse gas emissions from the natural gas supply chain. These measurements have transformed understanding of emissions from the oil and gas sector in the United States, and although focused on greenhouse gases, especially methane, the results have implications for other types of emissions.

When combusted to produce energy, greenhouse gas emissions of natural gas, per unit of energy released, are lower than the other two principal fossil fuels, petroleum and coal. As natural gas has displaced coal in electricity generation in Texas and throughout the United States, the lower CO_2 emissions from natural gas combustion relative to coal combustion have driven total emissions of CO_2 in the United States lower. Recent national emission inventories from the U.S. Environmental Protection Agency (EPA) have reported total greenhouse gas emissions from electricity generation decreased by 15 percent between 2005 and 2014 (EPA, 2017c). Researchers from the National Oceanic and Atmospheric Administration predict that nationally, emissions of CO_2 from electricity generation in 2012 were 23 percent lower than they would have been if coal had continued to provide the same fraction of electric power as in 1997 (De Gouw et al., 2014).

Although the greenhouse gas footprint of natural gas combustion is lower than the footprint associated with coal or petroleum combustion, emissions along the supply chain of natural gas can change this footprint. Methane (CH_4), the primary component of natural gas, is a potent greenhouse gas and can be emitted at multiple points along the supply chain, from the wellhead to the point of combustion. If the methane emissions along the natural gas supply chain are large enough, they can change the greenhouse gas emission footprint of natural gas relative to other fuels. Thus, assessments of the overall greenhouse gas footprint of the production and use of shale resources have been dominated by issues associated with methane emissions. The extent to which methane emissions might change the greenhouse gas footprint of natural gas relative to other fuels depends on the time frame over which the warming effects of methane are evaluated and the corresponding atmospheric warming potency assumed for methane.

Potencies of greenhouse gases are typically expressed as global warming potentials (GWPs), which represent the ratio of radiative forcing of the atmosphere of a specific greenhouse gas relative to the radiative forcing of CO_2. In inventories of emissions developed over the past several years by the EPA, methane is generally assumed to have a GWP of 25 (EPA, 2015), indicating that for each kilogram (kg) of methane emitted, an emission of 25 kg of CO_2 would produce a similar radiative forcing of the atmosphere (1 kg of methane has a CO_2 equivalent of 25 kg). However, methane GWPs of 28 to 36 or 84 to 87, relative to CO_2, can also be assumed (IPCC, 2013). These differences in assumed GWPs are due to the fact that methane is oxidized in the atmosphere to CO_2, over a roughly decadal time scale. Methane GWPs of 28 to 36 relative to CO_2 assume that radiative forcings are integrated over 100 years. For approximately the first decade of this century-long period, the emitted carbon is in methane, but for most of this 100-year period, the emitted carbon has been oxidized to CO_2. In contrast, methane GWPs of 84 to 87 (IPCC, 2013) are based on a 20-year time period. For either a 100-year or 20-year time horizon, the GWP of methane is reported as a range to reflect additional forcing due to climate-carbon feedbacks. At any timescale, methane, the primary constituent of natural gas, is a more potent greenhouse gas than CO_2.

Thus, the reduction in radiative forcing that can be achieved from using natural gas as a substitute for other fossil fuels will depend on the time horizon used in determining the GWP of methane. Some studies have performed analyses comparing natural gas to other fossil fuels, for a variety of uses, examining radiative forcing as a function of time (Alvarez et al., 2012). For example, a 2012 study demonstrated that switching electricity generation from coal to natural gas combined cycle electricity generation (with its high thermal efficiency and lower greenhouse gas emissions in combustion) will always cause a net climate benefit so long as the rate of methane leakage in the entire natural gas supply system is less than about 3 percent of gas produced (Alvarez et al., 2012). The leak percentage (also called emissions intensity) that can be accommodated while still producing a net reduction in radiative forcing increases as the time horizon for the impact increases (and the GWP for methane decreases). Studies that have examined a variety of fuel-switching scenarios in transportation applications have concluded that climate benefits from some fuel substitutions in transportation applications require methane leakage rates of less than 1 percent (Alvarez et al., 2012; Camuzeaux et al., 2015). Thus, using natural gas instead of other fossil fuels produces a climate benefit as long as the methane emissions along the full supply chain, as a percentage of the methane in the natural gas produced, are less than 1 percent (for transportation uses) to less than 3 percent (for electricity generation).

These analyses provide a context for estimates of methane emissions along the natural gas supply chain; however, methane released as a percentage of the methane in the natural gas produced can vary, over a wide range. Observational studies suggest that the methane emissions intensity in natural gas production regions in Texas range from 0.5 percent to 1.5 percent; nationally, emission intensities in production regions vary from less than 0.5 percent to 5 percent or more (Allen, 2016). Some regions within Texas are estimated to be among the highest emitting regions on an absolute basis; this is consistent with the extensive oil and gas production activity in Texas. Figure 5-1 shows the distribution of methane emissions in the United States, based on the EPA's 2012 national inventory of methane emissions from oil and gas operations (Maasakkers et al., 2016).

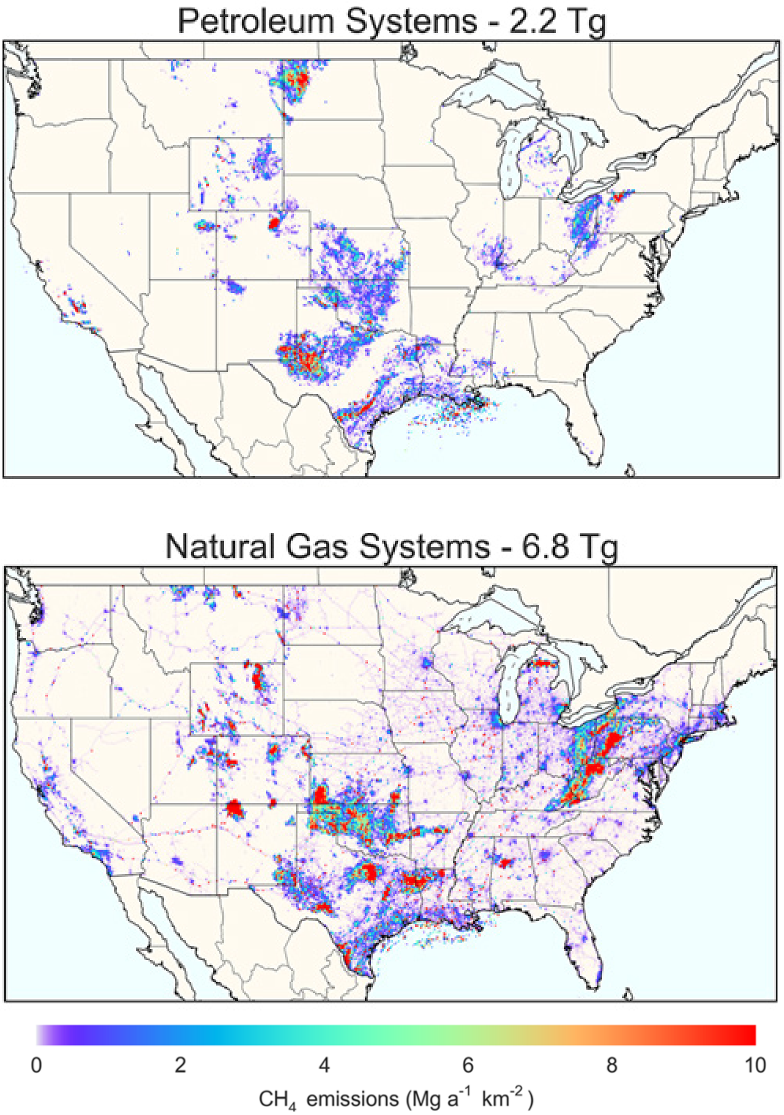

FIGURE 5-1 Spatial distribution of methane emissions from oil and gas operations in the United States, as estimated in the 2012 U.S. Greenhouse Gas Inventory assembled by the EPA (Tg – teragrams).
SOURCE: Maasakkers et al., 2016.

In addition to these types of variations in emissions across space, emissions also vary over time. For example, as wells age, operational practices change and emissions can change, sometimes significantly. Yet another source of complexity owes to the fact that national estimates of methane emissions as a percentage of natural gas production may or may not be adjusted for co-products produced along with natural gas. Many natural gas wells also produce substantial amounts of natural gas liquids and oil. Many oil wells co-produce gas, even though their primary market mission is to produce oil, and regions that produce large amounts of oil relative to natural gas (e.g., the Denver-Julesburg region in Colorado) tend to have higher amounts of methane emitted per volume of natural gas produced, as compared to regions (e.g., the Marcellus in Northeast Pennsylvania) that do not produce oil with natural gas (Zavala-Araiza et al., 2015a). In cases of wells producing multiple products, a variety of methods have been used to equitably allocate methane emissions among natural gas and natural gas liquid and oil products (Zavala-Araiza et al., 2015a), but these redistributions of methane emissions are often not reflected in national or regional emission reporting.

One of the most extensively studied oil and natural gas production regions in the United States is the Barnett Shale in North Central Texas. A summary of studies from the Barnett Shale region reported that methane emissions averaged over the entire production basin range from 1.2 to 1.9 percent of gas production (Zavala-Araiza et al., 2015b). This snapshot of the average percentage of methane emitted along the natural gas supply chain in the Barnett Shale (i.e., gas produced and consumed in the Barnett Shale region) is below the 3 percent threshold for emission intensity needed for a climate benefit when natural gas is substituted for coal as a fuel for electricity generation. However, several mitigating factors must be noted:

- The Barnett Shale production region contains only part of the natural gas supply chain. Emissions associated with long distance transmission and emissions associated with the use of the natural gas in applications such as electricity generation are not included in the emissions total for the Barnett Shale.
- The Barnett Shale is one of only several major shale plays in Texas; each of the separate shale plays may have unique characteristics.
- Most of the emissions studies were done between 2012 and 2014. The EPA promulgated regulations for “new and modified sources” toward the end of that period that may have reduced emissions.
- Some operators participate in voluntary emission reduction programs. Some of these may be internal company programs, and some may be participatory programs such as the EPA Natural Gas Star program and the new program under Gas Star, the EPA Methane Challenge. These voluntary efforts may also reduce emissions from the base levels measured from 2012 to 2014.

The National Energy Technology Laboratory (NETL) (Littlefield, et al., 2017) has concluded that the national average methane emission intensity for natural gas is 1.7 percent. Other reviews of the literature come to different conclusions (ICF, 2016), and overall, the t otal national emissions intensity from the natural gas supply chain remains an active area of scientific investigation. With methane emissions in the range of 1.7 percent of natural gas produced, the production of shale resources results in emissions of greenhouse gases.

Knowledge of emissions, and how emissions might change over time from specific sources, will continue to evolve. An active area of investigation is the variability in emissions from source to source. Multiple studies have indicated that in the Barnett Shale, and in all other oil and gas production regions that have been studied, a small fraction of the sources account for a majority of the emissions.

This phenomenon applies at multiple scales (individual devices, large equipment, and whole sites). Collectively, the largest emitters have been referred to as "super emitters," although this term has no widely-accepted definition. The concept of a "super emitter" or "high emitter" classification in emission inventories is not new to air quality research. It has been known for decades that roughly 10 percent of the passenger car fleet in the United States contributes roughly 50 percent of all on-road emissions (Stedman, 1989; NRC, 2001). The situation for many source types in the petroleum and natural gas supply chains is analogous. For example, approximately 50,000 wells (of the roughly 500,000 natural gas wells in the United States) vent during a process referred to as a liquid unloading, and a small fraction of these venting wells, perhaps 3 to 5 percent, likely account for half of unloading emissions (Allen et al., 2015b). Similarly, multiple studies (Prasino Group, 2013; Allen et al., 2015a; Gibbs, 2015) have found that a small sub-population of pneumatic controllers dominates emissions. Pneumatic controllers are devices that use pressurized natural gas to control the opening and closing of control valves, primarily at facilities that do not have a source of electricity, and are estimated to be the largest source of methane emissions in the petroleum and natural gas supply chains. One study has estimated that 20 percent of pneumatic controllers in a national sampling of natural gas sites account for 95 percent of pneumatic controller emissions (Allen et al., 2015a). Another 2015 evaluation found that 3.5 percent of controllers accounted for 73 percent of controller emissions at sites sampled in Oklahoma (Gibbs, 2015). Across multiple carefully studied oil and gas sources, the top 5 percent of sources account for at least 50 percent of the emissions from the source category (Brandt et al., 2016).

Another way in which high-emitting sources have been defined is facility- or site-based, rather than equipment-based. In defining a high-emitting site, it is important to account for the size of the site, as characterized by the amount of gas produced, processed, or used at the site. A common approach is to normalize emissions by site size or throughput. For example, a 2015 study made measurements downwind of natural gas gathering and processing facilities and normalized methane emissions by total gas throughput at the sites (Mitchell et al., 2015). Across all sites, emissions averaged 0.20 percent of throughput for gathering facilities; however, some facilities had emissions that were in excess of 10 percent of gas throughput, and 30 percent of the facilities accounted for 80 percent of emissions. A study that analyzed data taken downwind of natural gas supply chain sites in the Barnett Shale region defined functional super-emitting sites as those with the highest proportional loss rates—that is, the amount of methane emitted relative to methane produced or methane throughput. Using this definition, 77 percent of the methane emissions were accounted for by 15 percent of the sites with the highest normalized emissions, with more than 50 percent of the emissions coming from only 2 percent of the sites (Zavala-Araiza et al., 2015c).

An issue that is still unresolved is why some sources become high emitters. Analogies with vehicles can, again, provide some insights. Vehicle testing reveals that vehicle type, maintenance, and operation all play a role in determining whether a vehicle becomes a high emitter (NRC, 2001). In a similar way, in the oil and gas sector, there are some sources that are more likely than others to become high emitters, but operational practices also play a role. For example, in the source category of gas well liquid unloadings, mature wells with low reservoir pressure and high rates of liquid production are more likely to have high unloading emissions. Differences in operational practices, in contrast, can lead to differences in emissions from pneumatic controllers and compressors (Allen, 2016; Allen et al., 2015a; Harrison et al., 2011).

Important evidence of the source of high-emitting sources is provided by recent overflights of natural gas production sites. Out of more than 8,200 sites sampled, 4 percent of the sites had individual sources with emissions estimated to be greater than 1 to 3 grams per second (g/s) and detectable by infrared camera. The frequency of such super-emitting sites ranged from less than 1 percent in the Powder River Basin of Wyoming, to 5.4 percent in the Eagle Ford production region of South Central Texas, and 14 percent in the Bakken Shale production region in North Dakota (Lyon et al., 2016). Again, however, the distribution of emissions data provides important insights. In the Barnett Shale, 3.5 percent of sites had emissions detectable by infrared camera; these emissions, however, were unevenly distributed among gas and oil production sites. Only 0.7 percent of sites with high gas-to-oil production ratios had detectable emissions, while 1.4 percent and 20.6 percent of sites with medium and low gas-to-oil production ratios had detectable emissions. In all production regions, in more than 90 percent of the cases of detectable emissions, the points of release of the emissions were the liquid storage tanks on site. Multiple sources of emissions can vent at liquid storage tanks (e.g., storage tank venting, liquid unloadings, emission due to stuck separator dump valves), so the location of the emission does not uniquely identify the source. Nevertheless, these flyover and other observations of high-emitting sites provide qualitative insights into the sources associated with high-emitting sources. How these observations are reconciled with national and regional inventories of emissions is also uncertain. Some high-emitting sites detected during observation studies may be experiencing planned episodic events, accounted for in inventories of emissions. Others may be due to unplanned events. A recent analysis performed for the Barnett Shale concludes that a majority of high-emitting sites are due to some type of malfunction (Zavala-Araiza et al., 2017).

Overall, **emissions in many categories associated with shale resource production are dominated by a small sub-population of high-emitting sources. Development of inexpensive, robust, reliable, and accurate methods of rapidly finding high-emitting sources has the potential to reduce emissions.**

Photochemical Air Pollutants and Air Toxics

Photochemical air pollutants of concern that are directly emitted by oil and gas production activities are Volatile Organic Compounds (VOCs) and NOx. Emissions of VOCs and NOx are regulated primarily on the basis of the extent to which they react in the atmosphere to produce ozone and particulate matter. Elevated concentrations of ozone and fine particulate matter have been shown to contribute to a variety of cardiovascular and respiratory diseases (EPA, 2011). Air toxics of concern include particulate matter from diesel trucks and diesel engines, some hydrocarbon species, including benzene (C_6H_6) as well as a number of other compounds with direct health impacts (EPA, 2017a).

Emissions of photochemical air pollutants and air toxics from shale resource development in Texas generally are similar to the types of emissions from legacy oil and gas development. There are some differences in how shale wells are developed and operated that may produce unique emission types. The primary change in emissions from shale development is due to the increase in activity of oil and gas development, and not to the unique nature of the shale resource. Therefore, the spatial distribution of emissions of criteria air pollutants and air toxics due to oil and gas operations generally follows the spatial distribution of oil and gas production operations. A national mapping of VOC emissions is shown in Figure 5-2 (EPA, 2017b).

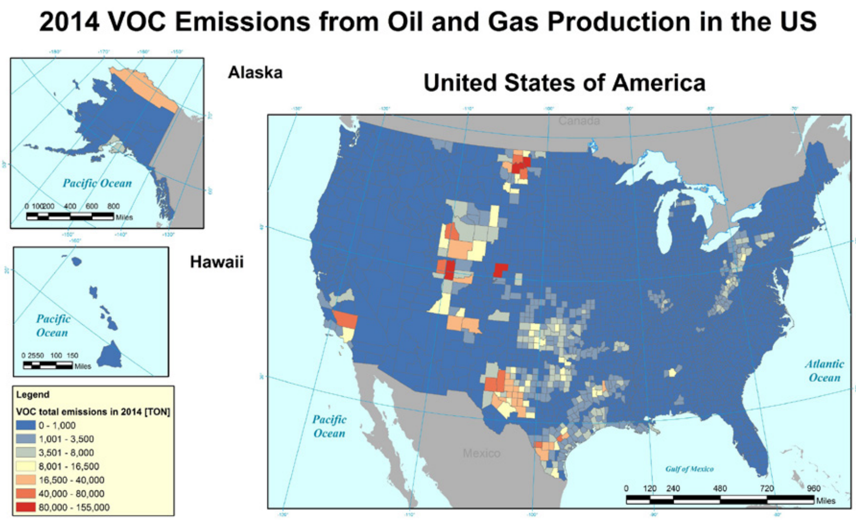

FIGURE 5-2 2014 Volatile Organic Compound (VOC) county-level emissions from U.S. oil and gas operations.
SOURCE: EPA, 2017b.

Although emissions of criteria air pollutants and air toxics from oil and gas production and processing generally follow spatial patterns of production activity, differences in the regulation of emissions can change those spatial patterns. Ozone (O_3) and fine particulate matter (PM) concentrations, which form the basis for many regulations of VOC and NOx emissions, vary regionally. Therefore, although there are some national regulations limiting VOC and NOx emissions from oil and gas operations, the extent of VOC and NOx emission controls also varies by region. An additional factor driving regional differences in the regulation of VOC and NOx emissions from oil and gas emissions is the degree to which VOC and NOx emissions from oil and gas operations will combine and react with other local sources of VOC and NOx emissions. Since both natural and man-made emissions of VOC and NOx vary significantly from location to location, the extent of emission controls applied to VOC and NOx emissions from oil and gas operations varies by region. Even within Texas, local conditions vary. In the Eagle Ford and Haynesville production regions, ozone formation due to oil and gas production activities is primarily due to NOx emissions from oil and gas sources reacting with natural sources of VOCs. In the Barnett Shale, where natural sources of VOC emissions are far less extensive than in the Eagle Ford and Haynesville regions, the concern is oil and gas NOx emissions reacting with oil and gas and urban VOC emissions (Pacsi et al., 2013, 2015). Therefore, even within Texas, there may be different levels of concern about

VOC and NOx emissions from oil and gas operations.

At a regional scale, the magnitude of VOC and NOx emissions associated with oil and gas supply chains makes them significant—and sometimes dominant—sources of these emissions. For example, in Texas, the 2011 EPA National Emissions Inventory reported "petroleum and related industries" (including downstream processing) accounted for 45 percent and 15 percent of total anthropogenic VOC and NOx emissions, respectively. Nationally, those percentages are 17 percent and 4.7 percent. These emissions have been increasing over the past decade in regions with increasing oil and gas development (Allen, 2016; Duncan et al., 2016).

Although it is difficult, for reasons outlined earlier in this chapter, to disaggregate emissions from shale resource production and processing from this total, emissions in specific shale production regions have been estimated. For example, the Texas Commission on Environmental Quality (TCEQ) estimated VOC emissions from the Barnett Shale, in their 2009 special inventory, to be 19,000 tons per year (Zavala-Araiza, et al., 2014). These VOC emissions for the Barnett Shale production region, which alone are approximately 10 percent of the state total for VOC emissions from the oil and gas sector prior to shale resource development, further support the finding that the production and use of shale resources is a major source of VOC emissions in Texas.

