ERCOT WEST TEXAS LOAD STUDY

ESTIMATE THE ELECTRIC LOAD IMPACTS OF OIL AND GAS RELATED ACTIVITIES

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Chapter 1. Executive summary

The Electric Reliability Council of Texas, Inc. (ERCOT) commissioned the Bureau of Economic Geology at the University of Texas at Austin to complete the West Texas Oil and Gas Related Electric Load Growth Forecast for the Texas portion of the Permian Basin. Due to the inherent different time cycles of operations in oil and gas activities within tight oil plays compared to electric transmission infrastructure, it is crucial for ERCOT and its stakeholders to understand the long-term production outlook and operation activities footprint for an adequate transmission network in the area.

ERCOT requests two objectives for this study:

- First, establish a sustainable process in developing the load outlook of oil and gas activities in Permian. This study delivers a set of expected load forecasts and provides a repeatable process in facilitating ERCOT to update future load forecasts following the same methodology.

- Second, develop a knowledge base of the relation between electric load and oil/gas activities. This study includes a comprehensive discussion on the relation and methodology in establishing the load estimate from each identified activity from the upstream and midstream operations.

Findings contained in this study and report estimated load covering the period of the year 2012 to the year 2035, including the expected load forecast starting the year 2021 for the next 15 years, in the study area, which spans 18 counties in the Texas portion of the Permian Basin. This study offers three scenarios of load forecasts for the forecasted period, 2021 through 2035, to reflect the range of possibilities of market conditions and decarbonization trends. The yellow bounded area in Figure 1-1 describes the scope of the current study, mainly the counties in the state of Texas and the Far West weather zone of ERCOT.

Based on current operation practice, for the 18 counties included in West Texas, the total required electric load is around 3400 megawatts for 2020, including loads from upstream productions, saltwater disposal, midstream gathering, transportation, and processing. There are three scenarios considered: market condition (mainly oil prices) and electrification level in midstream in the study area. The forecasted load varies greatly based on the assumptions of these two factors above.