Within the oil and gas sector, major sources of VOC and NOx emissions, along with greenhouse gas emissions, are listed in Table 5-1. The major sources for each type of pollutant are different. NOx emissions arise from combustion. Combustion engines are used in several life cycle phases of oil and gas production. For example, during the well drilling and completion phase, drilling platform engines and fracturing pump engines are used, and transport truck engines are used. Recent shale gas well completions are unique in that they use extensive hydraulic fracturing, which requires operation of fracturing pump engines and often involves more truck transport of the fracturing material, such as water and sand, than traditional wells. During the normal operation phase of the completed well, pipeline compressor engines and oil truck transportation engines are used, as they are in traditional oil and gas wells.

A large source of VOC emissions is the vaporization of stored hydrocarbon products in surface storage tanks at sites that produce oil. In addition, certain gas and oil treatment processes can cause VOC emissions, along with leaks and maintenance events. Finally, many well sites do not have access to electrical power, and so use natural gas pressure as the motive force for devices like pneumatic controllers and pumps, which discharge the used power gas to the atmosphere.

TABLE 5-1 Major oil and gas sources of emissions for greenhouse gases, VOCs, and NOx.

Major Sources of Emissions from Oil and Natural Gas Supply Chains *(Note: source strengths can vary over time and from region to region and not all sources are active in all phases of a well's life*)		
Greenhouse Gases	VOCs	NOx
Well completions* Pneumatic controllers, pumps Gas dehydration and treatment Flaring Compressors Equipment leaks Liquid unloadings Tank vents Maintenance and upset events Natural gas engine exhaust (methane slip) Natural gas pipeline leaks	Well completions* Tanks, loading operations Equipment leaks Pneumatic controllers Pneumatic pumps Engine exhaust (diesel engines)*	Drilling and fracturing (diesel engine exhaust)* Compression (natural gas engine exhaust) Process heaters Heavy-duty diesel trucks

Note: * indicates sources that might be larger under modern shale development and production practices.
SOURCE: Adapted from Allen, 2016.

Although just examining anthropogenic emissions gives one picture of the role of oil and gas operations in photochemical air pollution in Texas, examining all pollutant sources and the types of pollutants emitted alters that picture somewhat. Total emissions of NOx in the state are dominated by emissions from man-made sources and NOx emissions from petroleum and related industries account for 15 percent of the anthropogenic NOx emissions in Texas. In contrast, however, the largest contributors to VOC emissions in the state are natural sources. One evaluation, for example, estimated that biogenic emissions in Texas are larger than anthropogenic emissions, although they are distributed in different regions than the anthropogenic VOC sources (Wiedinmyer et al., 2001). Vegetation, especially certain species of trees, dominates biogenic VOC emissions. The level of biogenic emissions depends strongly on weather conditions, but in general, the fraction of total VOC emissions in Texas accounted for by petroleum and related industries in most years is close to 20 percent, even though these sources are the largest single anthropogenic source (45 percent of anthropogenic emissions, including downstream sources). In addition, not all VOC emissions contribute equally to ozone and particulate matter formation. The VOC emissions from oil and gas operations are dominated by compounds (alkanes) that are far less reactive in the atmosphere and contribute less to ozone and particulate matter formation than emissions from natural sources (isoprene and terpenes).

The overall contribution of oil and gas sources to VOC reactivity in the atmosphere varies substantially from region to region. In the Eagle Ford and Haynesville production regions, which have large emissions from natural sources, emissions from oil and gas operations contribute very little to overall VOC reactivity in the atmosphere. In contrast, in regions such as the Barnett and Permian Basin regions, natural VOC emissions are low and therefore oil and gas emission sources can contribute a large fraction of atmospheric VOC reactivity. These differences in VOC reactivity lead to differences in ozone formation, as described in the next section.

Overall, emissions of VOCs and NOx from oil and gas operations can contribute to photochemical air pollution, especially ozone, but the impacts will vary by region. Multiple contrasting case studies illustrate the range of impacts that can occur. In the Eagle Ford Shale in South Texas, and in the Haynesville Shale in East Texas, emissions of NOx react with relatively large emissions of biogenic hydrocarbons in the region to produce ozone that impacts downwind metropolitan regions (Kemball-Cook et al., 2010; Pacsi et al., 2015). The magnitude of the increased ozone mixing ratios in downwind metropolitan regions can be up to several parts per billion (ppb). Impacts will vary from day to day, depending on whether wind speed and direction will transport air from the production region to urban areas. These ozone enhancements in downwind urban areas are on some days comparable to the impacts from individual local sources and can impact whether downwind regions attain National Ambient Air Quality Standards. In contrast to the situation in the Eagle Ford and Haynesville Shales, Barnett Shale emissions occur in a region in which background reactivity of the atmosphere is relatively low. Direct emissions from oil and gas operations in this region, which has a relatively high natural gas-to-oil production ratio, produce relatively low quantities of ozone (Pacsi et al., 2013).

In contrast to the photochemical air pollutants, data are relatively sparse on toxic air pollutants. Measurements of toxic air pollution concentrations in production regions and near wells have been limited. In Texas, in a number of regions influenced by oil and gas production, measurements have been made of benzene, an air toxic that would be expected to be emitted in small quantities with other VOCs in upstream operations.

Measurements funded by the TCEQ have been conducted in the Barnett Shale and Eagle Ford Shale production regions (Bunch et al., 2014; Ethridge et al., 2015; Hildenbrand et al., 2016; Schade and Roest, 2016; TCEQ, 2015b). In general, benzene concentrations measured at central monitoring sites in production regions have been lower than those observed in regions near petroleum refineries.

For example, benzene concentration measurements made at a central monitoring site in the Barnett Shale production region were lower than those observed at a site in Houston near roadways and refineries. The measurements made at the Barnett Shale site were approximately equal to those observed at a downtown Dallas site, located near roadways (TCEQ, 2015a and 2015b; Allen, 2016).

A limited number of studies have examined additional air toxic species in production regions (Olaguer, 2012; Rich et al., 2014). Formaldehyde may be associated with engine emissions (Olaguer, 2012); however, chlorinated organics (Rich et al., 2014) are not typical components of oil and natural gas or their combustion products, and their origin is unclear. Hypotheses include fracturing fluid constituents or the reaction products that may occur as fracturing fluids interact with reservoir fluids and surfaces at the elevated temperatures and pressures experienced downhole (Allen, 2014; 2016), then vent during processes such as well completion flowbacks.

The data available for shale resource production regions are limited, however, in that they have generally been made at sites that are within production regions, but not directly adjacent to individual well sites. Air toxic concentrations in production regions would be expected to vary, depending on the amount and composition of the oil produced at individual sites and the activities underway at the sites. Overall, there is a general lack of information on the spatial distributions of air toxic concentrations in oil and gas production regions.

Understanding of the public health impacts of air pollutant emissions from shale gas production is also limited (Adgate et al., 2014). A recent review of the literature on the health impacts of unconventional natural gas development (Werner et al., 2015) found only seven out of more than 1,000 studies that reported on health impacts, were based on "primary and/or secondary data" and "contained evidence of direct causality or strong associations between environmental health hazards related to UNGD (unconventional natural gas development) and health outcomes (direct symptoms, disease, illness)." Among the limited number of studies identified as "highly relevant" (Werner et al., 2015) was a study performed by the Texas Department of State Health Services (TDSHS) in Dish, Texas in the Barnett Shale production region. Additional work has been performed by the TDSHS in Flower Mound, Texas, also in the Barnett Shale production region.

The Dish study used a biomonitoring approach, analyzing blood and urine samples for volatile organic compounds. The study concluded that the results were "not consistent with community-wide exposures to airborne pollutants, such as those that might be associated with natural gas drilling operations" (TDSHS, 2010). The study also reported that other exposures might confound their findings, such as smoking or the use of consumer products containing these compounds.

The Flower Mound study investigated cancer incidence and concluded "the number of childhood leukemia subtypes, childhood brain/CNS cancer subtypes, all-age leukemia sub-types, and all age non-Hodgkin's lymphoma for Flower Mound ZIP codes 75022 and 75028 were within expected ranges for both males and females. The number of female breast cancer cases found reported for each of these

ZIP codes was statistically "greater than what was expected" (TSDHS, 2011). As pointed out by the TDSHS (2011), however, expected cancer rates in the study were based on population data from 2000 and a large—41%—increase in population over the study period may have led to an underestimate of the expected number of cases (TSDHS, 2011). A strategic research agenda developed for the Appalachian region identifies specific research questions that are applicable to other shale producing regions, including Texas (Health Effects Institute, 2015).

Overall, **there is limited information concerning exposures to air toxics emissions and their corresponding health impacts. Targeted research in this area should be conducted.**

SUPPLY CHAIN AND INDIRECT IMPACTS

Changes in energy supplies have changed how energy is used. One of the largest changes has been the replacement of coal-fired electricity generation with natural gas-fired electricity generation. These changes have been significant in Texas. Changing the fuels used for electricity generation has complex impacts on emissions and air quality, as will be illustrated with two case studies from Texas.

In the Texas electrical grid, operated by the Electric Reliability Council of Texas (ERCOT), natural gas-fired units generally have lower air emissions per kilowatt hour of generation relative to the coal plants, so when lower natural gas prices or other factors drive shifts from coal-based generation to natural gas-based generation, emissions of NOx, PM, sulfur oxides (SOx), and CO_2 decrease (Alhajeri et al., 2011). As natural gas production increases and prices fall, emissions increase locally in the natural gas production areas. Emissions decrease from the coal-fired power plants that are not utilized as extensively, but increase at natural gas-fired power plants that are used more extensively. Overall emissions throughout the ERCOT region decrease, but because the emission decreases and increases occur in different locations, the overall impact on air quality is complex. Figures 5-3 and 5-4 illustrate patterns of changes in ozone concentrations and electricity generation (Pacsi et al., 2015).

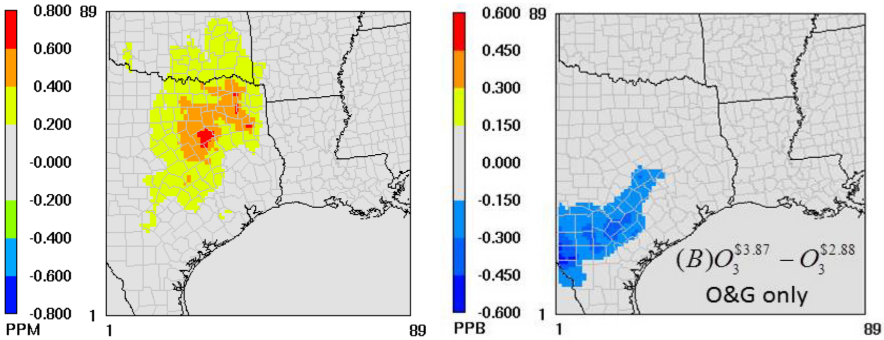

FIGURE 5-3 The left panel shows decreases in summer month average daily maximum eight-hour ozone concentration due to shifting of electricity generation from coal- to natural gas-fired units. This is based on a natural gas price change from $7.74 per thousand standard cubic feet (scf) to $2.88 per thousand scf. The shift from coal to natural gas fired generation lowers NOx emissions, lowering ozone concentration. The right panel shows increases in summer month average daily maximum eight-hour ozone concentration due to increases in Eagle Ford production sufficient to supply the natural gas for the increased natural gas consumption in electricity generation. SOURCE: Pacsi et al., 2015.

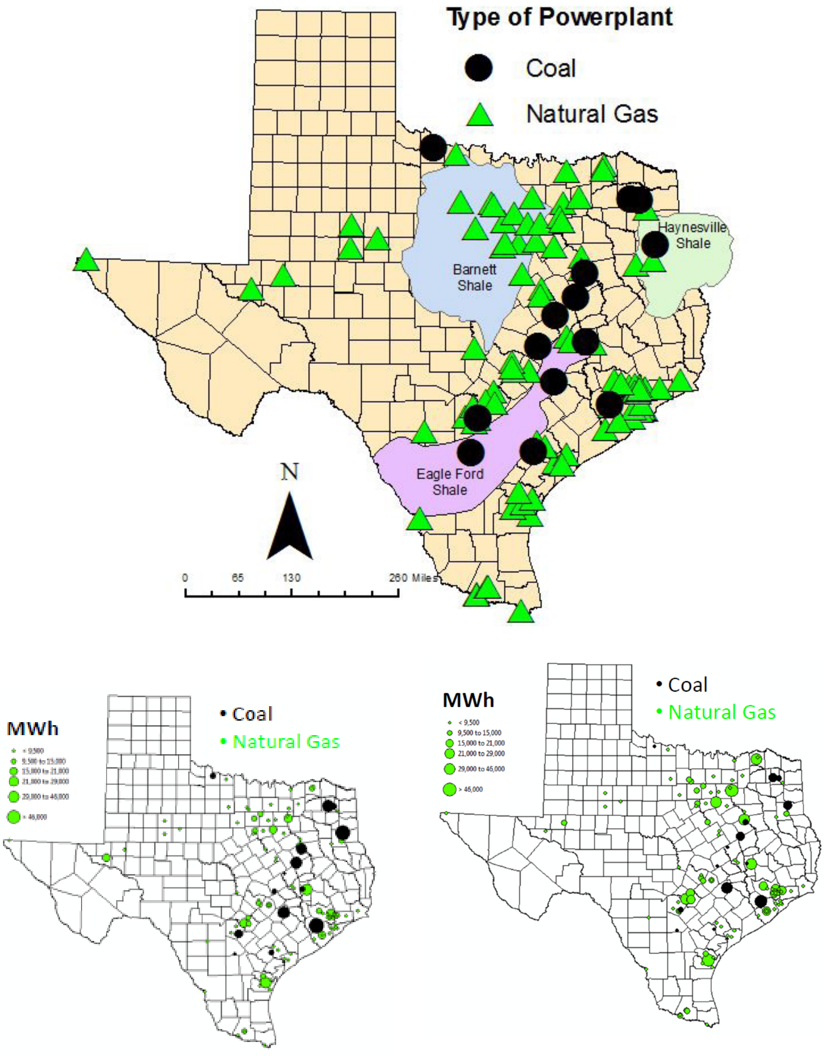

FIGURE 5-4 Locations of coal-fired and natural gas-fired power generation relative to oil and gas production regions in Texas (top panel). Distribution of electricity generation at high natural gas prices (sizes of dots representing power plants is proportional to extent of generation; bottom left panel). Distribution of electricity generation at low natural gas prices (sizes of dots proportional to extent of generation; bottom right panel).
SOURCE: Pacsi et al., 2013 and 2015.

As coal-fired power generation decreases, emission reductions are predicted to occur primarily at large coal-fired power plants in Northeast Texas. Reduced NOx emissions from these sources lead to reductions in ozone concentrations in Northeast Texas and downwind regions, because high emissions of biogenic hydrocarbons in the region create conditions that are conducive to ozone formation (Pacsi et al., 2013, 2015). Similarly, NOx emissions from oil and natural gas production in the Eagle Ford lead to increased ozone concentrations in South Texas, as this region also has high emissions of biogenic hydrocarbons and few non-oil and gas emissions of NOx. These increases and decreases in ozone mixing ratios are on the order of several parts per billion on some days. Impacts will vary from day to day, depending on whether wind speed and direction will transport air from the production region to urban areas (monthly average changes are shown in Figure 5-3). These ozone enhancements in downwind urban areas are on some days comparable to the impacts from individual local sources and can impact whether downwind regions attain National Ambient Air Quality Standards.

Not all NOx emissions lead to ozone increases, however. Emissions from oil and gas production in the Barnett Shale lead to small changes in ozone formation. Emissions of biogenic hydrocarbons in the region are low; other reactive hydrocarbons from the Dallas-Fort Worth metropolitan area, located near to or within the Barnett Shale, have generally already reacted before they encounter the NOx emissions from the oil and gas production activities, and the reactivity of the VOC emissions emitted by oil and gas production activities generally is low.

These contrasting case studies of the Barnett and Eagle Ford Shales suggest that the full supply chain air quality impacts of natural gas production and electricity generation will be location dependent. In Texas, replacing coal-fired electricity generation with natural gas-fired electricity generation leads to relatively large air quality improvements in some areas because the reduced emissions of nitrogen oxides from the displaced coal-fired electricity generation occur in regions that have highly reactive hydrocarbons in the atmosphere. Ozone concentrations increase in some oil and gas production regions, but not others, because the reactivity of the hydrocarbons varies from region to region. These model-based predictions of varied ozone impacts are generally consistent with observations of ambient ozone concentrations reported by the Texas Commission on Environmental Quality (TCEQ). For example, the TCEQ reports steadily decreasing ozone concentrations in the Dallas-Fort Worth metropolitan area since 2008, while over the same time period ozone concentrations in San Antonio have been nearly constant to slightly increasing (TCEQ, 2017), which is consistent with the spatial mappings shown in Figure 5-3.

Other complex changes in air quality due to changes in the use of shale resources are possible. For example, the low price of natural gas-related products have changed the raw materials used in chemical manufacturing from petroleum products (naphthas) to ethane and propane (Allen; 2016; DeRosa and Allen, 2015).

This also can influence the magnitude and spatial and temporal patterns of emissions.

- Overall, it can be concluded that shale resource development both directly and indirectly impacts air quality. Indirect impacts include reductions in emissions associated with the substitution of natural gas for coal in electricity generation. Comprehensive assessments of both direct and indirect impacts to air quality from the production of shale resources are complex.

IMPACTS OF AIR POLLUTANT REGULATIONS

Air pollutant regulations are issued either by the federal government or state and local governments. Emissions may be controlled as a result of permitting requirements for new sources or as a result of rules that apply to all existing sources. Companies may also implement controls in order to avoid triggering rule requirements, such as adding controls and/or reducing emissions to avoid triggering Title V or PSD (Prevention of Significant Deterioration) major source permitting requirements.

The federal government issues, under authority of the Clean Air Act in Section 111(b), performance standards for "new and modified sources" under regulations called New Source Performance Standards (NSPS). NSPS regulations are issued for various industries, and in 2012 the EPA issued a set for upstream oil and gas production, called NSPS Subpart OOOO[9] and a subsequent revision in 2016 called NSPS Subpart OOOOa. NSPS Subpart OOOO affects oil and gas facilities constructed, modified, or reconstructed after August 23, 2011, and on or before September 18, 2015. NSPS Subpart OOOOa affects facilities constructed, modified, or reconstructed after September 18, 2015. NSPS Subpart OOOOa includes CH_4 and VOC emission rules and regulations. The rules are aimed at controlling greenhouse gases (primarily methane),

VOC, and sulfur dioxide (SO_2). In general, the regulations require the application of emission controls to specific sources or practices: gas or oil well completions, compressor seal maintenance, selection of pneumatic controller types, controls on pneumatic pumps, and storage tank emissions (where the controlled tank would have emitted greater than six tons per year of VOC), and require a leak detection and repair program (LDAR) for equipment leaks. Emissions can be expected to decrease in the future since each year new sources are added and old sources are retired, changing the net population to the newer standards.

Once new source standards are issued, the EPA is also obligated to consider control standards for existing sources under the Clean Air Act, section 111(d). These can be called Existing Source Performance Standards (ESPS). Existing well sources in Texas far outnumber newly created wells; for example, in 2015 Texas generated

[9] Also known as "Quad O."

16,746 newly drilled oil or gas well completions (RRC, 2016), while the state as a whole had nearly 250,000 existing oil and gas wells (EIA, 2016). Therefore, existing source controls are important. In 2016, under the Obama administration, the EPA began collecting information from oil and gas operators to inform potential future 111(d) ESPS standards for oil and gas production sources. In March 2017, under the (then) new Trump administration, the EPA officially withdrew the information collection request.

These **recent federal and state regulations have reduced emissions from multiple types of emission sources**. For example, emissions of methane from natural gas well completions were reduced by 99 percent from uncontrolled emissions through the implementation of reduced emission completions required by NSPS Subpart OOOO (Allen et al., 2013). Emissions from tank sources with potential emissions over six tons per year of VOC, located at new or modified production sites, are required to be reduced by 95 percent. Prior to the NSPS, well completions and emissions from storage tanks with high oil throughput were estimated to be some of the largest source categories in the oil and gas supply chains.

Some geographic areas in Texas are subject to additional requirements. Texas has several "nonattainment areas," which are areas designated as not attaining the National Ambient Air Quality Standards (NAAQS) as defined in the Clean Air Act Amendments of 1970 (P.L. 91-604, Sec. 109). Nonattainment areas must implement a plan to meet the standard. An area may be a nonattainment area for one pollutant and an attainment area for others.