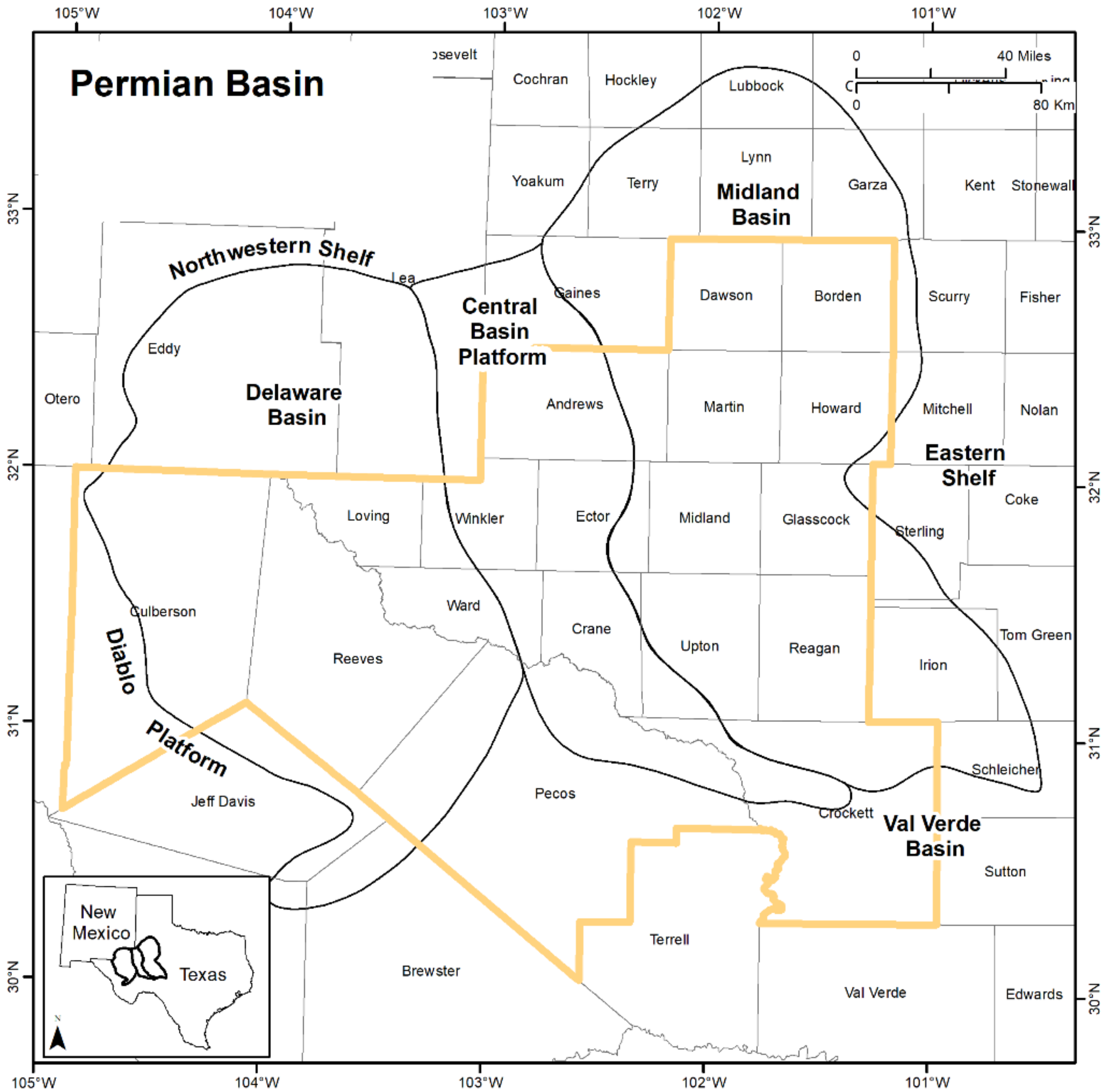

Figure 1-1 Counties included in the Permian Basin

To provide a robust view for the future, the load forecasts are presented in scenarios, based on key drivers relates to market condition, and operation trend in the field.

The first factor of market condition mainly is defined by the market price of oil. Market condition drives production through various levels of drilling activities projected in the future. The second factor focuses on the trend related to operators' efforts to switch gas-fired compressors to grid-powered for the gas gathering and transportation segments, in the producing region. This decision of switching from gas-fired to electric for compressors is driven mainly for lowering the emission rating for the operators or producers for decarbonization. However, it would increase the reliability requirement of grid power for natural gas systems to ensure deliverability.

Table 1 demonstrates the combintations of two key assumpitons defining the forecast scenario. There are three price scenarios, low price ($35/bbl), base price ($70/bbl), and high price ($90/bbl). Then, there are four different levels of electrification assumption, represented by the average annual growth rate from the year 2021 within each chart. "Status quo" case – maintain the current 10 percent electrification with **0 percent growth**. This is used in the low scenario definition. A **1.2 percent annual growth** from 2021 to 2035 will reach around 30 percent of compressors' electrification used in the base scenario. A **3 percent annual growth** from 2021 to 2035 will reach around 58 percent of the electrification of compressors, and this is used in the high scenario. A **5.5 percent annual growth** from 2021 to 2035 will reach around 97 percent of the electrification of the compressor and is used as an upper bound in this analysis to indicate the full electrification case.

Table 1 Definition of Scenarios

Oil price ($/BBL)		Electrification level by the year 2035 for gas midstream (Percent)			
		0% Growth 10% Elec	1.2% Growth 30% Elec	3% Growth 58% Elec	5.5% Growth 97% Elec
	$35	X			X
	$75		X		X
	$90			X	X

Figure 1-2 shows a load forecast panel for the study area from 2012 through 2035, by varying market price and electrification levels. Each chart of the panel presents one single price scenario, with four different level of electrification assumptions.