The major nonattainment areas in Texas have to do with ozone, and include and surround most of the major metropolitan areas in Texas. In 2016, the EPA issued "Control Techniques Guidelines for the Oil and Natural Gas Industry," also called the CTG (EPA, 2016). The CTG aims to reduce emissions from permitted sources in nonattainment areas. The CTG provides recommendations to inform state, local, and tribal air agencies as to what constitutes reasonably available control technologies (RACT) for select oil and natural gas industry emission sources. Air agencies can use the recommendations in the CTG to inform their own determination as to what constitutes RACT for oil and gas emission sources, which are discussed in detail in the EPA CTG document. Application of these guidelines may lead to reductions in emissions from existing oil and gas production in Texas, where that production occurs in nonattainment areas (e.g., areas not in compliance with relevant air quality standards).

In Texas, the state air regulatory agency is the Texas Commission on Environmental Quality (TCEQ). The TCEQ issues permits for new and modified sources as the delegated authority for the EPA and enforces state-specific regulations. In Texas, air permits are issued for new sources in oil and gas operations under a Permit by Rule (PBR), a Standard Permit, or a case-by-case New Source Review (NSR) Air Permit. A Permit by Rule is the state air authorization for activities that produce more than a *de minimis* level of emissions but too little for other more significant permitting options. PBRs can be used only for smaller sources that emit less than a maximum amount of certain pollutants, such as less than 250 tons per year (tpy) of NO_X and less than 25 tons per year of VOCs and SO_2 (Texas Administrative Code (TAC): Title 30, PART 1, §106.4). PBRs are simpler and require less emission control evaluations than standard permits, so some operators add controls to their designs to assure that a site can be issued a PBR.

However, many oil and gas sites in Texas cannot meet the requirements of the oil and gas PBR (§106.352) due to the site size and/or high production rates, in which case they may apply for an air Standard Permit, which has higher emission rate limits than PBRs, but also have dispersion modeling impact requirements as well as control requirements that mimic best available control technology (BACT). The air Standard Permit is regulated in Texas under 30 TAC 116.620 for oil and gas facilities outside of the Barnett Shale area. However, for Barnett Shale oil and gas areas, the state has developed a Non-Rule Standard Permit (NRSP) that is required in the Texas counties of Cooke, Dallas, Denton, Ellis, Erath, Hill, Hood, Jack, Johnson, Montague, Palo Pinto, Parker, Somervell, Tarrant, and Wise, which are located in or near the Dallas-Fort Worth metropolitan area. Oil and gas sites outside of the Barnett Shale region may authorize their sites under the §116.620 Standard Permit or voluntarily under the NRSP.

Each of the Texas air permitting mechanisms also impose requirements for sour gas sites (i.e., sites with greater than 24 parts per million by volume (ppmv) hydrogen sulfide (H_2S) in the gas according to 30 TAC 101.1(96)). The Permit by Rule has minimum setback distance limitations for sour gas sites and also requires registration with the state, while the Standard Permits require an H_2S dispersion modeling impacts demonstration.

The costs of emission reduction strategies have been the topic of multiple studies. For methane emissions, recent studies (ICF International, 2014, 2016) have indicated that some emission reduction technologies have a net positive economic impact since methane that is captured can be added to produced natural gas and sold.

SUMMARY

Emissions from oil and gas operations in Texas roughly scale with oil and gas production rates. As production of oil and gas from shale resources has increased, the importance of emissions associated with these sources also has increased. The impacts of these emissions on human health and welfare are complex and varied, and occur over spatial and temporal scales that range from local impacts over periods of hours, to national and international impacts over periods extending to decades. In addition, there commonly are region-to-region differences in the magnitude and impacts of air emissions, and such regional differences are observed in Texas. A number of recent studies in Texas have improved understanding of the magnitudes and types of emissions associated with oil and gas production from shale resources.

Findings

- **The production of shale resources results in emissions of greenhouse gases, photochemical air pollutants, and air toxics.**
- **Recent federal and state regulations have reduced emissions from multiple types of emission sources.**
- **Emissions in many categories associated with shale resource production are dominated by a small sub-population of high-emitting sources.**
- **Development of inexpensive, robust, reliable, and accurate methods of rapidly finding high-emitting sources has the potential to reduce emissions.**
- **Shale resource development both directly and indirectly impacts air quality. Indirect impacts include reductions in emissions associated with the substitution of natural gas for coal in electricity generation. Comprehensive assessments of both direct and indirect impacts to air quality from the production of shale resources are complex.**

Recommendation

- **There is limited information concerning exposures to air toxics emissions and their corresponding health impacts. Targeted research in this area should be conducted.**

6

Water Quantity and Quality

- Water used in hydraulic fracturing processes in Texas represents a small fraction—less than 1 percent—of total water use statewide. In some regions and locales in Texas, however, water used in hydraulic fracturing represents a significantly larger proportion of local water sources.
- Use of brackish groundwater and produced water for hydraulic fracturing can reduce freshwater use. Increased use of these waters, however, can potentially increase impacts to land and water due to spills and leaks.
- The depth separation between oil-bearing zones and drinking water-bearing zones in Texas makes direct fracturing into drinking water zones unlikely, and it has not been observed in Texas.
- Surface spills and well casing leaks near the surface are the most likely pathways for oil and gas activities to lead to contamination of drinking water sources and environmental damage.
- In Texas, both economics and risk considerations dictate that much of the produced water will continue to be injected in deep wells or used as fracturing fluid to minimize impacts on other water sources.

Some of the significant concerns related to shale oil and gas development and hydraulic fracturing are associated with effects on water resources. This topic has been a subject of intensive debate and study. The U.S. Environmental Protection Agency (EPA), for example, has been studying the potential effects of hydraulic fracturing activities on water systems since 2010. The EPA study of the potential impacts of hydraulic fracturing on drinking water resources was completed in 2016 (EPA, 2016b) and no systematic follow-up efforts are in progress.

Oil and gas development can affect water availability and water quality as well as cause broader environmental concerns. Impacts on water resources can generally be separated into the following categories:

- impacts on water availability and supply;
- subsurface contamination due to migration of fracturing or formation fluid;
- spills or leaks of fracturing, drilling, or formation fluids at or near ground surface; and
- wastewater treatment and/or disposal.

This chapter summarizes what is known about the environmental implications of each of these issues in the state of Texas and identifies key uncertainties in the current assessment of the effects of shale oil and gas development and hydraulic fracturing on water supplies. Where appropriate, recommendations that would reduce the impact of these effects on water availability or quality in Texas are presented. This chapter discusses water-related concerns not addressed elsewhere in this report (e.g., effects of wastewater disposal on induced seismicity are primarily addressed in Chapter 3).

Impacts on surface and groundwater can occur at any stage of the water cycle related to hydraulic fracturing activities. The EPA divides the water cycle into 1) water acquisition for fracturing; 2) chemical mixing of the fracturing fluid; 3) injection of the fracturing fluid; 4) handling of the produced water; and 5) wastewater disposal and/or beneficial use (see Figure 6-1).

Water acquisition involves impacts to water availability and supply. Chemical mixing of the fracturing fluid involves impacts due to spills or leaks. The injection and fracturing process itself may lead to subsurface impacts or impacts to near-surface groundwater through casing leaks. Handling of the produced water at the surface can lead to impacts on surface and groundwater due to spills or leaks or other poor management. Disposal and/or use of the produced waters (i.e., wastewater) may lead to further impacts due to spills or leaks or may be used to limit the need for new water acquisition. This chapter will examine each of these potential impacts relative to Texas.

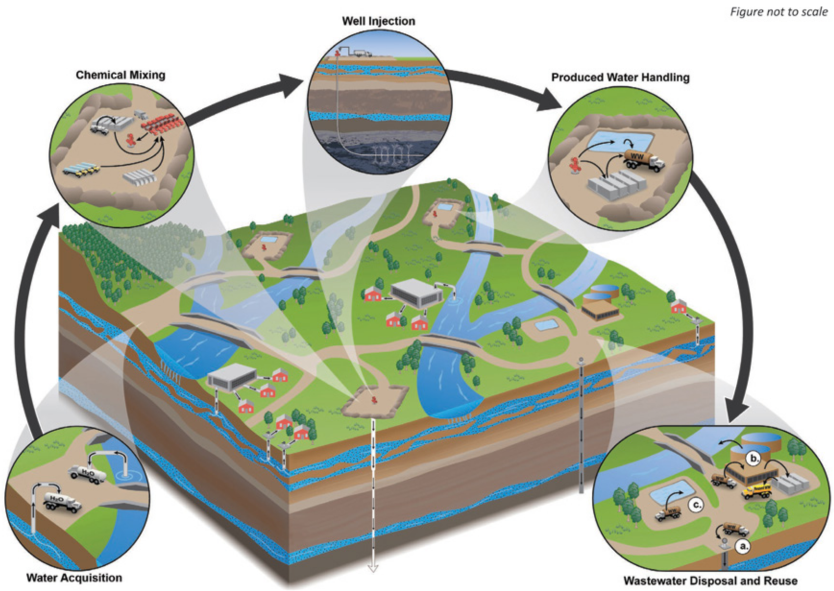

FIGURE 6-1 The water cycle related to hydraulic fracturing activities.
SOURCE: EPA, 2016.

IMPACTS ON WATER AVAILABILITY AND SUPPLY

As noted in Chapter 1, oil and gas production in the United States and in Texas has increased dramatically since the mid-2000s as a result of hydraulic fracturing of shale and tight subsurface formations, coupled with the use of horizontal drilling. It has been estimated that 25,000 to 30,000 wells are hydraulically fractured nationally each year to increase production (EPA, 2016). Texas produces more crude oil than any other U.S. state (EIA, 2017a), and this increased production entails greater use of local water supplies for drilling and fracturing activities.

The average annual water use for hydraulic fracturing activities in 2011 and 2012 in Texas was about 20 billion gallons of water (EPA, 2016). Because this volume represents only 0.2 percent of total water use in the state, and 0.7 percent of total state consumptive use, it might be considered small.[10] However, oil and gas production in Texas often is located in some of the state's most arid and rural areas,

[10] Consumptive water use refers to water that is evaporated, consumed, or transpired by plants, or otherwise unable to be returned to the source.

and the fraction of water used for hydraulic fracturing can be considerably higher in those regions. As much as 90 percent of the total water use in lightly populated rural counties in Texas might be associated with hydraulic fracturing and, in some areas, water use for hydraulic fracturing alone could exceed sustainable groundwater use rates (Nicot and Scanlon, 2012). To cite a specific example, groundwater level declines up to 100 to 200 feet have been recorded in parts of the Permian Basin and Eagle Ford plays (Scanlon et al., 2014a).

Water used in hydraulic fracturing processes in Texas represents a small fraction—less than 1 percent—of total water use statewide. In some regions and locales in Texas, however, water used in hydraulic fracturing represents a significantly larger proportion of local water sources.

In addition, substantial growth in hydraulic fracturing occurred during the same period as the state's most severe single year of drought, 2011. This had the effect of focusing attention on this new and growing water use sector.

Water volumes required for hydraulic fracturing vary greatly by location and by well. Many factors affect the water volume used for hydraulic fracturing, including the type of well (vertical versus horizontal), horizontal extent, and type of fracturing fluid (slickwater, gels, or hybrids). As the horizontal extent of these wells has increased in recent years, so has the water use per well, although water use is increasing at a faster rate. Table 6-1 summarizes the water requirements per well in Texas oil fields (EPA, 2016). They range from a median of less than 1 million gallons per well in the Permian Basin (due to use of a large number of vertical wells) to more than 4 million gallons per well in the Eagle Ford play. The Groundwater Protection Council and the Interstate Oil and Gas Compact Commission sponsor an extensive and publicly-accessible database—FracFocus—with information on, among other things, volumes of water and fracturing chemical volumes (GWPC and IOGCC, 2014).

TABLE 6-1 Water use per well for 2011 and 2012 (partial year).

State	Basin/total[a]	Number of disclosures	Mean (gal)	Median (gal)	10th percentile (gal)	90th percentile (gal)	Literature estimates
Texas	Permian	8,419	1,068,511	841,134	40,090	1,814,633	Many formations reported[b]
	Western Gulf	4,549	3,915,540	3,777,648	173,832	6,786,052	4.5–4.7 million gal (median, Eagle Ford play)[b]
	Fort Worth	2,564	3,880,724	3,881,220	923,381	6,649,406	4.5 million gal (median, Barnett play)[b]
	TX-LA-MS Salt	626	4,261,363	3,139,980	193,768	10,010,707	6–7.5 million gal (median, Texas-Haynesville play) and 0.5-1 million gallons (median, Cotton Valley play)[b]
	Anadarko	604	4,128,702	3,341,310	492,421	8,292,996	Many formations reported[b]
	Other	120	1,601,897	184,239	21,470	5,678,588	NA
	Total	16,882	2,494,452	1,420,613	58,709	6,115,195	Not reported by state[b]

SOURCE: Modified from EPA, 2016.

In Texas, most of the potable water supply comes from groundwater, particularly in the arid to semiarid Eagle Ford play and Permian Basin, where surface water supplies are limited. In Central (e.g., Barnett) and Eastern Texas (e.g., Haynesville), surface water supplies are more frequently used for hydraulic fracturing activities. Although freshwater use for hydraulic fracturing is small on a statewide basis, as noted previously, it can pose a significant demand for local water resources overall in rural areas. Groundwater resources in arid areas of the state may limit water availability to small communities and for agricultural uses. Conservation in agricultural waters and a functioning water market has been proposed as a source of water for hydraulic fracturing and a potential income to agricultural communities. One study showed that by implementing best management practices for conservation of irrigation waters, 420 to 800 million m^3 (111 to 211 billion gallons) of water per year could be diverted from the Lower Rio Grande River Valley to oil and gas activities (Cook and Webber, 2016). There are substantial logistical issues, however, of making use of this water since transportation would be costly and can lead to another set of environmental impacts.

Using alternative (non-potable) waters can decrease the demand placed upon high quality waters. Non-potable brackish surface or ground waters are a substantial resource in West Texas. Another source of brackish water is the water produced in association with oil production, and, to a lesser extent, shale gas production. Here, produced waters are defined as any water that is produced from a well, including flowback (the return of water injected into a well) and formation waters (waters originally in the subsurface formation and being brought to the surface for the first time). Use of produced water in hydraulic fracturing operations can reduce the volumes that would otherwise require disposal. Moreover, reducing deep well disposal could reduce the potential occurrence of induced or triggered seismic events (discussed in Chapter 3). Use of brackish water resources also does not generally lead to competition with drinking water or agricultural sources, particularly if containing high concentrations of salts or total dissolved solids (TDS) (e.g., >10 percent of the salinity of sea water, i.e. >3,000 to 3,500 mg/l TDS). Relatively low salinity brackish waters (<3,000 to 3,500 mg/l TDS) cannot be cost-effectively treated at this time to <1,000 mg/l TDS. These waters, however, could potentially be sources of water for other uses in the future with improvements in water treatment technologies or the value of that water.

Oil and gas operators have leveraged emerging technologies and improved understanding of fluid and formation properties to develop fracturing fluids using poorer quality saline or brackish waters. Unfortunately, much of the current information on alternative waters is dated and may not represent current use patterns. As of 2011, use of produced waters accounted for less than 20 percent of the total water usage for hydraulic fracturing in Texas, although brackish or non-potable groundwater sources accounted for 20 to 30 percent of the total water usage in the Eagle Ford, Eastern Permian Basin, and Anadarko Basin (Nicot and Scanlon, 2012).

Very little brackish water has been used in East Texas or in the Barnett Shale plays (≤3 percent), both of which have had primarily natural gas production. Brackish water (80 percent of total) has been heavily used for shale oil development in the Western Permian Basin (e.g., Delaware Basin) due to the lack of other water sources.

There remain, however, significant barriers to increasing the amount of alternative waters employed in hydraulic fracturing. The use of produced and other non-potable water resources increases the risk of contamination related to water storage, management, and transport at the surface. There is also continuing concern about the detrimental effects of using poor quality waters for fracturing, including poor gelling or viscosity control and potential scaling problems in wells or process equipment. These problems are a strong function of the desired composition of the fracturing fluid. For example, one type of fracturing fluid requires crosslinking of polymers to control viscosity. This type of fluid, referred to as gelled fluid, can be quite sensitive to dissolved salts found in the water used. Fewer problems exist for "slick water fracturing" in which low viscosity fluid is employed and cross-linking of polymers is not required.

The Apache Corporation, a petroleum and natural gas exploration company headquartered in Houston, has demonstrated the ability to use produced waters that have high concentrations of total dissolved solids (TDS >100,000 mg/l) directly for hydraulic fracturing with minimal treatment at a facility located near Barnhart (Seeley, 2014). This facility can also make use of local brackish groundwater as a base for fracturing fluids. Unfortunately, this experience is not easily repeated in all areas or in all shale plays. Trace chemicals such as barium, strontium, and sulfate often represent a small fraction of the salts present in produced and brackish waters but may promote scaling and other operational characteristics. The chemistry of the produced and brackish waters is quite variable, and conditions that may allow use of these waters for some fracturing operations may not exist in different areas within even a single shale play. The challenges in using poor quality waters include understanding the variability from a particular water source, the increased cost of fracturing fluid treatment additives (to achieve gelling or viscosity control), the cost of transporting water from point of generation to point of use, and the increased severity and risk of surface spills. Even modest treatment or transportation costs lead to a strong incentive to dispose of produced water near the point of generation and to purchase water, even freshwater, near the point of use from other sources. On-site storage or treatment of poor quality waters also increases the potential for spills or leaks that could lead to further environmental impacts. These are discussed in more detail later in this chapter. Despite these barriers, increased use of alternative waters is desirable.

Use of brackish groundwater and produced water for hydraulic fracturing can reduce freshwater use. Increased use of these waters, however, can potentially increase impacts to land and water due to spills and leaks.

Research and testing to enable the use of brackish groundwater and

produced waters for hydraulic fracturing should be encouraged.

In the past, there were regulatory disincentives to transferring water from one production site to another operating site where water was needed for hydraulic fracturing. These have been relaxed by recent rule changes by the Railroad Commission of Texas (RRC), allowing off-lease use of water for recycling purposes (or for use as a fracturing fluid)—Statewide Rule 8 and Chapter 4, Subchapter B, Commercial Recycling—but it is not yet known if this rule change encourages significant increases in use of produced waters.

Recent Railroad Commission of Texas rules to encourage recycling should be tracked, and their effectiveness for promoting increased use of produced water should be evaluated.

An additional disincentive to using produced water for hydraulic fracturing is sometimes associated with leases requiring that the lessee purchase water from the landowner. Groundwater rights are controlled by surface owners in Texas, and there is a general lack of legal recognition that groundwater is a shared resource among adjacent landowners. This may pose less of a problem for expanding the use of brackish groundwater that could also be purchased from the landowner, but often these agreements are not disclosed and the extent of brackish groundwater use is not well known or understood.

A barrier to expanding the use of brackish groundwater for hydraulic fracturing is the lack of information on production characteristics in most brackish aquifers. Locations of brackish aquifers are generally known, but the productivity of these aquifers (e.g., transmissivity and storage potential of the formation) generally is not well known. Furthermore, the quality of brackish groundwater, and how that quality may change with time or production rates, is not well known. Currently, as a result of the 84th Texas Legislative Session, under House Bill 30, the Texas Water Development Board is tasked with studying seawater and brackish groundwater resources, which should increase knowledge of these topics.

Aquifer investigations including pumping tests and chemical analyses should be used to better characterize the productivity and chemical composition of brackish groundwater, and variability of these properties, in oil and gas producing areas.

Finally, recognizing the trade-offs associated with using poor quality waters rather than freshwater or potable is important. The task force was not aware of any risk assessment or cost studies that compare deep well disposal of wastewater to use of produced water for hydraulic fracturing fluid considering transportation, storage, and on-site processing. Thorough comparative assessments of alternative water sources ideally would address the potential replacement, where possible, of deep well wastewater disposal by other management options, considering potential downsides including increased traffic accidents from higher trucking mileage, potential surface spills, etc. Examples of some of the trade-offs associated with the various approaches to sourcing and managing water used for fracturing are presented in Table 6-2.

Further research on the broad life-cycle risks related to water management decisions should be conducted. This research should recognize trade-offs among water use sectors, and provide a basis for balancing increased use of poor-quality waters with freshwater use for new hydraulic fracturing activities.

TABLE 6-2 Examples of trade-offs associated with various approaches to sourcing and managing water used for hydraulic fracturing activities.

Action or activity	Potential positive and negative impacts on other factors
Increased use of brackish ground water for oil and gas exploration and production	Develops and exploits brackish water resources Diverts potential drinking water sources to industrial applications Groundwater sales to operators often provides additional financial benefits to landowners or communities Potential for spills of brackish water
Increased use of produced water for fracturing operations	Reduced need for freshwater, sustaining freshwater supplies Potential increase in storage and truck transport of brine water, increasing risks of accidental release Reduced need for deep well disposal, reducing potential for inducing seismicity in some areas
Increased use of pipelines for transporting fluids	Reduced truck traffic, reducing road wear and community impacts Reduced likelihood of accidental spills from above-ground water storage facilities (e.g., tanks, impoundments, etc.) Increased land fragmentation from pipeline construction

SUBSURFACE CONTAMINATION DUE TO MIGRATION OF FRACTURING OR FORMATION FLUID

A second major concern about hydraulic fracturing is whether the fractures increase connectivity of drinking water and non-potable groundwater in the subsurface or may directly contaminate drinking water aquifers. Fracturing fluids, which contain a variety of chemicals designed to tailor the properties of the injected water to maximize oil and gas well productivity, may be of concern if they were to migrate to drinking water aquifers.

Slick water fracturing fluids have the simplest chemistry and may include only a friction reducer (e.g., a light petroleum distillate perhaps with an emulsifier to aid dispersion in the fluid), a scale inhibitor (methanol or ethylene glycol), an iron control agent (e.g., citric acid) or other fouling control agent (e.g., hydrochloric acid), and a biocide (e.g., glutaraldehyde). Bacteria and iron can pose substantial problems in fracturing fluid because iron can precipitate as a result of bacterial oxidation/reduction processes and foul (plug) a well. Slick water fracturing fluids are relatively insensitive to the water quality used to generate the fracturing fluid and are therefore more easily adapted to brackish and/or produced water.

Gel fracturing fluids are considerably more complicated and include gelling agents and crosslinkers as well as other chemicals including biocides, scale inhibitors, and iron control agents to tailor the fluid properties and achieve the desired gelling characteristics. Gel fracturing fluids are sensitive to water properties that might reduce effectiveness of the gelling and crosslinking agents. Regardless of the type and components of the fracturing fluid, it is designed to be prepared at the surface and injected into the oil- or gas-bearing formation. As with other fluids at an oil and gas production site, including oil or produced water, fracturing fluid can cause negative environmental consequences if spilled at the surface or injected where it can migrate into drinking water aquifers. The potential consequences of near-surface or surface spills of oil and gas production-related fluids will be discussed in the next section. This section considers the consequences of injection into oil- and gas-bearing formations and the potential for migration into other strata or development of interconnectivity between strata.

The potential for migration of fracturing fluid, formation waters, or oil and gas into potential drinking water sources is a frequently cited concern regarding the hydraulic fracturing process. The fracturing process is designed to open flow and transport pathways in the subsurface, so it is perhaps natural to be concerned about migration of these fluids into drinking water aquifers. During hydraulic fracturing, fluid is injected to fracture the formation. Because the principal stress is in the vertical direction in the relatively deep oil- and gas-producing formations in Texas, the fractures (which form and propagate perpendicular to minimum stress direction) also tend to propagate vertically. Some hydraulic fracture treatments in Texas have taken place near the base of protected water, and the RRC considered the possibility of pollution enough of a risk that in 2013 it amended its rules to require additional oversight for hydraulic fracturing within 1,000 feet of the base of protected water.

The Eagle Ford formation is typically 250 feet thick, 4,000 to 12,000 feet below ground surface, and 2,800 to 10,800 feet below the base of overlying treatable water. The Barnett Shale is a 100 to 600-foot thick layer located 6,500 to 8,500 feet beneath the surface, and 5,300 to 7,300 feet below the base of overlying treatable water. By comparison, microseismic and micro-deformation field monitoring techniques suggest that the typical heights of fractures after hydraulic fracturing are in the tens to hundreds of feet.

The depth separation between oil-bearing zones and drinking water-bearing zones in Texas makes direct fracturing into drinking water zones unlikely, and it has not been observed in Texas.

This low likelihood can be contrasted with oil and gas production in some areas outside of Texas, such as from coalbed methane or in shallow formations, where fracturing may be sufficiently close to potential water sources to be of concern. Recent studies have shown that the occasional detection of methane in shallow aquifers appears to be unrelated to hydraulic fracturing deep in the subsurface ("at depth"), although this sometimes is associated with migration from deep formations associated with natural faults (Nicot et al., 2017a, 2017b, 2017c).

Of potentially greater concern in Texas and elsewhere is the presence of other wells, some plugged and abandoned for decades, which may contribute to well communication and fluid migration. In 2012, for example, a horizontal well in Alberta, Canada, was hydraulically fractured and caused a nearby vertical well (within approximately 400 feet and completed at 6,000 feet depth) to become a conduit for fluids to reach and spill onto the surface. In that instance, well field conditions were not designed to manage the increased pressures due to the fracturing (Energy Resources Conservation Board of Canada, 2012). Greater vertical migration of fracturing or formation fluids may also occur if a hydraulic fracture intersects natural fault or fracture networks. A microseismic survey showing apparent hydraulic fracture height of nearly 2,000 feet may instead have been related to a shallower natural fracture network (Davies et al., 2012). Even this depth, however, is less than the distance between the targeted zone and the base of an underground source of drinking water in Texas formations. This evidence suggests that any direct impacts of fracturing or formation fluids on potential drinking water zones in Texas are more likely to be caused by near surface leaks during injection or production, or by spills at the surface rather than migration from the point of injection.

Direct migration of contaminants from targeted injection zones is highly unlikely to lead to contamination of potential drinking water aquifers. The collection and sharing of pressure data relevant to communication between water-bearing and producing strata—including non-commercial flow zones—or across wells could help identify and avoid potential concerns.

SPILLS OF FLOWBACK WATER, DRILLING FLUID, AND FORMATION WATER AT OR NEAR THE SURFACE

As described in the preceding section, **surface spills and well casing leaks near the surface are the most likely pathways for oil and gas activities to lead to contamination of drinking water sources and environmental damage.**

These are not uniquely related to hydraulic fracturing since all oil and gas wells generate fluids, including water, that must be managed at the surface with a resulting potential for spills and leaks. In some older oil fields in Texas, such as many in the Permian Basin, produced water volume is substantially greater than the volume of oil produced or water injected for hydraulic fracturing.

A critical component of an oil and gas well in controlling fracturing fluid or formation fluid leaks is the casing and cement used to construct the well. Surface casing that forms a steel barrier, which is further reinforced by a cement seal, extends through the depth of the potential drinking water aquifers and is the first line of protection for that resource. Additional casing is extended into the oil and gas production zone. If this casing is inadequate or fails, fracturing or formation fluid can bypass the cement bond or casing, and either leak into the surrounding formation or be carried back up to the surface where it results in a surface spill. For example, inadequate casing led to a prominent, well-studied failure in Bainbridge, Ohio, in 2008 (Ohio DNR, 2008). In that instance, incomplete casing cementing led to a return of fracturing fluid to the ground surface. This failure also caused upward migration of methane from near surface zones, leading to contamination of drinking water wells and an accumulation of gas setting off an explosion in a nearby home.

More often, casing problems result in leaks with less spectacular impacts. If casing designs include multiple layers, leaks may simply lead to communication between annular layers, with no exposure to the surrounding environment. In a study of 211 groundwater contamination incidents in Texas associated with oil and gas activity (Kell, 2011), only 10 incidents were associated with well drilling and completion and none were associated with stimulation (hydraulic fracturing). Moreover, many of the noted incidents occurred prior to 1969 and before the RRC revised regulations on cementing. Continued improvements in cementing and casing pressure monitoring are intended to further reduce the occurrence of these types of incidents. However, because of the industrial nature of this activity, there is, and always will be, some probability of casing failure leading to near surface contamination or contributing to surface spills due to flow up the failed casing.

More commonly, events are associated with spills or leaks at ground surface. Spills have also been associated with flooding at the surface (Schladen, 2016). These may be associated with equipment or operational failures during drilling, completion, or production. Fluid transfers (transportation or flowlines) and storage areas (tanks and pits) offer particular risks for spills of fracturing fluid, formation fluids, or flowback water. The EPA has estimated that 5 to 7 saltwater spills occur per 100 producing wells (EPA, 2016). The median spill volume was approximately 1,000 gallons although large spills of more than one million gallons have occurred. The EPA also found that 38 percent of the spills they tracked were caused by human error and 30 percent by equipment or container failure (the remainder were miscellaneous small sources or unknown). Many of these spills are typically contained within the boundaries of the facility or wellhead. A study in North Dakota showed that of 734 oil spills and 552 saltwater spills between November 2012 and November 2013, 67 percent of the oil spills and 81 percent of the saltwater spills were contained onsite (NDDH, 2013).

The evaluation of spill frequency, causes, and impacts is made difficult by different reporting volumes in different states. North Dakota requires spills as small as one barrel (42 gallons) to be reported and thus typically shows more spills than other states having a larger reporting threshold. An increasing number of states require reporting of spills or leaks in excess of one barrel. The volume required to be reported may not need to be that small (since much higher volumes would typically be required to lead to significant surface or subsurface contamination), but it needs to be small enough to allow characterization of the sources of spills to guide improvements in operations and equipment. Spills and leaks are most common in the first year of the well life-cycle and tend to decrease after that time. Although most spills were small and easily managed with minimal environmental damage, others were substantial, leading to more lasting environmental damage.

There has been less comprehensive reporting on spill and leak frequency and causes on operations in Texas. Spills of oil into water that result in sheens must be reported, but the reporting threshold is 5 barrels of oil onto land. Although brine can contaminate soil and can harm vegetation, there are no statewide reporting requirements for these spills. Although most RRC districts ask for reporting of brine spills, it is not formally required by rules. Further, reporting thresholds vary across districts, ranging from approximately 25 to 100 barrels. This is larger than the median brine spill observed in North Dakota, suggesting that such a threshold provides limited opportunity to identify any recurring causes of the leaks. Most national-level analyses, including those cited above, evaluate spills and leaks in other states where the spill volume reporting threshold is smaller than in Texas and where reports are more accessible (e.g., online).

Information on spills and leaks from oil and gas activities in Texas is less accessible and detailed than in some states, potentially limiting the ability to identify sources and root causes. Statewide leak and spill reporting requirements for produced water should be considered. For all spilled substances, reporting requirements should be improved to aid identification of the primary sources of leaks and appropriate management responses.

Impacts to surface water or land resources from surface spills, both of which are visible to the public, likely contribute significantly to any negative public opinion of oil and gas operations. The cause of these spills or leaks may stem from near surface well casing failures or equipment or operational failures at or near ground surface. The primary approach to more effectively managing these failures is the full implementation of appropriate best management practices for operations and risk management.

Texas regulators and industry should continue to develop and apply best management practices relative to well casing design and construction, and surface management of oil and gas operations, to reduce inadvertent release of fluids.

WASTEWATER TREATMENT, USE, AND DISPOSAL

For conventional oil and gas operations, the largest volume of fluids generated from a producing well often is associated with formation water rather than oil. In hydraulic fracturing operations there is additional water returned to the surface as flowback water.

"Flowback" may be defined broadly as water that was injected as hydraulic fracturing fluid, while formation water originated in the subsurface. The rate of produced water and the relative proportion of flowback versus formation water differ substantially by oil and gas production area as does the quality. The quantity and quality of produced water is highly variable across the United States (see Veil, 2015 for a summary of volumes of produced water). In the Permian Basin, far more water is generated over the lifetime of a well than is initially injected for hydraulic fracturing. In the Barnett Shale region, the amount of produced and injected water are in approximate balance over the lifetime of a well (Nicot et al., 2014). In the Eagle Ford region, only a small fraction of the water injected ultimately returns to the surface (Nicot and Scanlon, 2012; Scanlon et al., 2014a; Scanlon et al., 2014b).

After the first few days of production in shale reservoirs, most of the produced water originates in the formation and exhibits a composition controlled by the characteristics of the formation. Even the initial volumes of flowback water produced by a given well, however, frequently have much poorer quality in terms of dissolved and suspended solids than the injected fracturing fluid. In Texas, both flowback and formation waters are of extremely poor quality with dissolved salts or solids typically in excess of 100,000 mg/l. This contrasts with seawater with a dissolved salts content of 32,000 to 34,000 mg/l. This sharply limits the management options for this water and has led to the vast majority of it being injected in deep salt water disposal wells (a summary of produced water management practices in the United States is available in Veil, 2015).

Most of the volumes of water that must be disposed of are not directly connected to the amount of fracturing fluid injected. Many wells that produce substantial amounts of water are not hydraulically fractured. Ten barrels of water are commonly associated with a single barrel of oil produced in the Permian Basin regardless of well development procedures. The presence of some 7,500 permitted and operating salt water disposal wells in Texas largely predate the increase in hydraulic fracturing associated with shale development. However, specific areas of Texas have seen dramatic growth in oil and gas activities due to hydraulic fracturing, and thus are experiencing greater disposal activity as well.

The poor quality of produced water from Texas oil and gas fields limits both the options for beneficial use and increases the negative impacts associated with spills or leaks. In contrast, produced water from coal bed methane wells in Colorado and from some California oil and gas wells is of much better quality, and relatively low cost treatment efforts could allow produced water to be directed toward agriculture or other beneficial use. The very high salinity of most produced waters in Texas limits the economic viability of treatment options for any beneficial use.

Produced waters have been used successfully in fracturing new wells, either directly or after blending with fresh or brackish water. As indicated previously, however, the volumes used are modest due to the logistical challenges and spill and leak risks associated with transporting the water to a well to be fractured; concerns about potential incompatibilities and scaling issues; and the need for treatment to remove oil, some solids, iron, and scale-forming salts to allow use in gel-based fracturing fluids.

Water demands are high in many oil and gas producing regions of Texas, particularly the Permian Basin and Eagle Ford play. These demands could open potential opportunities for treatment of produced water for expanded use if the produced water were not so very saline. Alternatives, such as brackish groundwater in inland areas and seawater in coastal areas are much more cost-effectively treated, discouraging the use of produced water for this purpose. Much of the cost of desalination is associated with the energy costs of separating salts; the energy requirements are directly proportional to the concentration of the salts in the feed waters. Thus, water that typically contains 1,000 to 3,000 mg/l dissolved salts can generally be more cost-effectively upgraded for agricultural and other uses than seawater or produced water from oil and gas plays. There are also concerns about the potential negative impacts of trace contaminants in produced water that might limit their beneficial use outside of oil and gas activities.

Risks due to spills and leaks may increase with the complexity and volumes of fluids managed at the surface. Treatment and use of produced water for fracturing operations or other beneficial use thus may increase the possibility of spills and leaks. These facts should be considered when evaluating options for produced water and comparing disposal versus beneficial use options.

Texas officials and experts also may wish to consider relevant experiences outside the state that may offer lessons for useful approaches and actions for Texas. For example, Oklahoma has extensive experience in oil and gas exploration and development, and they have been studying water reuse and disposal issues. A 17-member team in Oklahoma, the Produced Water Working Group (PWWG) and led by the Oklahoma Water Resources Board, was tasked with studying and recommending alternatives to produced water disposal from oil and gas operations. The recommendations in the team's report are part of a long-term effort to improve Oklahoma water management (Oklahoma Water Resources Board, 2017). The report addresses water treatment and reuse topics that could be of interest and value to decision makers, industry, and other experts in Texas studying and developing improved water reuse and management programs and technologies. **In Texas, both economics and risk considerations dictate that much of the produced water will continue to be injected in deep wells or used as fracturing fluid to minimize impacts on other water sources.**

There are locations, however, where local injection well challenges, including lack of disposal wells or the potential for induced seismicity, or local opportunities for direct use, may encourage minimal treatment and beneficial use of the produced water.

Although the volumes likely to be directed toward other uses is small, **research on techniques for cost-effectively treating produced water, particularly for uses that have minimal quality requirements, such as for hydraulic fracturing, should be continued.**

Additional research to evaluate potential negative impacts of any such uses also should be undertaken.

SUMMARY

Some of the most significant public concerns surrounding the application of hydraulic fracturing operations regards possible effects on both the available supply of water and possible effects on water quality. Millions of gallons of water are used to fracture a single well. Nevertheless, overall water use by hydraulic fracturing is small compared to that used by agriculture or municipalities. The amount of water used for hydraulic fracturing can be important, however, in areas where water use is otherwise low, such as rural energy-producing counties. The impact of water use on supply can be reduced by limiting freshwater use and using brackish groundwater or produced water for hydraulic fracturing.

Hydraulic fracturing is also a potential concern to drinking water supplies. There is little chance of migration of hydrocarbons or brines from producing formations to drinking water aquifers, but near surface and surface spills or leaks may pose the dominant risk of hydraulic fracturing operations to water resources. Increased complexity of surface fluid management, for example by treatment and use/reuse operations, may increase the potential for spills or leaks and therefore the risk to land and water resources.

Chapter findings and recommendations relative to water management are summarized below.

Findings

- **Water used in hydraulic fracturing processes in Texas represents a small fraction—less than 1 percent—of total water use statewide. In some regions and locales in Texas, however, water used in hydraulic fracturing represents a significantly larger proportion of local water sources.**
- **Use of brackish groundwater and produced water for hydraulic fracturing can reduce freshwater use. Increased use of these waters, however, can potentially increase impacts to land and water due to spills and leaks.**
- **The depth separation between oil-bearing zones and drinking water-**

bearing zones in Texas makes direct fracturing into drinking water zones unlikely, and it has not been observed in Texas.

- **Surface spills and well casing leaks near the surface are the most likely pathways for oil and gas activities to lead to contamination of drinking water sources and environmental damage.**
- **Information on spills and leaks from oil and gas activities in Texas is less accessible and detailed than in some states, potentially limiting the ability to identify sources and root causes.**
- **In Texas, both economics and risk considerations dictate that much of the produced water will continue to be injected in deep wells or used as fracturing fluid to minimize impacts on other water sources.**

Recommendations

Water Availability and Supply

- **Research and testing to enable the use of brackish groundwater and produced waters for hydraulic fracturing should be encouraged.**
- **Recent Railroad Commission of Texas rules to encourage recycling should be tracked, and their effectiveness for promoting increased use of produced water should be evaluated.**
- **Aquifer investigations including pumping tests and chemical analyses should be used to better characterize the productivity and chemical composition of brackish groundwater, and variability of these properties, in oil and gas producing areas.**
- **Further research on the broad life-cycle risks related to water management decisions should be conducted. This research should recognize trade-offs among water use sectors, and provide a basis for balancing increased use of poor-quality waters with freshwater use for new hydraulic fracturing activities.**

Subsurface Contamination by Fracturing or Formation Fluid

- **Direct migration of contaminants from targeted injection zones is highly unlikely to lead to contamination of potential drinking water aquifers. The collection and sharing of pressure data relevant to communication between water-bearing and producing strata—including non-commercial flow zones—or across wells could help identify and avoid potential concerns.**

Spills of Flowback Water, Drilling Fluid, and Formation Water at the Surface

- **Statewide leak and spill reporting requirements for produced water should be considered. For all spilled substances, reporting requirements should be improved to aid identification of the primary sources of leaks and appropriate management responses.**
- **Texas regulators and industry should continue to develop and apply best management practices relative to well casing design and construction,**

and surface management of oil and gas operations, to reduce inadvertent release of fluids.

Wastewater Treatment and/or Disposal

- **Research on techniques for cost-effectively treating produced water, particularly for uses that have minimal quality requirements, such as for hydraulic fracturing, should be continued.**
- **Additional research to evaluate potential negative impacts of any such uses also should be undertaken.**

7

Transportation

- Current technologies for oil and gas development and production from shale formations require very large numbers of heavy truckloads. Most existing roadway and bridge infrastructure in Texas was not designed to carry or accommodate the current large numbers and weights of truckloads.
- Traffic increases—especially truck traffic—associated with the development and production of oil and gas from shale formations in Texas have resulted in increases in the frequency and severity of traffic crash incidents.
- The level of funding to address the impacts to the transportation infrastructure and traffic safety in the oil and gas industry area is low relative to the magnitude of the impact.
- Strategies to improve the state's preparedness include, but are not limited to, 1) improving the availability and quality of data related to ongoing and forecasted drilling activities; 2) improving coordination among agencies at the state, county, and local levels; 3) developing integrated, multimodal transportation infrastructure strategies; and 4) identifying and allocating reliable, sustainable funding sources.

One of the effects of using horizontal drilling and hydraulic fracturing techniques to extract oil and gas resources has been a significant increase in traffic volumes, especially in rural areas where most of the well development and production activities take place. These traffic increases have been particularly noticeable in the form of large numbers of heavy trucks providing transportation services.

Roadways are not the only mode of transportation experiencing increased traffic volumes. Other modes of transportation have also experienced a surge in traffic, as evidenced by the significant increase in energy-related activities at transportation facilities such as ports, railroads, and pipelines. The increase has been particularly evident in Texas, where, at any given time, the number of active drilling rigs accounts for 45 to 50 percent of all active rigs in the country (Baker Hughes, 2016). In many cases, transportation systems have also faced capacity constraints, resulting in additional traffic in other modes of transportation, such as when a lack of pipeline infrastructure results in additional truck and rail traffic to transport petroleum products.