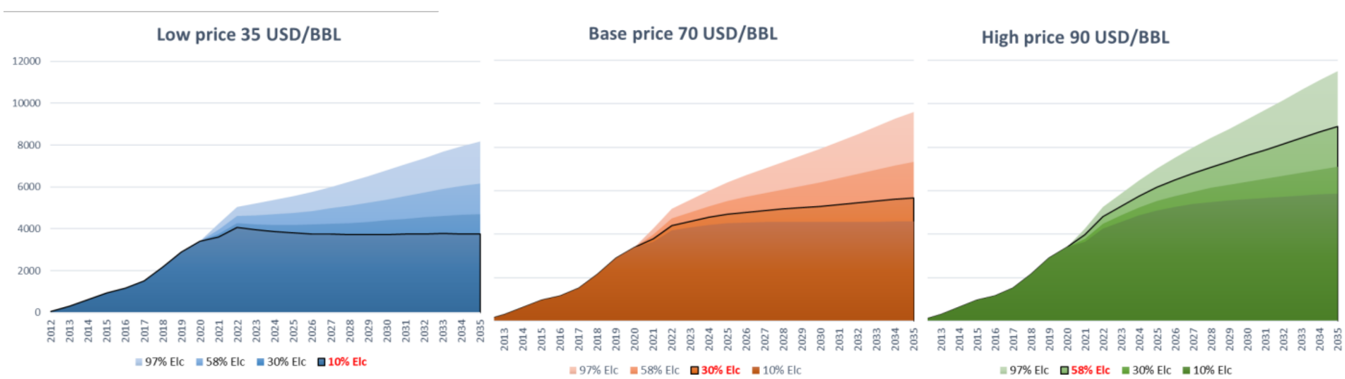

Figure 1-2 Projected load estimate by market price and electrification level

It is worth noting that the impact of electrification increases as underlying production increases, from the low price to high price scenarios. Taking the example of the year 2035 estimates, the range of outcomes is around 4400 MW of impact from 10 percent electrification assumption to 97 percent conversion in the low-price scenario. The range of outcome in high priced scenario grow to over 5600 MW of impact in the high-priced scenario, when comparing the estimated 2035 load under 97% electrification level versus 10% electrification level.

Among all possible scenairo combinations, three distinct combinations of these two factors are selected and defined as the study's base, high and low scenarios in Table 2.

For the base scenario with a long-term oil price of $70/bbl, and reaching 30% conversion in electrification for midstream by 2035, the total oil production is expected to continue rising through 2025 before stabilizing in the major production areas, like Delaware and Midland Basins. The total load requirement will increase by 58%, reaching 5682 MW in 2035, at a 3.5% compound annual growth rate for the forecasted period. The electrification of midstream will convert up to 30% of the current midstream load requirement to the grid.

The high scenario with a long-term oil price of $90/bbl and a more progressive electrification trend leading to 58% of the current midstream load by 2035, the total production will continue growing with a sustained drilling rate supported by high oil price in Delaware and Midland Basins. The total requirement of load will grow at a robust 6.6% compound annual growth rate for the forecasted period and reach almost 9000 MW by the year 2035, reaching 2.6 times the year 2020 level. This scenario combines with the most optimistic market condition and accelerates decarbonization efforts from the industry in operations to provide an upper bound for the future load.

Table 2 Aggregated load projection by scenario

Year / Megawatt	Low: $35 + 10% elec.	Base: $70 + 30% elec.	High: $90 + 58% elec.	$70 + 97% elec.
2025	3801	4922	6156	6382
2030	3739	5291	7623	7933
2035	3750	5682	8951	9618

With the low scenario with a long-term oil price of $35/bbl and a stagnant electrification level of 10%, the total oil production stays flat during the forecasted period. The reduced drilling efforts offset the decline of existing wells in the area. In the forecasted period, the total load requirement is reaching its peak at 3800 and then will stagnate through 2035. This scenario combines the most pessimistic and conservative assumptions to provide a lower bound for the future load. Furthermore, the key message of the low scenario is that the oil and gas associated load is steady even in the most pessimistic market condition, and a drastic decrease of the load requirement from this region is unlikely.

This research project was complex and touched on a wide range of technical, market, and engineering topics in the analysis. The information and assumptions are obtained from various sources, including industry interviews, public information, third-party data, expert inputs, academic research literature, and internal proprietary research across many disciplines (geology, economics, hydrology, engineering, etc.). There are some key assumptions included in the study.

- Electric submersible pumps, natural gas lift, and rod pumps are assumed to be the main choices for artificial lifts in the future, without major efficiency improvements or technological innovations. Pump efficiency is assumed to be constant through the forecast period. The pump efficiency could improve in the future, which would reduce the amount of load required. Although gas lift is efficient and does not rely on grid power, its usage will be limited when the water cut increases for future wells in Delaware and Midland Basins, and electric submersible pumps (ESP) or rod pumps will be used in its place in those circumstances.

- Water transportation is assumed to be done via pipeline or trucks in this study. Based on historical asset locations, the saltwater disposal facilities are assumed to be located an average of three miles away from the production wells. This assumption could change as water disposal sites are also determined by the location of the available reservoir for produced water. The depth of the water disposal wells has been increasing over time since 2012. The expectation is that the depth of the water disposal facilities will continue to increase as the operators are forced to use deeper reservoirs for disposal in the future. The water transportation load is not included explicitly in this study, although it is assumed to be a minor component if assuming a large diameter (20 inches) for around three miles.