Increased energy development activity and the corresponding increase in hydrocarbon production has created pressure on pipeline and rail infrastructure. Over time, the industry has begun to add new rail and pipeline capacity to absorb the additional demand. Generally, these changes in infrastructure capacity are planned and executed by the industry, with little influence or participation by the public sector. Public transportation infrastructure such as roads and ports is subject to considerably tighter financial constraints. This chapter focuses heavily on public transportation infrastructure because of the attention it has generated for the public, the legislature as well as state, county, and local agencies.

Transportation infrastructure does not exist in isolation. The relationship between transportation and other areas of the economy is both complex and dynamic. Not surprisingly, there is a close relationship between transportation and each of the other topics discussed in this report (Figure 7-1).

FIGURE 7-1 Interconnections among transportation and other topic areas in this report.

Most well development-related traffic in Texas occurs on rural roads. These rural roads, such as farm-to-market (FM) roads, ranch-to-market (RM) roads, and county roads, were never designed to carry the huge amount of truck traffic associated with energy developments. Most of these roads were built decades ago to serve mostly local, low-volume traffic needs, and not repetitive heavy truckloads. The result has been accelerated degradation of pavements and roadside infrastructure as well as increases in congestion, crash, and fatality rates. This chapter provides a summary account of these impacts. The chapter highlights areas where the body of knowledge has increased since the beginning of the energy upturn in the mid-2000s. It also suggests areas where research and technology transfer initiatives are necessary to increase the state's ability to manage its transportation system in response to oil and gas industry development activities.

TRUCK TRAFFIC VOLUMES AND TRUCKLOADS

Well development involves pad preparation, drilling, and hydraulic fracturing. Well operation includes the extraction of hydrocarbon products, oil, condensate and/or gas, and water as well as various maintenance activities. In addition to new well development, refracturing existing wells brings similar transportation demands that can occur at various times during the productive lifetimes of existing wells.

Anticipating transportation needs is difficult and relies on information from a variety of sources including literature reviews from around the country, state officials, and well counts and other statistics from the Railroad Commission of Texas (RRC) (Quiroga et al., 2015). It has also involved using data from sources such as the FracFocus database, which provides publicly accessible information of the amount of water, sand, and additives used for hydraulic fracturing operations (GWPC and IOGCC, 2014).

A standard metric to quantify truckloads for pavement design and maintenance is the 18,000-pound equivalent single axle load (ESAL). An 18,000-pound single axle corresponds to one ESAL (AASHTO, 1993). An equivalent axle load factor (EALF) defines the load per pass by the axle in question relative to the load per pass of an ESAL. The amount of truckload increases sharply with vehicle weight. For example, as shown in Table 7-1, with respect to an empty truck weighing 35,000 pounds, a loaded truck weighing 80,000 pounds (maximum legal limit in Texas) involves a weight ratio of 2.3 to 1, but the resulting EALF truckload ratio is 38 to 1 (Quiroga et al., 2012). With respect to a loaded truck weighing 80,000 pounds, a truck weighing 84,000 pounds (or 5 percent over 80,000 pounds, which is the allowable weight for annual overweight permits in Texas) involves a weight ratio of 1.05 to 1, but the corresponding truckload ratio is 1.2 to 1.

Similarly, a truck weighing 100,000 pounds involves a weight ratio of 1.25 to 1, but the corresponding truckload ratio is 2.4 to 1. In other words, although the increase in weight from 80,000 pounds to 100,000 pounds is 25 percent, the increase in pavement impact is 140 percent.

TABLE 7-1 Relative Truckload as a Function of Gross Vehicle Weight.

Gross Vehicle Weight (lb)	Weight Ratio	EALF Ratio	Weight Ratio	EALF Ratio	Weight Ratio	EALF Ratio
	With respect to 4,000 lb		With respect to 35,000 lb		With respect to 80,000 lb	
4,000	1	1				
10,000	2.5	23				
35,000	8.8	583	1	1		
80,000	20	18,009	2.3	31	1	1
84,000	21	22,210	2.4	38	1.05	1.2
90,000	22	28,511	2.6	49	1.12	1.6
100,000	25	42,753	2.9	73	1.25	2.4

SOURCE: Quiroga et al., 2012.

The number of trucks needed to develop and operate oil and gas wells varies depending on the region in the state where energy development is taking place. Table 7-2 summarizes the number of trucks needed to develop a well in the Eagle Ford Shale, Barnett Shale, and Permian Basin regions. Tables 7-3 through 7-5 summarize the results of ESAL calculation analysis for each region (which presumes that trucks are used solely to transport materials and supplies to the site, and to transport waste off-site).

TABLE 7-2 Number of Trucks Needed to Develop a Well.

Well Development	Number of Trucks		
	Barnett Shale	Eagle Ford Shale	Permian Basin
Drilling pad and construction equipment	70	70	70
Drilling rig, equipment, materials, and fluid	117	117	117
Fracturing equipment: pump trucks, tanks	74	74	74
Fracturing water	533	1,021	527
Fracturing sand	57	147	66
Other additives and fluids	4	24	11
Flowback water removal	133	255	132
Total	**988**	**1,708**	**997**

SOURCE: Quiroga et al., 2016.

TABLE 7-3 Number of Trucks and ESALs per Well (Barnett Shale Region).

Item	Development	Production		Re-Fracturing		Total
		Per Year	Total	Per Event	Total	
Number of trucks	988	66	1,320	801	3,205	5,513
ESALs (trip to well)	1,363	5	98	1,070	4,281	5,742
ESALs (trip from well)	474	93	1,864	423	1,694	4,031

SOURCE: Quiroga et al., 2016.

TABLE 7-4 Number of Trucks and ESALs per Well (Eagle Ford Shale Region).

Item	Development	Production		Re-Fracturing		Total
		Per Year	Total	Per Event	Total	
Number of trucks	1,708	418	8,366	1,521	6,085	16,160
ESALs (trip to well)	2,261	31	625	1,968	7,871	10,757
ESALs (trip from well)	689	591	11,815	639	2,555	15,059

SOURCE: Quiroga et al., 2016.

TABLE 7-5 Number of Trucks and ESALs per Well (Permian Basin Region).

Item	Development	Production		Re-Fracturing		Total
		Per Year	Total	Per Event	Total	
Number of trucks	997	349	6,975	810	3,239	11,211
ESALs (trip to well)	1,381	26	519	1,089	4,354	6,254
ESALs (trip from well)	472	492	9,850	422	1,689	12,011

SOURCE: Quiroga et al., 2016.

Tables 7-1 and 7-2 provide another way of visualizing the relative pavement impact associated with the development of oil and gas wells. An average passenger car weighs around 4,000 lbs. As shown in Table 7-1, the total pavement impact due to a loaded truck weighing 80,000 lbs is 18,009 times greater than the impact of a vehicle weighing 4,000 lbs. Assuming 1,200 loaded trucks are needed to develop a typical well, the result would be 21.6 million times greater. In other words, developing a typical oil or gas well would be the rough equivalent of more than 20 million passenger cars in terms of the resulting pavement impacts.

Current technologies for oil and gas development and production from shale formations require very large numbers of heavy truckloads.

PAVEMENT IMPACTS

The correlation between heavy truck traffic and pavement deterioration has been known for decades, but most of the documentation of the extent of the impact due to shale development activities is relatively new. In response to the oil upturn in the late 1970s and early 1980s, a research study estimated the reduction in pavement serviceability and associated cost for Texas roads in relation to oil field traffic (Mason, 1983). More recently, in response to the increase in well development activities in the Barnett Shale region in North Texas in the mid- to late-2000s, a study reported on the number and type of trucks needed to develop well sites in Texas (Quiroga et al., 2012). By analyzing Texas Department of Transportation (TxDOT) Pavement Management Information System (PMIS) data, the study also found that well development activities accelerated the deterioration of pavement structures on roads in the well development and production areas.

Another study used a mechanistic-empirical pavement design approach to quantify the additional damage due to well development trucks based on segments selected from overweight permit data in Texas (Prozzi et al., 2011). The damage included rutting, longitudinal cracking, and alligator cracking. Some examples of pavement deterioration resulting from energy development activities in other parts of the country are also available in the transportation impacts literature (Sheetz et al., 2013; Meadors and Wright-Kehner, 2013).

Roadway infrastructure impacts include both pavement structure impacts and roadside impacts. Figure 7-2 and Figure 7-3 provide examples of both types of impacts. Several efforts have been undertaken to estimate the reduction in pavement life and corresponding economic impact. For example, a 2012 analysis estimated the cost to repair only secondary state roads at about $600 million per year (Quiroga et al., 2012). A subsequent analysis expanded the assessment to county and local roads and arrived at $1.5 to $2 billion per year (Cooner et al., 2013). Costs to the trucking industry are also significant. A preliminary evaluation of the cost in the form of additional vehicle damage and lower operating speeds estimated the cost at $1.5 to $3.5 billion per year (Fry et al., 2013).

FIGURE 7-2 Shoulder patches on FM 2257 near saltwater disposal facility in Parker County.
SOURCE: Quiroga et al., 2012.

FIGURE 7-3 Pavement shoving, loss of surface (IH 35W – frontage road)
SOURCE: Quiroga et al., 2012.

Most existing roadway and bridge infrastructure in Texas was not designed to carry or accommodate the current large numbers and weights of truckloads.

TRAFFIC SAFETY IMPACTS

The correlation between traffic increases in shale development areas and crash and fatality rates is only now being understood. In 2015, an analysis documented changes in crash trends in relation to oil and gas energy developments in Texas (Quiroga and Tsapakis, 2015). Table 7-6 shows changes in the number of crashes on all highways from 2006 to 2009 and 2010 to 2013. Overall, changes were not uniform either by crash location and type of vehicles involved or by injury severity. There were also significant differences geographically within each region, particularly in the case of rural crashes. The changes were even more pronounced for crashes that involved commercial motor vehicles (CMVs) and, particularly, for rural crashes that involved CMVs.

TABLE 7-6 Changes in Number of Crashes by Crash Severity.

Region	Number of Fatal, Incapacitating, Non-Incapacitating, Possible Injury, No-Injury, Unknown Crashes											
	All			Rural			CMV			Rural & CMV		
	2006-09	2010-13	Diff.	2006-09	2010-13	Diff.	2006-09	2010-13	Diff.	2006-09	2010-13	Diff.
Barnett Shale	184,735	166,474	-10%	24,572	18,521	-25%	14,119	12,367	-12%	3,130	2,061	-34%
Eagle Ford Shale	85,964	86,744	1%	27,660	28,804	4%	6,607	8,708	32%	2,820	4,542	61%
Permian Basin	80,891	77,511	-4%	15,689	17,426	11%	4,775	6,368	33%	2,464	3,743	52%
Other	1,410,907	1,306,749	-7%	288,715	284,431	-1%	90,081	77,755	-14%	26,221	23,942	-9%
Grand Total	**1,762,497**	**1,637,478**	**-7%**	**356,636**	**349,182**	**-2%**	**115,582**	**105,198**	**-9%**	**34,635**	**34,288**	**-1%**
Region	**Number of Fatal, Incapacitating, Non-Incapacitating Crashes**											
	All			Rural			CMV			Rural & CMV		
	2006-09	2010-13	Diff.	2006-09	2010-13	Diff.	2006-09	2010-13	Diff.	2006-09	2010-13	Diff.
Barnett Shale	31,739	30,728	-3%	5,346	4,165	-22%	2,124	1,846	-13%	642	474	-26%
Eagle Ford Shale	14,382	15,264	6%	6,889	6,948	1%	1,096	1,641	50%	662	1,173	77%
Permian Basin	11,520	12,019	4%	3,841	4,524	18%	883	1,333	51%	617	971	57%
Other	204,134	201,541	-1%	57,296	54,123	-6%	12,568	11,792	-6%	4,998	4,751	-5%
Grand Total	**261,775**	**259,552**	**-1%**	**73,372**	**69,760**	**-5%**	**16,671**	**16,612**	**0%**	**6,919**	**7,369**	**7%**
Region	**Number of Fatal Crashes**											
	All			Rural			CMV			Rural & CMV		
	2006-09	2010-13	Diff.	2006-09	2010-13	Diff.	2006-09	2010-13	Diff.	2006-09	2010-13	Diff.
Barnett Shale	1,202	1,030	-14%	459	325	-29%	181	135	-25%	101	63	-37%
Eagle Ford Shale	851	902	6%	629	694	10%	129	204	58%	102	179	76%
Permian Basin	648	789	22%	430	518	20%	94	183	94%	80	151	88%
Other	9,465	8,954	-5%	4,673	4,293	-8%	1,177	1,170	-1%	663	684	3%
Grand Total	**12,166**	**11,675**	**-4%**	**6,191**	**5,830**	**-6%**	**1,582**	**1,692**	**7%**	**946**	**1,077**	**14%**

SOURCE: Quiroga et al., 2012.

In most cases, as the severity of the injuries worsened, the changes in the corresponding number of crashes were more pronounced. For example, for rural crashes that involved CMVs in the Eagle Ford Shale region, there was a 77 percent increase in the number of fatal, incapacitating, and non-incapacitating (KAB)[11] injury crashes (compared to a 61 percent increase for all crashes). For fatal crashes, the increase was 76 percent. In the Permian Basin region, there was a 57 percent increase in the number of KAB crashes (compared to a 52 percent increase for all crashes). For fatal crashes, the increase was 88 percent. In the Barnett Shale region, there was a reduction in the number of CMV crashes, which corresponds to a reduction in the number of gas wells completed in the region.

The analysis included an evaluation of economic and comprehensive costs associated with the changes in crash trends (National Safety Council, 2015). Economic costs rely on calculable costs such as wage and productivity losses, medical expenses, administrative expenses, motor vehicle damage, and employers' uninsured costs. They do not measure the value of lost quality of life. Comprehensive costs include both the economic cost components above and a measure of the value of lost quality of life, and are therefore appropriate to use as a reference to analyze the anticipated benefit of future improvements (because they provide a measure of what people would be willing to pay for improved safety).

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[11] KAB is an acronym in which K refers to the number of fatal crashes, A refers to the number of incapacitating injury crashes, and B refers to the number of non-incapacitating injury crashes.

As shown in Table 7-7, in the Eagle Ford Shale region, there was a 52 percent increase in costs ($139 million in economic costs and $419 million in comprehensive costs) from 2006 to 2009 and 2010 to 2013. In the Permian Basin region, there was a 103 percent increase in costs ($176 million in economic costs and $539 million in comprehensive costs). In the Barnett Shale region, there was a decrease in economic and comprehensive costs because of fewer rural CMV crashes and fewer resulting injuries.

TABLE 7-7 Changes in Economic and Comprehensive Costs for Injuries Occurred in Rural CMV-Related Crashes.

Region	Economic Cost			Comprehensive Cost		
	2006-09	2010-13	Diff.	2006-09	2010-13	Diff.
Barnett Shale	$ 211,795,179	$ 138,404,870	-35%	$ 640,098,771	$ 417,982,017	-35%
Eagle Ford Shale	$ 268,959,920	$ 407,742,394	52%	$ 809,729,658	$ 1,228,722,169	52%
Permian Basin	$ 171,025,104	$ 347,503,582	103%	$ 513,260,764	$ 1,051,857,637	105%
Other	$ 1,614,666,206	$ 1,567,187,786	-3%	$ 4,827,962,078	$ 4,701,875,857	-3%
Grand Total	**$ 2,266,446,409**	**$ 2,460,838,632**	**9%**	**$ 6,791,051,271**	**$ 7,400,437,680**	**9%**

SOURCE: Quiroga and Tsapakis, 2015.

Traffic increases—especially truck traffic—associated with the development and production of oil and gas from shale formations in Texas have resulted in increases in the frequency and severity of traffic crash incidents.

Changes in crash rates have been more pronounced for crashes involving trucks and, particularly, for rural crashes that involve trucks. In most cases, as the severity of the injuries resulting from these crashes worsens, the changes in the corresponding number of crashes have been more pronounced. The result has been a higher percentage in the number of fatal, incapacitating, and non-incapacitating injury crashes in energy development regions compared to overall changes for all types of crashes. The annual cost associated with the increase in crashes has been estimated between $50 to $150 million per year.

ECONOMIC IMPACTS

The previous section presented dollar figures of annual damages to pavement structures. The economic impact associated with crashes is also significant. Statewide, the annual cost of rural crashes that involve commercial vehicles, which could be attributed to an increase in traffic due to energy developments, ranges from $48 million in economic costs to $152 million in comprehensive costs (Quiroga and Tsapakis, 2013).

Additional economic impacts associated with other modes of transportation have not been quantified. Other economic impacts directly related to road transportation that have not been quantified include, but are not limited to, the following:

- air quality impacts;
- transportation of equipment, materials, and supplies;
- transportation of water, including drilling, hydraulic fracturing, flowback, and produced waters;
- transportation of crews; and
- emergency management, evacuations, spills, and other similar events.

Funding allocation to address these impacts is considerably lower than the magnitude of the impact. For example, funding allocations at the state level for roadway improvements have been as follows:

- 2012 maintenance funds ($40 million);
- 2013 House Bill 1025 ($225 million for design-build and traditional letting);
- 2014 rural needs ($500 million);
- 2014 safety, maintenance, and oil and gas sector, including $200 million (safety) and $200 million (maintenance and oil and gas sector); and
- 2015 Proposition 1 funding ($1.74 billion), including $696 million (connectivity), $522 million (regional corridors), $261 million (oil and gas sector), and $261 million (maintenance).

Budget allocations at the local and county levels have not been quantified as of this report's release date.

The level of funding to address the impacts to the transportation infrastructure and traffic safety in the oil and gas industry area is low relative to the magnitude of the impact.

In recent years, the Texas Legislature has allocated funds to address some of the most critical needs. In some cases, counties and local jurisdictions have also been able to make use of a limited amount of funds based on increased tax revenues to address urgent transportation system challenges. However, for the most part, the unmet needs continue to exceed the availability of the existing funds.

CURRENT INITIATIVES

Several initiatives are underway to document impacts to the transportation system or to provide recommendations on how to address those impacts. Worth noting is an effort at TxDOT that produced a significant number of guidance and implementation reports designed to improve pavement maintenance and rehabilitation practices in the oil and gas industry (TxDOT, 2016). Table 7-8 provides a summary of reports that resulted from this initiative.

Another initiative is a research project currently funded by TxDOT, which is examining the use of temporary pipelines to carry water used for hydraulic fracturing operations (TxDOT, 2017). Using temporary pipelines has increased significantly over the last few years, particularly in the Eagle Ford Shale region. In practice, TxDOT districts have observed a wide range of practices related to the installation, operation, and maintenance of these facilities. The purpose of the research is to examine current practices and to develop engineering guidelines for permitting, installing, operating, and maintaining temporary pipelines within the state right of way.

TABLE 7-8 Reports from TxDOT's Initiative.

Report Type	No.	Description
Research Report	RR-13-01	Action plan and summary for roads to gravel-energy sector and heavy commercial development
	RR-14-01	Maintenance and rehabilitation strategies for repair of road damage associated with energy development and production
	RR-14-02	Analysis of paved shoulder width requirements
	RR-14-03	Pavement design catalog development for pavements in energy affected areas of Texas
	RR-15-01	Truck traffic and truckloads associated with unconventional oil and gas developments in Texas
	RR-16-01	Truck traffic and truckloads associated with unconventional oil and gas developments in Texas-2016 update
	RR-16-02	Pavement performance
Implementation Report	IR-14-01	Current TxDOT practices for repair of road damage associated with energy development and production
	IR-15-01	Pavement design catalog development for pavements in energy affected areas of Texas
	IR-15-02	Project level pavement evaluation guidelines
	IR-15-03	Maintenance and rehabilitation strategies for repair of road damage associated with energy development and production
	IR-16-01	Descriptive statistics and well county maps
	IR-16-02	Truck axle weight distributions
	IR-16-03	Traffic loads for developing and operating individual wells
	IR-16-04	Traffic loads for segment and corridor-level analyses
	IR-16-05	Pavement performance

Report Type	No.	Description
Energy Sector Brief	ESB-14-01	TxDOT/TTI joint effort to address roadway damage resulting from energy development
	ESB-14-02	Recommended shoulder widths
	ESB-14-03	Shoulder/edge repair techniques
	ESB-14-04	Rehabilitating oil-field damaged roads with roamed asphalt
	ESB-15-01	Maintenance repair techniques
	ESB-15-02	Shallow patching
	ESB-15-03	Deep patching
	ESB-15-04	Level up patching
	ESB-15-05	Surface treatment/seal coat/chip seal
	ESB-15-06	Pavement strengthening
	ESB-16-01	Large aggregate surface treatment
	ESB-16-02	Selection of maintenance and rehabilitation strategies
	ESB-16-03	Project level pavement evaluation guidelines (JE)
	ESB-16-04	Pavement thickness design catalog with flexible base layer
	ESB-16-05	Pavement thickness design catalog with stabilized base layer
	ESB-16-06	Well county maps
	ESB-16-07	Truck axle weight distributions
	ESB-16-08	Traffic loads for developing and operating individual wells
	ESB-16-09	Traffic loads for segment and corridor-level analyses
	ESB-16-10	Performance of pavement in the energy sector

SOURCE: Texas Department of Transportation, 2016.

In 2015, three regional one-day workshops took place with the participation of public-sector and private-sector representatives in Arlington, Midland, and San Antonio to discuss short-term and long-term issues, and identify potential research ideas and implementation strategies (Quiroga, 2015). A critical goal of the three regional workshops was to address the relationship between transportation networks and energy developments in a holistic manner. To achieve this goal, the workshops included breakout sessions to address topics such as, but not limited to, industry and public outreach and communication, pavement structures, operations and safety, roadside management, asset management, planning, environment, and design.

The three regional workshops enabled the identification of 63 research topics that provided the foundation for a comprehensive transportation and energy system (CTES) framework and strategic research roadmap that included eight major interconnected themes (Figure 7-4) and 19 distinct research ideas. Research need statements were also prepared for each of the 19 research ideas. Details about the research plan and the research need statements are available online (Quiroga, 2015).

The CTES research map would involve a $9 million plan of research expenditures, including $2.2 million for overarching topics (i.e., research topics that involve other topics of interest discussed in this report) and $6.8 million for transportation-specific topics. Using benefit/cost (B/C) ratios that have been measured for other, past high-profile transportation research initiatives, a 5-to-1 to 20-to-1 B/C ratio for the CTES initiative would be realistic, highlighting the strategic importance of pursuing the research plan.

FIGURE 7-4 CTES strategic research roadmap framework.
SOURCE: Quiroga, 2015.

Enhanced efforts and support of the following research programs and strategies will improve preparedness of the state's transportation systems for oil and gas development and production:

- **improved availability and quality of data related to ongoing and forecasted drilling activities;**
- **development of integrated, multimodal transportation infrastructure strategies and solutions; and**
- **provisions for reliable, sustainable funding for proactively preparing the state's transportation infrastructure for future drilling activities.**

SUMMARY

Development of the abundant shale resources across Texas via hydraulic fracturing and multi-stage, horizontal drilling has entailed increases in the volumes of equipment and personnel at well sites across the state. Not only have there been considerable increases in truck traffic across the state, other modes of transportation have also experienced a surge in traffic, as evidenced by the significant increase in energy-related activities at transportation facilities such as ports, railroads, and pipelines.

These increased traffic volumes have accelerated the degradation of pavements and roadside infrastructure. The accelerated damage of pavement structures along secondary state highways and local roads has been estimated at $1.5 to $2.0 billion per year. Costs to the trucking industry are also significant. A preliminary evaluation of the cost in the form of additional vehicle damage and lower operating speeds estimated the cost at $1.5 to $3.5 billion per year.

There also have been increases in accidents associated with the increased traffic volumes. Changes in crash rates have been more pronounced for crashes involving trucks and, particularly, for rural crashes that involve trucks. In most cases, as the severity of the injuries resulting from these crashes worsens, the changes in the corresponding number of crashes have been more pronounced. The result has been a higher percentage in the number of fatal, incapacitating, and non-incapacitating injury crashes in energy development regions compared to overall changes for all types of crashes.

The Texas Legislature has allocated funds to address some of the state's most critical transportation system and safety needs. In some cases, counties and local jurisdictions have also been able to make use of a limited amount of funds based on increased tax revenues to address urgent transportation system challenges. For the most part, however, unmet needs far exceed the availability of the existing funds.

Findings

- **Current technologies for oil and gas development and production from shale formations require very large numbers of heavy truckloads.**

- **Most existing roadway and bridge infrastructure in Texas was not designed to carry or accommodate the current large numbers and weights of truckloads.**
- **Traffic increases—especially truck traffic—associated with the development and production of oil and gas from shale formations in Texas have resulted in increases in the frequency and severity of traffic crash incidents.**
- **The level of funding to address the impacts to the transportation infrastructure and traffic safety in the oil and gas industry area is low relative to the magnitude of the impact.**

Recommendations

- **Enhanced efforts and support of the following research programs and strategies will improve preparedness of the state's transportation systems for oil and gas development and production:**
    - **improved availability and quality of data related to ongoing and forecasted drilling activities;**
    - **development of integrated, multimodal transportation infrastructure strategies and solutions; and**
    - **provisions for reliable, sustainable funding for proactively preparing the state's transportation infrastructure for future drilling activities.**

8

Economic and Social Impacts

- Shale energy development primarily contributes positively to local, regional, and state economies, but not all economic effects have been positive.
- Community leaders and residents in Texas tend to appreciate and welcome the economic and service-related benefits that accompany shale energy development, whereas they tend to dislike certain social and/or environmental effects that accompany it.
- The more negatively shale energy development is perceived—particularly with respect to the social and environmental consequences—the more likely local residents are to engage in behaviors opposing increased shale development.
- Decisions regarding setback distances in Texas are established at the municipal level.
- Shale development has the potential to disproportionately affect certain segments of the population.

This report has discussed many different implications and scientific research findings regarding the implications of shale energy resource development in Texas since the early- and mid-2000s. Rapid shale energy development has generated many debates and controversies surrounding both objective and perceived outcomes and impacts. In addition to potential impacts on the environmental systems and transportation systems described in this report's previous chapters, development of shale oil and gas resources in Texas has prompted concerns and questions regarding positive and negative effects of shale development on communities, public facilities such as schools, availability and affordability of housing, and possible health effects on individuals. Numerous studies in the United States and abroad, initiated by social and behavioral scientists and economists, are investigating socioeconomic pros and cons of shale energy development and hydraulic fracturing. As this chapter will explain, the body of work on socioeconomic implications of shale energy resource development in Texas is relatively recent and far less extensive and mature than work in most of the other subject matter areas in previous chapters.

This chapter summarizes findings from selected studies that have examined economic, social, and community-level issues associated with shale energy development in Texas. The character of the data, evidence, and research methods employed in social science and economic analyses often are very different than those used in the academic fields addressed in this report. In that sense, this summary complements the discussions, findings, and recommendations from other chapters and helps provide a more comprehensive and transdisciplinary perspective of the scientific knowledge base regarding implications of shale oil and gas development in Texas. This chapter is divided into discussions of economic and social issues pertaining to Texas shale energy development.

ECONOMIC IMPACTS

There has been considerable discussion in Texas about shale development's effects on business sectors that benefit from increases in community economic activity and population. The term "multiplier effect" is a macroeconomics concept that refers to how an increase in one economic activity may result in increases in other, related economic activities. The concept dates back many decades, with development of the modern concept of a multiplier effect attributed to the work of John Maynard Keynes and others in the 1930s. The concept has different applications, and often is applied in macroeconomics analysis, and in the banking sector (e.g., projecting possible changes in money supply). It often is used to project the possible effects of fiscal policy or other changes in spending.

Some analysts in Texas have considered this concept in evaluations of the economic effects of shale energy development. For example, The Perryman Group (2014), Tunstall et al. (2014), North Texans for Natural Gas (2014), and others (Ewing et al., 2014), have concluded that shale energy development contributes positively to local, regional, and state economies. However, a 2015 paper (Lee, 2015) noted that the true extent of those economic impacts, which were derived from conventional economic input-output studies, may be debatable due to the size of the estimated multiplier effects in the model. Regardless of whether the multiplier effects of shale energy development are actual or inflated, economic data reveal local, regional, and state-wide positive economic impacts.

Economic Impacts in the Permian Basin, Barnett Shale, and Eagle Ford Shale Regions

The oil and gas industry in the Permian Basin provides substantial economic benefits to Texas and New Mexico. Economic estimates for 2013 revealed that the Permian Basin's oil and gas industry sustained over 546,000 jobs, generated $137.8 billion in economic output, and contributed more than $71.1 billion to the gross state products of Texas and New Mexico (Ewing et al., 2014). The Texas portion of the Permian Basin-related oil and gas activity sustained over 444,000 jobs, generated $113.6 billion in economic output, and contributed over $60.2 billion to the state of Texas.

Energy exploration and development activities in Texas' shale plays have resulted in primarily positive effects on local, regional, and state economies. For many years, The Perryman Group, a Texas-based company specializing in financial and economic analysis, has evaluated the economic impact of energy development activities in the Barnett Shale. According to the most recent estimates (The Perryman Group, 2014), Barnett Shale-related activities in the year 2013 resulted in roughly $11.8 billion in gross product and more than 107,650 jobs within the Barnett Shale region. Tax receipts to local governments (i.e., cities, counties, and school districts) and the state of Texas were estimated at $480.6 million and $644.7 million, respectively. For the state as a whole, Barnett Shale-related activity was estimated to be $12.8 billion in gross product and supported approximately 115,000 jobs. Local governments collected roughly $517.3 million and the state collected $686.3 million from statewide activity.

Since 2001, the cumulative effects of Barnett Shale-related activities have been $110.7 billion in gross product and about 993,600 person-years of employment (The Perryman Group, 2014). Tax revenues within the region were estimated at roughly $4.5 billion for local governments and more than $6 billion for the state. With respect to Texas as a whole, Barnett Shale-related activity has generated an estimated $120.2 billion in gross product and over 1,062,700 person-years of employment since 2001 (ibid.). Tax receipts to local governments were estimated at $4.8 billion; tax receipts to the state were estimated at $6.4 billion.

According to The Perryman Group 2014 report, projected economic benefits of Barnett Shale-related activities for the region between 2014 and 2023 will include $141.5 billion in gross product and 1,268,161 person-years of employment, while tax benefits for local governments and the state will include $5.7 billion and $7.4 billion, respectively (ibid.). During that same time period, the contribution of these activities to the Texas economy is projected to be about $153.4 billion in gross product, 1,354,727 person-years of employment, and tax receipts of $6.1 billion to local governments and $8 billion to the state.

Some similar studies of economic impacts of oil and gas development have been conducted in the Eagle Ford shale region. One of these studies considered economic implications of energy production development in 2013 in 21 counties in that region directly and indirectly involved in energy production. Study findings included that oil and gas activity resulted in $87.8 billion in economic output to the 21-county area (Tunstall et al., 2014). The oil and gas industry employed over 150,000 people and provided roughly $2.2 billion to both local governments and the state. The study also offered a 2023 economic output projected estimate of roughly $155 billion in the region. It was estimated that the oil and gas industry will provide approximately 220,000 full-time equivalent jobs and supply over $4.7 billion to both local governments and the state (Tunstall et al., 2014).

In addition to these studies, a 2014 paper (Raimi and Newell, 2014) describes oil- and gas-related revenues and service demands that county and municipal governments have experienced in Texas and several other U.S. states with active shale energy development activities. In addition to Texas, the paper included information and case studies from Arkansas, Colorado, Louisiana, Montana, North Dakota, Pennsylvania, and Wyoming. Based on extensive interviews with officials in these states, along with analysis of financial data, the authors concluded that most county and municipal governments have experienced net financial benefits, although some areas appeared to have experienced net negative fiscal impacts (Raimi and Newell, 2014).

Shale energy development primarily contributes positively to local, regional, and state economies, but not all economic effects have been positive.

Economic Impacts within Local Counties and Communities

Limited published data exist on the net benefits of shale energy development to local communities and their institutions and residents. A 2012 study of Colorado, Wyoming, and Texas examined the effects of natural gas production from 1998/99 to 2007/08 on county-level rates of total employment, total wage and salary income, median household income, and poverty (Weber, 2012). This analysis revealed that the average value of natural gas production increased by $757 million in energy counties experiencing an upturn where increase in gas production between 1998/99 and 2007/08 was in the top 20 percent. Every $1 million in additional gas production added 2.35 jobs and generated roughly $91,000 in wage and salary earnings in the average county experiencing an upturn. By contrast, the analysis found no statistically-significant effects on county-level poverty rates (Weber, 2012).

A 2013 review of the economic impacts of shale gas development on Texas state and local economies found:

> there are many uncertainties regarding the net benefits of shale gas development on state and local economics. There are sufficient independent research findings on extractive industry impacts to question the claims commonly propounded by the

> industry, and repeated by the press, that shale gas extraction will bring prosperity to local communities.
>
> (Barth, 2013, p. 96)

As part of the Barth (2013) study, data on unemployment rates, growth in median household income, and number of people in poverty in the four core gas-drilling counties in the Barnett Shale—Denton, Johnson, Tarrant, and Wise—were compared to the rest of Texas. Based on data obtained from the U.S. Census Bureau, Small Area Estimates Branch, and the Bureau of Labor Statistics, the study noted that for the 2003 to 2010 period, median household income increased by 21.2 percent in Texas, but only between 10 and 16 percent in the four core Barnett Shale counties (Barth, 2013). Increases in the unemployment rates in the four Barnett counties were higher than the state average of 1.5 percentage points, ranging between 1.8 to 2.4 percentage points between 2003 and 2010. Finally, the increase in the number of people in poverty in the four-county area mirrored the increase at the state level. Given the apparently incomplete and contradictory information found in this 2013 study, additional research on the economic impacts of shale energy development in Texas may be warranted.

A 2015 investigation explored the economic impact of oil and gas exploration and production in a 14-county area in the Eagle Ford Shale region in South Texas (Tunstall, 2015). This study used data from a four-year time period (2008 to 2011) to examine the correlation of the number of completed county-level wells with per-capita income changes. The study states that the number of completed wells represented "a direct indicator of the economic activity associated with oil and gas production" (Tunstall 2015, p. 87) and per-capita income offered "a straightforward measure of economic progress" (Tunstall 2015, p. 86). The data indicated mixed support that the number of completed wells in the 14-county area in the Eagle Ford Shale between 2008 and 2011 was positively associated with per-capita income. Completed wells reached statistical significance in some of the models, and failed to reach significance in others. The study had some limits regarding sample size (56 total observations) and noted that more data and research are needed to better comprehend issues associated with local economic development during an energy resource upturn.

A 2016 study examined the relationship between the property tax base and housing values from 1997 to 2013 in 79 ZIP codes in the Dallas-Fort Worth region (Weber et al., 2016). Thirty-seven of the ZIP codes were located entirely within the Barnett Shale play and defined as shale ZIP codes; 42 were located outside of the Barnett Shale and defined as non-shale ZIP codes. The data revealed a correlation between the taxing of oil and gas wells as property and housing values, with housing values in shale ZIP codes appreciating more than those in non-shale ZIP codes. In 2013, shale ZIP codes retained a 9 percent advantage in housing values over non-shale ZIP codes.

The primary explanation for the appreciation in housing values given by the authors was the taxation of natural gas wells. Taxation of natural gas wells as property expands an area's total property tax base, potentially causing benefits to local residents, such as declines in tax rates or increases to school funding and public amenities. As speculated by the authors, "any one of these changes should make the locality a more attractive place to live and increase housing values" (Weber et al., 2016, p. 590). Support for their hypothesis was found, leading the authors to conclude that "without taxation of natural gas wells as property, drilling in the Barnett Shale would have had minimal effect on the property tax base and a potentially negative effect on housing values" (Weber et al., 2016, p. 610).

Limited published data exist on the net economic benefits and costs of shale energy development to the institutions and residents in Texas counties and communities.

Economic Impacts on Public School Districts and Universities

A 2014 report examined the various ways in which oil and natural gas development benefited public schools and universities across Texas (North Texans for Natural Gas, 2014).

Key findings from the report included:

- oil and natural gas production generated over $1.5 billion in property tax revenue for Texas schools in FY2014;
- the Permanent School Fund—a state education endowment supporting K-12 public schools—received $676 million in FY2014 from oil and natural gas revenues;
- 595 independent school districts generated property tax revenues from mineral-producing properties;
- roughly 230 independent school districts are located in areas where oil and natural gas producing properties generated at least $1 million in property tax revenue in FY2014; and
- the Permanent University Fund—an endowment supporting the University of Texas and the Texas A&M University systems through oil and gas royalties on certain state-owned lands—was at the time valued at $21.8 billion.

To put these numbers in context, overall property tax revenue for the state of Texas in 2014 was $49.1 billion, which is 45.6 percent of total tax revenue. Appraisal districts reported the market value of taxable property in school districts statewide to be $2.5 trillion, with a taxable value of $2 trillion. The $1.5 billion in property tax generated from oil and gas represented 6.3 percent of statewide school district market value in 2014 and 7.8 percent of the taxable value (Hegar, 2016).

Public school districts and universities across Texas benefit substantially

from the taxes and royalty revenue paid by the oil and gas industry.

Economic benefits associated with oil and gas development are unevenly distributed across public schools and universities.

Additional research on the economic benefits and costs and associated equity issues—or "winners and losers"—in shale energy development is warranted. The broad implications of shale development for local governments and public school districts also should be investigated.

SOCIAL IMPACTS

Studies of sociological impacts from shale oil and gas development in Texas represent a contrast to bodies of knowledge and research in the areas discussed in this report's previous chapters. The following discussion and summary of these issues in Texas are based on the relatively small number of papers and research initiatives undertaken in the past 10 years. By way of comparison, studies of Texas geology and seismic activity date back over 100 years, and there are numerous volumes of work, major federal and state research projects, and state agencies established to study Texas geology and earthquakes. In many senses, and especially compared to fields such as geology and earthquakes, groundwater systems, and transportation, research on the sociology of Texas shale oil and gas is in its early stages. This makes it more difficult to draw broad conclusions and generalizations about community reactions to Texas shale energy development as well as to identify knowledge gaps that would help further the state of sociological knowledge.

A few centers and individuals have conducted a significant proportion of the economic and sociological analyses in Texas to date. The Perryman Group and its focus on financial and economic issues in Texas has been mentioned. The University of Texas at San Antonio and its Institute for Economic Development has led many prominent study initiatives that have explored the economic implications of shale oil and gas development across the state. Finally, some studies conducted at Sam Houston State University have focused on social impacts, perception, and opinions regarding shale energy development. Given the relative novelty of work on these topics in Texas, research conducted by these entities and individuals and their collaborators makes up a significant portion of the entire body of knowledge gathered and assessed to date.

The following sections address regional public perceptions and adaptations to shale oil and gas development including the issue of setback distances. Research on the topic of social and environmental justice then is addressed, with a final section describing observations on engaging the local community in the energy development.

Perceptions of Shale Energy Development—Barnett Shale and Eagle Ford Shale

One of the early sociological studies on shale energy development was conducted in the Barnett Shale in March 2006 (Anderson and Theodori, 2009; Theodori, 2009). This work was based on data collected from 24 local leaders in two Barnett Shale counties—Johnson County and Wise County—to investigate their positive and negative perceptions of shale development. Specifically, the research aimed to obtain answers to the following questions:

- What local-level benefits have occurred because of increased energy development?
- What negative impacts have accompanied increased development?
- Have the benefits of development outweighed the costs?

The data revealed that leaders in both counties unanimously agreed that energy development had stimulated economic prosperity for their communities. According to the respondents, benefits included increased city revenues, property values, and household incomes. Respondents also noted improvements in the retail sector (i.e., the presence of new business and increased shopping choices) and to schools and medical facilities. Overall, leaders in both counties recognized the economic contributions of the energy industry at the local level.

Meanwhile, the leaders identified several negative effects related to these developments that were classified into three categories of concern: 1) threats to public health and safety; 2) environmental concerns; and 3) quality-of-life issues (Anderson and Theodori, 2009). Potential threats to public health and safety included increased truck traffic and accidents on roads, possible gas leaks and explosions, and the placement and sheer number of disposal wells throughout the counties. Environmental concerns included possibilities of increased air pollution, contamination of freshwater supplies, and the amount of freshwater used in the hydraulic fracturing process. Quality of life concerns included a vast array of inconveniences related to the drilling phase (e.g., lights, noises, etc.), changes to the aesthetic value of the landscape, deteriorating conditions of streets and roads, and issues between the "haves" and "have nots" (with respect to mineral rights ownership) in the local communities.

Building upon the preceding study of local leaders, a 2006 study based on a random sample of residents in the same two counties—Johnson and Wise—examined their perceptions of 30 issues which may or may not have been perceived to be problematic (Theodori, 2009). Regardless if the respondent viewed the issue as problematic, he or she was asked to indicate whether the issue was "getting worse," "getting better," or "staying the same" with the continued development of shale gas.

After ranking the 30 issues in ascending order by overall mean score, 24 issues had negative mean values, indicating that respondents perceived the issue as getting worse with continued development of shale gas (Theodori, 2009). The issue of "increased truck traffic" had the highest negative mean value, followed by the "amount of freshwater used." Conversely, six economic and/or service-related concerns were perceived to be getting better with continued shale gas development, including poverty reduction, local police protection, medical and health care facilities, quality of local schools, fire protection services, and availability of good jobs. A general conclusion was:

> the results of this study reveal a paradox among the general population. On one hand, it appears the members of the general public typically dislike the potentially problematic social and/or environmental issues perceived to accompany natural gas development. However, on the other hand, local citizens generally appreciate and view favorably the economic and/or service-related benefits that normally accompany such development.
>
> (Theodori, 2009, p. 111)

Results of subsequent analyses using the data from the counties of Johnson and Wise (Theodori, 2012; Wynveen, 2011), and an additional general population study in Tarrant County (Theodori, 2013), echo this notion of paradoxical perceptions of shale energy development. In those Barnett Shale studies, the key finding pertaining to perception of the oil and natural gas industry is that members of the general public consistently view *more negatively* social and/or environmental issues perceived to accompany shale energy development and view *less negatively* the economic and/or service-related benefits that often result from such development.