- Compressors are assumed to be using only 10% of grid power for their load currently. They are expected to be converting to grid power as operators continue their efforts in decarbonization in the basin. This operation trend presents a major load additional to future load estimates, depending on the electrification level of the midstream operation.

- This study does not include the electric load of hydraulic fracking and drilling of the wells, because those activities rely mainly on on-site generators instead of the grid.
- This study does not include additional load impacts associated with new enhanced oil recovery (EOR) projects using CO_2 or emerging technologies like low carbon-based hydrogen (likely to increase the load to the grid) and distributed energy projects (likely to reduce the load to the grid).
- Production outlook is based on a conservative assumption that all capital required for drilling is from producers' internal revenue, without additional external loans, restricting the future drilling upside.
- This study only covers the average load estimates of each activity and does not consider peak hour demand versus non-peak.
- This study only covers the direct loads from upstream and midstream oil and gas activities and does not include residential and commercial loads in Permian that may be driven and related to the oil and gas activities.

Roadmap of the report

The rest of the report is organized in the following way:

Chapter 2 describes the historical oil and gas activities in the Permian Basin and the scope of this study. Chapter 3 explains the overall research approach for the project and data sources.

Chapters 4 and 5 explain each activity included in this study for load estimate. It details the oil and gas activities requiring electric power and establishes the knowledge and methodology in linking the activity to load requirement. These chapters also estimate the historical load by activity and county as a reference. These two chapters set the foundations of the load estimates and documented the methods and assumptions for modeling the forecasted scenarios.

Chapter 6 summarizes the production outlook based on the Tight Oil Resource Assessment Consortium (TORA) at the Bureau as the main source of the inputs for this project. This chapter explains the overall workflow of the production outlook and key assumptions based on a multidisciplinary body of research. Chapter 7 presents the load outlook by scenario for West Texas in the study area and discusses the definition of drivers for scenario development and the implications of the outlooks. Furthermore, this chapter also maps all load estimates (historical to future) to one-by-one mile blocks in the study area as a heat map of load occurrence. It explains the methodology and assumptions in mapping the load for the forecasted period.

Chapter 8 concludes the research with key findings and notes on additional future extensions.

Chapter 2. Overview of the Permian Basin

This chapter introduces the historical development of the Permian Basin and its historical oil and gas activities in the area.

2.1. Overview of the Permian Basin

The Permian Basin covers more than 86,000 square miles (220,000 km^2) (Ball, 1995). It extends across approximately 250 miles (400 km) wide and 300 miles (480 km) long, covering all or parts of 52 counties in West Texas and southeast New Mexico.

The Permian Basin is a large sedimentary basin with the name to indicate that it has one of the world's thickest deposits of rocks from the Permian geologic period. The Permian Basin developed in the open marine area known as the Tobosa Basin in the middle Carboniferous period, approximately 325 million–320 million years ago (Galley, 1958).

The Permian Basin of West Texas and Southeast New Mexico has produced hydrocarbons for about 100 years. It has supplied more than 35.6 billion barrels of oil and about 125 trillion cubic feet of natural gas as of January 2020. Implementing hydraulic fracturing, horizontal drilling, and completion technology advancements during the past decade has reversed the production decline in the Permian Basin, and the basin has exceeded its previous production peak, set in the early 1970s. 40% of the global demand is supported in the form of imports (either through pipe or LNG), as a total of 2000 BCM by 2030. The Permian Basin is one of the fastest-growing basins in the United States and worldwide. It has gained renewed momentum since the shale revolution in the early 2010s. Figure 2-1 and Figure 2-2 show how the U.S. proven reserve of liquid and gas since 1979. Starting from 2009, the U. S. oil reserves have doubled, and the gas proved reserve has also increased by 80%. In 2019, Permian Basin production accounted for more than 35% of total U.S. crude oil production and more than 13% of total U.S. natural gas production. The basin comprises several subbasins and platforms: three main sub-divisions include the Delaware Basin, Central Basin Platform, and the Midland Basin (EIA, 2020). The Delaware Basin straddles the Texas and New Mexico state line, producing significant volumes on the New Mexico side.