Similar findings were uncovered in the Eagle Ford Shale (Ellis et al., 2016; Li et al., 2014; Theodori and Luloff, 2015). Preliminary results of a 2013 investigation of community impacts of shale development in four counties[12] in the Eagle Ford Shale region (Li et al., 2014) were similar to results from previous research in the Barnett Shale region. Social and environmental impacts such as increases in crime, water issues (i.e., water pollution, water use by the oil and gas industry, and depletion of aquifers), and traffic and road conditions were viewed as major concerns by local residents. Moreover, approximately one-half of survey respondents believed that those same social and environmental impacts had gotten worse due to shale development. Conversely, residents believed that economic issues such as the job market and average incomes had improved.

The Ellis et al. study used semi-structured interview data to investigate the objective and perceived community impacts of shale development in the Eagle Ford Shale region (Ellis et al., 2016). Qualitative data were obtained through interviews with 34 community leaders and nine industry officials in La Salle, McMullen, Karnes, and Gonzales counties and through focus group meetings with 46 local residents in La Salle and Karnes counties. The data analyses revealed several common themes with respect to the identified community impacts associated with

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[12] The four counties were Bee, Karnes, LaSalle, and McMullen.

shale development. Similar to the research conducted in the Barnett Shale roughly 10 years earlier (Theodori, 2009), local leaders and residents were found to be very concerned about the social and/or environmental impacts of energy development in and around their communities (Ellis et al., 2016). Although generally enthusiastic about new and long-term economic benefits to the region, interviewees and focus group participants described increased truck traffic, increased cost of living expenses (e.g., rents, food, and fuel prices), and increased environmental and health risks (e.g., flaring issues and water contamination) as salient negative outcomes of development.

Community leaders and residents in Texas tend to appreciate and welcome the economic and service-related benefits that accompany shale energy development, whereas they tend to dislike certain social and/or environmental effects that accompany it.

In-depth examination of data obtained from the interviewed community leaders—especially those leaders in elected positions—revealed they continuously confronted a tension between encouraging and supporting energy development-related economic growth and managing the associated negative social and environmental outcomes. Three key factors reportedly hindered leaders' efforts to effectively protect residents from the negative social and environmental consequences of development. First, rural governments lacked the capacity to effectively monitor and respond to emerging risks. Second, the rural geography presented logistical and social obstacles for collaboration among local governments. And third, the predominant political culture of the region often limited the willingness of local leaders to explore and advocate for increased regulatory measures.

Immediately following data collection in the Ellis et al. study, random samples of residents and absentee landowners in Karnes and La Salle counties were contacted during March through May 2015 and were asked to participate in a survey of public perceptions of oil and natural gas development in the Eagle Ford Shale region (Theodori and Luloff, 2015). Survey participants were asked about:

- the oil and gas industry;
- potentially problematic issues associated with oil and gas development;
- their trust in selected groups/organizations as sources of information about positive and negative impacts of oil and/or natural gas development;
- their satisfaction with oil and natural gas industry performance;
- their satisfaction with communications about oil and gas industry activities;
- community leaders' decisions related to nearby oil and gas development;
- efforts by federal and state agencies and regional and local groups/organizations to include local residents' input into decisions related to oil and gas industry development; and
- management, disposal, and reuse of flowback waters from shale oil and gas wells.

Key findings included:

- Residents and absentee landowners in the Eagle Ford Shale viewed the perceived social and/or environmental effects of large-scale energy development more negatively than the perceived economic and/or service-related benefits of such development. This finding parallels results from earlier research in the Barnett Shale (Theodori, 2012, 2013).
- Certain impacts perceived to be slight-to-moderate problems in the Eagle Ford Shale region prior to the shale upturn were viewed as getting worse due to the large-scale development. The worsening issues were predominantly traffic-related, including both traffic accidents and traffic congestion. In particular, increased truck traffic has been found to be of critical concern to residents in and around communities with extensive energy production activities in Texas (Anderson and Theodori, 2009; Quiroga and Tsapakis, 2015; Theodori, 2009). Conversely, previously problematic issues, such as availability of good jobs and the outmigration of young people from the community after high school, were perceived to be getting better with the large-scale development of oil and natural gas in the region. Again, many of these findings mirror those of earlier studies in other Texas shale plays (Theodori, 2009).
- Residents and absentee landowners in the Eagle Ford Shale were least trusting of the county and city governments as reliable sources of information about positive and negative impacts of oil and/or natural gas development, and were least satisfied with communication of information about such development in and near their community. Residents and absentee landowners were also least satisfied with the efforts of county and city governments to incorporate concerns of local residents in decisions regarding oil and gas development. Both groups rated elected officials (both at the county and city levels) and local religious leaders among their least-trusted sources of information to deliver unbiased, factual information on hydraulic fracturing.
- Residents and absentee landowners in the Eagle Ford Shale were more trusting of the Texas A&M AgriLife Extension Service13, scientists and researchers, and the oil and natural gas industry as trustworthy sources of information about positive and negative impacts of shale oil and/or natural gas development. The Theodori and Luloff 2015 study showed that they were more satisfied with oil

[13] For more information on the Texas A&M AgriLife Extension program, see http://agrilifeextension.tamu.edu/.

and gas industry officials as conduits of communication involving oil and gas activities than they were with their county and government officials. Further, residents and absentee landowners were also more satisfied with the efforts of Agrilife Extension, scientists and researchers, and the oil and natural gas industry to include local residents' concerns into decisions regarding oil and gas development. Moreover, AgriLife Extension and the oil and natural gas industry ranked in the top five most-trusted sources of information to deliver unbiased, factual information on hydraulic fracturing (second and fifth, respectively).

- Survey respondents believed residents and local officials should have the most influence on management decisions, yet they believed citizens and leaders actually have the least amount of influence. In contrast, respondents believed state and federal groups/organizations—the Texas Legislature, the U.S. Congress, and federal and state natural resources agencies—actually have the most influence on management decisions, yet they believed such groups/organizations should have lesser influence.
- Residents and absentee landowners generally were satisfied with the performance of the oil and natural gas industry in the Eagle Ford Shale. Survey respondents were more satisfied with the extent to which industry communication practices are adaptable to local emergencies and the extent to which crises are handled appropriately through communication by the industry. They were less satisfied with the clarity and conciseness of industry communication of less urgent information and the extent to which they believed industry anticipates local community residents' need for information.
- Lastly, the investigation of beliefs that treated flowback water could safely be used for eight potential purposes indicated that the overall pattern of results paralleled those uncovered from the general public in the Marcellus Shale region (Theodori et al., 2014). The findings from the Eagle Ford as well as those from the Marcellus Shale region, demonstrate that acceptance of/opposition to the use of treated flowback wastewater varies directly with intimacy or degree of human ingestion.

Traffic-related issues—including increased truck traffic, traffic accidents, and traffic congestion—are of primary concern to leaders and residents in and around communities experiencing shale development.

Drawing upon the public perceptions of oil and natural gas development in the Eagle Ford Shale region survey data, researchers examined 1) individuals' self-reported familiarity with the process of hydraulic fracturing and compared the levels of familiarity to those reported in a study of Marcellus Shale residents (Theodori et al., 2014); and 2) the associations between the contributions of 15 informational sources to self-reported knowledge about hydraulic fracturing and self-reported levels of familiarity with the process itself (Theodori and Ellis, 2017).

Study results revealed that survey respondents in the Eagle Ford Shale region of Texas perceive themselves to be slightly more familiar with the process of hydraulic fracturing than those living in the Marcellus Shale region of Pennsylvania. Forty percent of respondents in the Marcellus Shale study indicated having some level of familiarity with hydraulic fracturing (scores of 5 through 7 on a 7-point familiarity scale), whereas roughly 61 percent of respondents in the Eagle Ford Shale study reported some level of familiarity with the process. Moreover, the study results indicated that the informational source that contributed most to respondents' self-reported familiarity with hydraulic fracturing was the oil and natural gas industry. Regulatory agencies, conservation and environmental groups, and internet websites were also contributors to respondents' familiarity of hydraulic fracturing, but the strength of these relationships was somewhat weaker.

The oil and gas industry is viewed as a relatively trustworthy source for information on shale development and hydraulic fracturing.

Additional research on the underlying factors accompanying the formation of both positive and negative perceptions of shale development is needed.

Box 8-1 discusses Matagorda County resident perceptions regarding energy development (with some emphasis on low-temperature geothermal energy).

BOX 8-1
Public Perceptions and the Framing of Information

The Matagorda County, Texas study also looked at the issue of public perceptions regarding different forms of energy (Higgins, 2016). Results indicated that respondents had predominantly positive views about solar, wind, nuclear, and oil and gas energy, and negative views regarding coal. The majority of respondents were initially uncertain about low-temperature geothermal energy. Further analysis revealed that framing information about low-temperature geothermal energy in a manner congruent with the values and environmental orientations of respondents affected their perceptions of the development of this type of energy.

The study concluded that, to maximize the likelihood of success of energy development initiatives—whether low-temperature geothermal energy or other forms—it is critical to communicate with and actively involve local residents from the earliest stages of planning, and to communicate with the public early and in a manner that is consistent with their values and environmental perspectives. Consistent with findings from previously reviewed literature on the Barnett and Eagle Ford Shale developments, timely engagement and transparent communication with the public on the potential

> social and environmental impacts may have been lacking. Little communication and limited involvement of interested parties may be associated with the paradoxical perceptions of shale development reported in previous studies (e.g., Theodori, 2009).

Behavioral Responses to Shale Energy Development—Barnett Shale

Despite the growing number of attitudinal studies on shale energy development, little empirical social scientific work in Texas has examined behavioral variables (i.e., variables measuring behaviors or behavioral intentions) in response to shale development. A 2009 study built upon previously conducted attitudinal research in the Barnett Shale, using data collected in a general population survey from a random sample of individuals in Tarrant County, Texas (Theodori, 2013). This effort examined public perception of the natural gas industry and its effects on six behavior-related dependent variables—three variables reflecting past behaviors and three variables indicative of behavioral intent. Consistent with findings from previous attitudinal studies (Anderson and Theodori, 2009; Theodori, 2009, 2012; Wynveen, 2011), the results indicated that while residents of Tarrant County disliked certain potentially problematic social and environmental impacts perceived to accompany natural gas development, they viewed more positively the economic and/or service-related benefits that often result from such development (Theodori, 2013).

Moreover, the analyses revealed that the social and environmental element was a key factor both in explaining past individual civic actions taken in response to the development of natural gas and in predicting future behaviors likely to be taken in response to proposed developments. For example, the study revealed that individuals with more negative views on the social and environmental factor *were more likely* than their counterparts to have: 1) contacted a local elected official or governmental agency to complain about a natural gas drilling and/or production issue; and 2) voted against a political candidate with a favorable position on the drilling and/or production of natural gas. Similarly, results indicated that individuals with increasingly negative views on the social and environmental factor reported that they *would be more likely* than their counterparts to: 1) contact a local elected official or governmental agency to complain about a natural gas drilling and/or production issue; and 2) vote against a political candidate because of his/her favorable position on the drilling and/or production of natural gas. An important finding of this paper was that:

> … representatives of the energy industry, community leaders, governmental and regulatory agency personnel, non-governmental and environmental organization representatives, and other stakeholders must recognize and understand that the public's perception of shale gas development—what the public thinks about such development, particularly with respect to the social and environmental consequences—is associated with *both very real and very meaningful* actions. (Theodori, 2013, p. 131)

The more negatively shale energy development is perceived—particularly with respect to the social and environmental consequences—the more likely local residents are to engage in behaviors opposing increased shale development.

Additional research is warranted to provide a more comprehensive understanding of the various factors that may be associated with behavior taken in response to or anticipation of shale development.

Setback Distances

The concept of setback distance refers to a regulatory distance from which a structure or development is "set back" from a street, road, river, floodplain, or any other place deemed to need protection. The concept can become controversial and contested if, for example, developers feel that the regulatory distances are too large, or in contrast, preservation and conservation groups and homeowners may feel that the distance is too small. It is easy to imagine how this issue can come into play in shale energy development when decisions are being made and permits are being issued for new well sites. In Texas, this concept has been studied in Denton County, where a 2013 paper reviewed drilling ordinance documents from 26 municipalities in Denton County (Fry, 2013). The paper analyzed the purpose and basis for determining setback distances. It found no uniform setback distance among municipalities in Denton County and concluded that setback distances are rooted in political compromises, as opposed to empirical or data-driven decisions. Setback distances "demarcate a highly politicized and negotiated space," which is generally the result of "political negotiations among council members, municipal lawyers, staff, citizens, mineral owners, and drilling companies" (Fry, 2013: 86, 87). Those political negotiations are rooted in "competing discourses," including "job creation and economic gain on the one hand, versus negative environmental and health effects on the other" (Fry, 2013: 87), which may help explain the paradoxical perceptions of shale energy development (Theodori, 2009).

Decisions regarding setback distances in Texas are established at the municipal level.

Additional research is needed to examine the potential environmental and health effects associated with varying setback distances.

Social and Environmental Justice

Additional studies conducted in Denton County looked at the concept of "environmental justice," which refers generally to evaluations of how planning decisions or past investments might disproportionately affect certain population subgroups. A 2015 analysis in Denton County applied an environmental justice framework to analyze the distribution of costs and benefits associated with shale gas development in Denton, Texas (Fry et al., 2015). That study examined data on mineral property values for 2002 to 2013 collected from the Denton Central Appraisal District, gas well location data from the Railroad Commission of Texas, and appraised mineral property values (used as a proxy for shale gas development royalty payments).

The paper found an uneven distribution of benefits and costs associated with development, and noted that, although *non-local* mineral owners are primary beneficiaries of shale gas development in Denton, "Denton's non-mineral owning residents receive no direct financial benefits, and very few indirect benefits, and are exposed to all the burdens and potential health risks because of their proximity to gas wells" (Fry et al., 2015: 106). This study touches upon issues regarding the separation between ownership of surface land and ownership of subsurface minerals and highlights the importance of setback distance regulations (Chapter 4 elaborated on issues regarding surface land ownership and mineral rights in Texas).

Another paper applied an environmental justice framework using data on the locations of disposal wells permitted between 2007 and 2014 in the Eagle Ford Shale region to analyze the racial, ethnic, and economic compositions of residents living near injection wells (Johnston et al., 2016). Their data indicated that injection wells were disproportionately permitted near communities with large percentages of minorities and high levels of poverty. According to the authors, "a pattern of environmental injustice extends to the Eagle Ford Shale region with respect to oil and gas wastewater disposal" (p. 553). The study suggested that "…discrepancies in locations of new wastewater disposal wells may be driven by and contribute to differences in political capital between people of color and white communities and between high- and low-wealth areas" (p. 554).

The above cross-sectional studies represent initial forays into the complex topics of social and environmental justice. Additional research replicating such analyses would be warranted before any substantive conclusions pertaining to the distribution of benefits and costs and the potential associations between the siting of wastewater disposal wells and the racial and socioeconomic characteristics of communities can be drawn.

Shale development has the potential to disproportionately affect certain segments of the population.

Additional research on the uneven distribution of benefits and costs associated with development is warranted.

Relevant Studies from Other States

Studies of the topics that have been discussed in this chapter have been conducted in other U.S. states (see Appendix B). Some of that work has been referenced in this chapter. In addition, some of those studies have identified topics that might be profitably studied in greater detail in Texas. Examples of knowledge gaps in the understanding of risks to communities from shale development include:

- intergenerational transfer of wealth and the community capture of wealth;
- relationships between health outcomes and social-psychological disruption;
- effects of stigma and conflict on long-term community investment and sustainability; and
- better knowledge of the long-term development picture for the shale gas industry to aid communities in planning beyond the immediate upturns and downturns (Jacquet, 2014).

Further studies of economic impacts of shale development could be of particular interest and value in Texas and elsewhere. For example, unlike previous downturns related to reductions in extractive activities as minerals became more profitable elsewhere, current activity in the Permian Basin area demonstrates that technologies developed for shale development enable and will enable additional similar development in the near future across the United States. There could be considerable merit in further studies of how to increase benefits and reduce adverse impacts from shale development.

SUMMARY

A small number of relatively recent studies have examined the objective and perceived economic and social impacts of shale oil and gas development in Texas. Clearly, there are numerous knowledge gaps in the economic and social science literatures on shale development.

Findings

This chapter has summarized findings from selected studies that have examined economic and social impacts associated with shale energy development in Texas.

- **Shale energy development primarily contributes positively to local, regional, and state economies, but not all economic effects have been positive.**
- **Limited published data exist on the net economic benefits and costs of shale energy development to the institutions and residents in Texas counties and communities.**
- **Public school districts and universities across Texas benefit substantially from the taxes and royalty revenue paid by the oil and gas industry.**
- **Economic benefits associated with oil and gas development are unevenly distributed across public schools and universities.**
- **Community leaders and residents in Texas tend to appreciate and welcome the economic and service-related benefits that accompany shale**

energy development, whereas they tend to dislike certain social and/or environmental effects that accompany it.

- **Traffic-related issues—including increased truck traffic, traffic accidents, and traffic congestion—are of primary concern to leaders and residents in and around communities experiencing shale development.**
- **The oil and gas industry is viewed as a relatively trustworthy source for information on shale development and hydraulic fracturing.**
- **The more negatively shale energy development is perceived—particularly with respect to the social and environmental consequences—the more likely local residents are to engage in behaviors opposing increased shale development.**
- **Decisions regarding setback distances in Texas are established at the municipal level.**
- **Shale development has the potential to disproportionately affect certain segments of the population.**

Recommendations

The following items represent areas where knowledge of potential economic and social implications of shale development is extremely limited, and should be considered as future research priorities.

- **Additional research on the economic benefits and costs and associated equity issues—or "winners and losers"—in shale energy development is warranted. The broad implications of shale development for local governments and public school districts also should be investigated.**
- **Additional research on the underlying factors accompanying the formation of both positive and negative perceptions of shale development is needed.**
- **Additional research is warranted to provide a more comprehensive understanding of the various factors that may be associated with behavior taken in response to or anticipation of shale development.**
- **Additional research is needed to examine the potential environmental and health effects associated with varying setback distances.**
- **Additional research on the uneven distribution of benefits and costs associated with development is warranted.**

9

Transdisciplinary Connections, Trade-offs, and Decision Making

- Significant connections that lack formal studies exist among the six topic areas discussed in this report. These connections include combinations of geological, economic, legal, and other topic areas.
- Disciplinary interconnections often are at the center of major trade-off decisions regarding shale development investments; however, they are difficult to clearly identify and evaluate.
- Connections among the multiple disciplinary areas and trade-off decisions that underpin shale investment decisions should be systematically identified, discussed, and evaluated.

This project and report from The Academy of Medicine, Engineering and Science of Texas (TAMEST) was convened to provide a credible and independent review regarding scientific knowledge that underpins shale development in Texas, and scientific gaps that could be filled through research and analyses. The task force review included current science knowledge and processes about which there is widespread agreement in many areas and longer-term processes and effects about which knowledge and understanding are less certain. The preceding chapters summarize the current state of research and knowledge in six key topic areas: geology and seismicity, land and ecosystem resources, air quality, water quantity and quality, transportation, and economic and social science research. As reflected in these chapters, most studies regarding Texas shale oil and gas development typically have focused on, and have been written from, the perspective of a single discipline. Each of these chapters noted some important relations and connections that exist among and across the topic areas of this report.

A unique and valuable aspect of this report is that task force study team members represented a wide spectrum of science, engineering, and social science disciplines. This report called for a review of existing research in six topic areas. In the course of the task force's internal deliberations, and its discussions with guest speakers, it became clear that few studies have sought to integrate concepts across different science fields. Exceptions would include studies of water and ecosystem dynamics, water management and landscapes, land and wildlife resources, or how changes in transportation patterns affect air quality. Even fewer studies or initiatives attempt to bridge biophysical sciences, social sciences, and policy research.

Evaluation of interrelationships and feedbacks between and across these disciplinary areas is difficult, expensive, and generally is not part of most traditional fields of study or university curricula. Nevertheless, these connections are pervasive and hence became a significant focus of task force discussion. The importance of these connections to comprehensive understanding and decisions regarding shale oil and gas development tends to be underappreciated, and is not systematically integrated into investment decisions.

Significant connections that lack formal studies exist among the six topic areas discussed in this report.

The nature of more integrative studies and initiatives in the future regarding Texas shale development requires careful consideration because of inherent complexity. There is no established blueprint or template for such studies and initiatives. Figure 9-1 presents a schematic example that could be used to encourage discussion regarding cross-disciplinary linkages and possible research initiatives. Such initiatives will require innovation and ingenuity to ensure that research is not only scientifically rigorous, but that findings offer useful, practical information for decision makers, analysts, the oil and gas industry, environmental groups, citizens, and other interested parties.

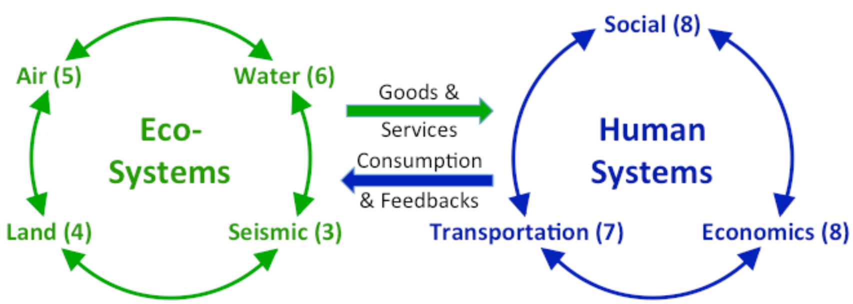

FIGURE 9-1 Interactions among elements of social-ecological systems affected by shale development. The number next to each element relate to the chapter in which each of the six topic areas in the TAMEST Shale Task Force report is addressed.

Traditional fields of inquiry, along with prospects for research funding and incentives for promotions and awards, generally emphasize and encourage discipline-specific studies. A more comprehensive understanding and evaluation of shale development implications in Texas, and elsewhere, would benefit from studies that integrate physical, ecological, and social sciences fields, and how they inform and influence one another.

Each of the six topic areas discussed in this report use distinct sets of data for analysis, and employ their own specific analytical and evaluation methods. The unique vocabulary from any given discipline may create barriers to discussions across disciplines, suggesting a need for better integration of terminology for more comprehensive understanding. Some commonality and overlap across disciplines in terminology does exist; for example, many similar chemical processes and methods are relevant to studies of air quality, water quality, and ecosystem function. Nevertheless, methods in the six topic areas addressed in this report cover a wide spectrum of approaches—including conceptual modeling, quantitative data and analyses, and qualitative, archival, and anecdotal research—and these varied approaches often make it difficult to formulate integrated conclusions.

A common shortcoming expressed in several chapters is the need for access to data and information acquired by various academic, governmental, and industrial entities. This issue is even more apparent for interdisciplinary research efforts.

TRADE-OFF DECISIONS AND INTERDISCIPLINARY STUDIES

Interconnections across disciplines influence many trade-offs and the pros and cons that are part of many shale development decisions. These reflect risk management practices, regulatory approaches, and community concerns regarding shale oil and gas development faced by decision makers, communities, and citizens across the state. For example, the process of horizontal drilling has advanced to a point where operators can reduce the number of wells needed to tap oil and gas resources. This reduces the surface impact of well pad construction. This also, however, entails concentrating water use at the point of a drill pad, which potentially stresses local water supplies and impacts roads used to transport fluids by trucks to and from the site.

Similarly, construction of additional pipeline infrastructure could reduce truck traffic and related road impacts and emissions. At the same time, this could fragment ecosystems and land resources on properties that pipelines traverse (although this impact might be reduced by elevating or burying pipelines, or by rapid land restoration and mitigation activities). Further, shale development often produces better paying jobs and a stronger tax base in a given community, but enhanced industrial activity has negatively affected affordability of housing, air quality, roads, and schools. Considering such trade-off issues and choices early in the development process with a group representing a broad range of interests and expertise could improve investment decisions.

Disciplinary interconnections often are at the center of major trade-off decisions regarding shale development investments; however, they are difficult to clearly identify and evaluate.

Multidisciplinary challenges and decisions posed by shale development could benefit from more specific "integrative" research ventures. Such research is not conducted frequently or comprehensively for many reasons:

- No single expert is likely to possess extensive knowledge of engineering, geological, physical, biological, social, economic and policy science fields, and research methods.
- Integrative studies entail active collaboration among groups of experts. The creation of research teams is a more resource- and time-intensive activity than studies conducted by smaller numbers of investigators from the same field of study.
- Integrative research initiatives face the conceptual, methodological, and analytical challenges (and perhaps even administrative challenges) of working across substantially different disciplines, each with its own set of paradigms, assumptions, terminology, rules, and norms.
- Such research generally entails longer evaluation time frames and larger spatial scales of analysis than generally is supported by traditional research grants and awards.

Additional knowledge regarding transdisciplinary effects of shale development likely will require research initiatives with innovative and creative funding arrangements, such as public-private research funding partnerships, and support from foundations with interests in shale oil and gas development. Indeed, these funding arrangements incentivize more sponsors to be involved, thereby widening the pool of interested parties.

Given limited transdisciplinary research regarding Texas shale oil and gas, the integrative knowledge generated by future cross-disciplinary studies would provide relevant and useful information for decision makers, citizens, and others regarding policies, actions, and long-term investments in shale development. Studies of integrated and interdisciplinary connections could support better shale development-related decisions, investments, and comprehensive understanding of these topics and the associated trade-off decisions. They could improve plans to expand oil and gas exploration, potentially mitigating impacts and enhancing benefits for multiple parties.

In addition to future research, the task force encourages initiatives for stronger collaboration and conversation of potential benefits, costs, and uncertainties regarding shale development investment decisions. A sustained discussion forum, for example, which might include representatives from the oil and gas sector, state agencies, academics, nongovernmental organizations and other experts, could enable sustained collaborative dialogue regarding interdisciplinary issues, and a more prominent appreciation of those issues. At the national level, the National Academy of Sciences (NAS), with funding from the federal government, the private sector, and foundations has established a "roundtable" forum for discussion of a variety of science-based issues associated with shale oil and gas development. The activity is overseen by a volunteer, expert panel that includes representatives from academia, industry, federal agency sponsors, research centers, and nongovernmental organizations. A primary goal is to support open conversation and dialogue of ongoing activities and areas of study, and identify priority areas of future research and information (and not offering consensus recommendations directed toward specific agencies or industry). This type of structure could be useful in Texas, where experience in oil and gas development is comprehensive and diverse. It is mentioned here as one example of an initiative that could be undertaken and developed in Texas to promote more systematic discussion and examination of relevant and important transdisciplinary issues regarding shale development.

Connections among the multiple disciplinary areas and trade-off decisions that underpin shale investment decisions should be systematically identified, discussed, and evaluated.

DIFFERENCES IN TIME SCALES AND UNITS FOR EVALUATION AND INVESTMENT DECISIONS

An additional challenge concerning the use of scientific and economic information relates to how differences between information, statistics, and methods affect our understanding of the benefits, costs, and risks that surround shale development. More specifically, information regarding benefits of oil and gas development tends to be direct, immediate, accessible, and easily converted into dollars (i.e., monetizable).

Generally, costs tend to breakdown into those that can be quantified and others that cannot. For example, direct and immediate costs associated with shale oil and gas development and production are easily and regularly measured in dollar terms. These costs include materials, labor, and capital required for drilling, injecting, and extracting oil and gas resources. However, costs related to environmental and socioeconomic impacts tend to be diffuse and difficult to monetize. Some effects may be less immediate. Others may be difficult to characterize unambiguously or relate conclusively to a specific cause.

Similarly, some effects on socioeconomic conditions may temporally lag and accumulate; for example, effects of air pollution or water contamination on human health. Because of the time lags and uncertainties of impacts and values of cumulative, large-scale and long-term environmental and socioeconomic costs may be unrecognized, discounted, or even excluded (externalized) in benefit-cost analyses of oil and gas development and investment decisions. A 2015 study (Werner et al., 2015) summarizes studies from several U.S. states and Australia related to health impacts of shale development. It cites several studies from Texas, some of which discuss similar research and evaluation limitations raised in this chapter. These studies included impacts related to air quality, traffic, and noise and light pollution, and addressed public perceptions of development risks. Consistent with the limitations considered in this chapter, the paper highlighted the limit of methodologically-rigorous work examining cause and effect between shale development operations and human health impacts, and the need for such research.

This does not imply that these latter effects are always present or substantial; the more important point is that these effects often do not manifest themselves immediately and are difficult to measure. Time lags often exist between immediate benefits from oil and gas development and delayed and cumulative environmental and socioeconomic costs of such development. Furthermore, there are commonly many uncertainties about these longer-term environmental and socioeconomic costs of large-scale development initiatives. Accordingly, decision-making bias is more frequent, due to the more immediate positive monetary effects of shale oil and gas development relative to the less visible and longer-term manifestation of some negative consequences. Comprehensive understanding and thorough decisions regarding shale oil and gas development will consider such costs and uncertainties. These issues can be complex, and the nature and proper weighting of these costs, risks, and uncertainties constitutes considerable decision and policy-making challenges.

Environmental costs, impacts on ecosystem services, and time lag effects are not unique to shale oil and gas development. For example, with regard to water and river systems, benefits from sales of hydropower generated from water stored in a dam often are immediate, direct, and commonly expressed in dollars. Longer-term and possible negative effects on river morphology, sediment retention (rather than discharge to estuarine and deltaic ecosystems), water dynamics and quality, and fisheries are less immediate and difficult to monetize. Similarly, savanna and grassland afforestation programs often emphasize immediate benefits, but de-emphasize negative effects on ecosystems and local livelihoods of replacing grazing areas with forests, changing hydrological dynamics of watersheds, and altering soil conditions and carbon dynamics (Veldman et al., 2015).

This report does not recommend specific actions for mitigating differences in measurements of benefits and costs across subject matter areas, or to assess the overall value of benefits and costs of shale development. Rather, these points are made to focus attention on these differences across disciplines and the different forms and time scales of information. This report has noted that the fields of geology, land resources, air quality, water, transportation, and socioeconomics all have different methods and means for collecting information and evaluating such information. Appropriately weighting and balancing these methodological considerations has presented persistent challenges for natural resources decision makers across the United States.

The task force seized an opportunity to compile what can be learned from the experience of shale development in Texas. This experience extends over several years and already includes the impacts of both upturns and downturns. As such, it underscores the value in assembling information across disciplines and time. This project, however, was charged to review the existing science literature. Experience over time applies in this report mainly to the six disciplinary areas independently because interdisciplinary studies, addressing the six topic areas in this report, do not yet exist.

The task force was not aware of any major, prominent initiatives to develop integrated approaches for monitoring, analyzing, and monetizing transdisciplinary implications of Texas shale development.

SUMMARY

Most, if not all, future shale development decisions likely will be affected by more than one of the topic areas featured in this report. Although investigation of transdisciplinary linkages was not explicitly part of this project's scope of work, shale investment decisions will be influenced by connections and processes that cross many of the subject matter areas investigated in this report.

Sound shale investment and related decisions will consider not only the individual topics, but also the connections between them, how effects in one area may influence effects in the other areas, and the varying time scales of the relevant processes involved. Those decisions will be strengthened to the extent that they acknowledge and anticipate trade-offs among these areas and related constituent groups, and seek a balance between short-term and long-term benefits and costs of those decisions—including costs and risks that may be more difficult to express in monetary terms. Furthermore, such decisions will be better informed by results from research initiatives that explicitly examine the systemic and interdisciplinary links across biophysical and social sciences fields and phenomena.

Findings

- **Significant connections that lack formal studies exist among the six topic areas discussed in this report.**
- **A common shortcoming expressed in several chapters is the need for access to data and information acquired by various academic, governmental, and industrial entities. This issue is even more apparent**

for interdisciplinary research efforts.

- **Disciplinary interconnections often are at the center of major trade-off decisions regarding shale development investments; however, they are difficult to clearly identify and evaluate.**
- **The task force was not aware of any major, prominent initiatives to develop integrated approaches for monitoring, analyzing, and monetizing transdisciplinary implications of Texas shale development.**

Recommendation

- **Connections among the multiple disciplinary areas and trade-off decisions that underpin shale investment decisions should be systematically identified, discussed, and evaluated.**

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Appendix A

TAMEST Task Force October 5, 2016 Meeting Agenda

J.J. Pickle Research Campus
The University of Texas at Austin, Austin

OPENING SESSION

8:30–9:00 AM *Opening Remarks*
David Russell, TAMEST President
Vice Provost and Dean of Basic Research
The University of Texas Southwestern Medical Center

Christine Economides, Chair, TAMEST Shale Task Force
Professor and Hugh Roy and Lillie Cranz Cullen Distinguished University Chair, Cullen College of Engineering
University of Houston

9:00–9:10 AM *Sponsor Perspectives*
Marilu Hastings, Vice President, Sustainability Program
The Cynthia & George Mitchell Foundation

EXPERT PRESENTATIONS

9:10–9:35 AM *Geology and Seismicity*
Peter Hennings, Research Scientist, Bureau of Economic Geology
The University of Texas at Austin

9:35–10:00 AM *Land Resources*
Forrest Smith, Dan L. Duncan Endowed Director of South Texas Natives and Texas Native Seeds Projects, Caesar Kleberg Wildlife Research Institute
Texas A&M University–Kingsville

10:00–10:20 AM **BREAK**

10:20–10:45 AM *Water*
Cal Cooper, Director of Special Projects and Emerging Technology
Apache Corporation

10:45–11:10 AM *Air*
David Parrish, Senior Research Scientist, Cooperative Institute for Research in Environmental Sciences (CIRES)
University of Colorado

11:10–11:35 AM *Transportation*
Cesar Quiroga, Senior Research Engineer, Texas A&M Transportation Institute (TTI)
The Texas A&M University System

11:35 AM–12:00 PM *Social and Economics*
Thomas Tunstall, Senior Research Director, Institute for Economic Development
The University of Texas at San Antonio

12:00–1:15 PM **LUNCH**

TEXAS STATE AGENCIES

1:15–1:40 PM *Texas Water Development Board*
Kathleen Jackson, Board Member

1:40–2:05 PM *Railroad Commission of Texas*
Lori Wrotenbery, Director, Oil and Gas Division

2:05–2:30 PM *Texas General Land Office*
Robert Hatter, Deputy Director, Energy Resources

2:30–2:50 PM **BREAK**

OIL AND GAS TRADE ASSOCIATION

2:50–3:15 PM *Texas Oil & Gas Association*
Todd Staples, President

ENVIRONMENTAL NGO

3:15–3:40 PM *Environmental Defense Fund*
Nichole Saunders, Attorney, U.S. Climate and Energy Program

3:40–4:00 PM **BREAK**

PANEL DISCUSSION: COMMUNITY PERSPECTIVES

4:00–5:00 PM *PANEL MODERATOR*
Gene Theodori, Professor, Department of Sociology
Sam Houston State University

BARNETT SHALE REGION
Judge Roger Harmon, Johnson County, Cleburne

EAGLE FORD SHALE REGION
Cristi LaJeunesse, Executive Director, Kenedy Housing Authority
Jeanette Winn Moczygemba, Superintendent, Karnes City Independent School District

PERMIAN SHALE REGION
Judge Mike Bradford, Midland County, Midland

5:00–5:15 PM *Closing Remarks*
David Russell, TAMEST President

5:15 PM **ADJOURN**

Appendix B

Select Research Articles of Subjective Shale Development Issues from States Outside of Texas

TOPIC	REFERENCE
Public Perceptions	
United States/ Multiple Shale Plays	Boudet, Hilary, Christopher Clarke, Dylan Bugden, Edward Maibach, Connie Roser-Renoug, and Anthony Leiserowitz. 2014. "'Fracking' Controversy and Communication: Using National Survey Data to Understand Public Perceptions of Hydraulic Fracturing." *Energy Policy* 65:57-67.
	Clarke, Christopher E., Philip S. Hart, Jonathon P. Schuldt, Darrick T.N. Evensen, Hilary S. Boudet, Jeffrey B. Jacquet, and Richard C. Stedman. 2015. "Public Opinion on Energy Development: The Interplay of Issue Framing, Top-of-Mind Association, and Political Ideology." *Energy Policy* 81:131-140.
	Crowe, Jessica, Ryan Ceresola, and Tony Silva. 2015. "The Influence of Value Orientations, Personal Beliefs, and Knowledge about Resource Extraction on Local Leaders' Positions on Shale Development." *Rural Sociology* 80(4):397-430.

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	Evensen, Darrick and Rich Stedman. 2016. “Scale Matters: Variation in Perceptions of Shale Gas Development Across National, State, and Local Levels.” *Energy Research & Social Science* 20:14-21.
Illinois (New Albany)	Crowe, Jessica, Tony Silva, Ryan G. Ceresola, Amanda Buday, and Charles Leonard. 2015. “Differences in Public Perceptions and Leaders’ Perceptions on Hydraulic Fracturing and Shale Development.” *Sociological Perspectives* 58(3):441-463.
Louisiana (Haynesville)	Ladd, Anthony E. 2013. “Stakeholder Perceptions of Socioenvironmental Impacts from Unconventional Natural Gas Development and Hydraulic Fracturing in the Haynesville Shale.” *Journal of Rural Social Sciences* 28(2):56-89.
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Michigan	Kreuze, Amanda, Chelsea Schelly, and Emma Norman. 2016. “To Frack or Not to Frack: Perceptions of the Risks and Opportunities of High-Volume Hydraulic Fracturing in the United States” *Energy Research & Social Science* 20:45-54.

TOPIC	REFERENCE
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	Jacquet, Jeffrey. 2012. "Landowner Attitudes Toward Natural Gas and Wind Farm Development in Northern Pennsylvania." *Energy Policy* 50:677-688.
	Jacquet, Jeffrey and Richard C. Stedman. 2013. "Perceived Impacts from Wind Farm and Natural Gas Development in Northern Pennsylvania." *Rural Sociology* 78(4):450-472.
	Kriesky, J., B.D. Goldstein, K. Zell, and S. Beach. 2013. "Differing Opinions about Natural Gas Drilling in Two Adjacent Counties with Different Levels of Drilling Activity." *Energy Policy* 58:228-236.
	Schafft, Kai A., Yetkin Borlu, and Leland Glenna. 2013. "The Relationship between Marcellus Shale Gas Development in Pennsylvania and Local Perceptions of Risk and Opportunity." *Rural Sociology* 78(2):143-166.
	Stedman, Richard C., Jeffrey B. Jacquet, Matthew R. Filteau, Fern K. Willits, Kathryn J. Brasier, and Diane K. McLaughlin. 2012. "Marcellus Shale Gas Development and New Boomtown Research: Views of New York and Pennsylvania Residents." *Environmental Practice* 14(4):382-393.
	Willits, Fern K., A.E. Luloff, and Gene L. Theodori. 2013. "Changes in Residents' Views of Natural Gas Drilling in the Pennsylvania Marcellus Shale, 2009-2012." *Journal of Rural Social Sciences* 28(3):60-75.

TOPIC	REFERENCE
Local and Community Impacts	
Australia	Measham, Thomas G. and David A. Fleming. 2014. “Impacts of Unconventional Gas Development on Rural Community Decline.” *Journal of Rural Studies* 26:376-385.
Pennsylvania (Marcellus)	Schafft, Kai A., Leland L. Glenna, Brandn Green, and Yetkin Borlu. 2014. “Local Impacts of Unconventional Gas Development within Pennsylvania’s Marcellus Shale Region: Gauging Boomtown Development through the Perspectives of Educational Administrators.” *Society and Natural Resources* 27:389-404.
Risk and Risk Governance	Jacquet, Jeffrey B. 2014. “Review of Risks to Communities from Shale Energy Development.” *Environmental Science & Technology* 48:8321-8333.
	Small, Mitchell J., Paul C. Stern, Elizabeth Bomberg, Susan M. Christopherson, Bernard D. Goldstein, Andrei L. Israel, Robert B. Jackson, Alan Krupnick, Meagan S. Mauter, Jennifer Nash, D. Warner North, Sheila M. Olmstead, Aseem Prakash, Barry Rabe, Nathan Richardson, Susan Tierney, Thomas Webler, Gabrielle Wong-Parodi, and Barbara Zielinska. 2014. “Risks and Risk Governance in Unconventional Shale Gas Development.” *Environmental Science & Technology* 48:8289-8297.
Familiarity with/ Knowledge of Shale Energy Development and/or Hydraulic Fracturing	Stedman, Richard C., Darrick Evensen, Sarah O’Hara, and Mathew Humphrey. 2016. “Comparing the Relationship between Knowledge and Support for Hydraulic Fracturing between Residents of the United States and the United Kingdom.” *Energy Research & Social Science* 20:142-148.

TOPIC	REFERENCE
	Theodori, Gene L., Fern K. Willits, A.E. Luloff, and David B. Burnett. 2014. "Hydraulic Fracturing and the Management, Disposal, and Reuse of Frac Flowback Waters: Views from the Public in the Marcellus Shale." *Energy Research and Social Science* 2:66-74.
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