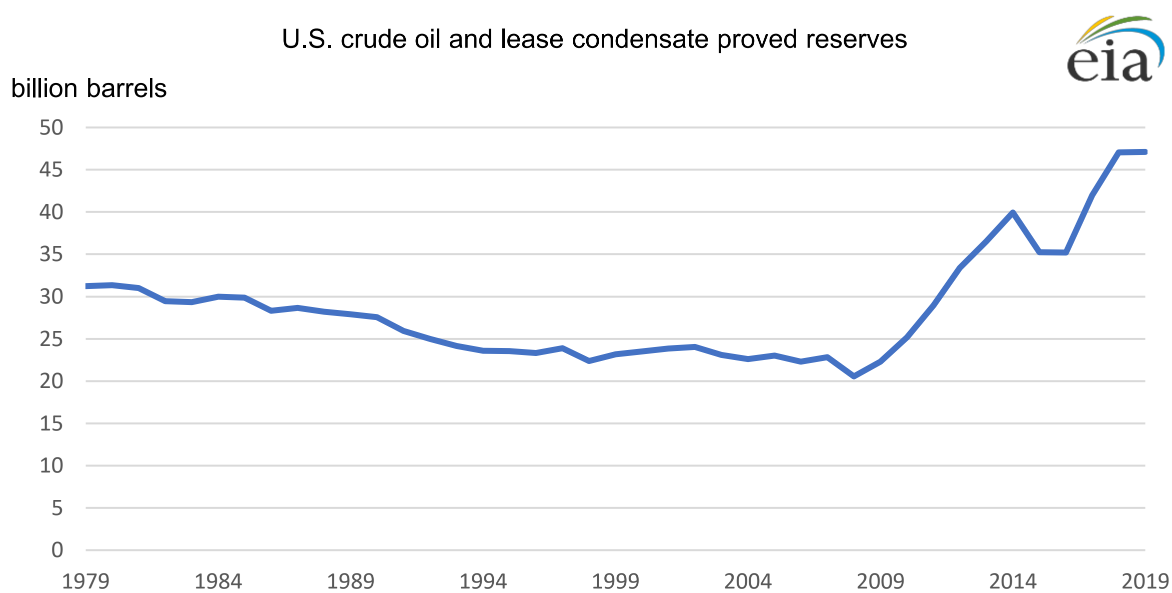

Figure 2-1 U.S. crude oil and lease condensate proved reserves

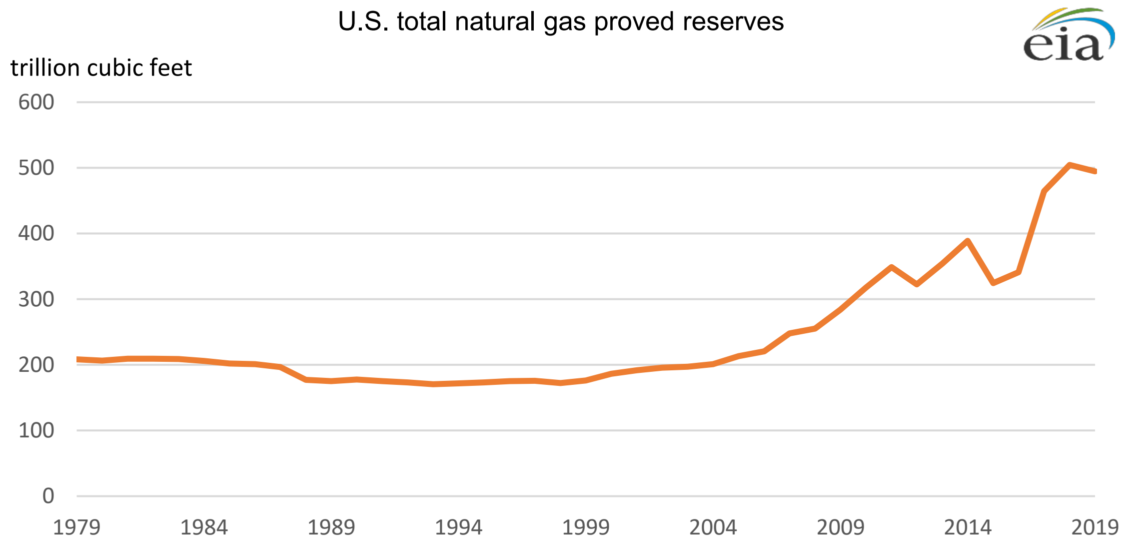

Figure 2-2 U.S. natural gas proved reserves

As of 2018, the Energy Information Agency (EIA) estimates that the remaining proven reserves in the Permian Basin exceed 11 billion barrels of oil and 46 trillion cubic feet of natural gas. The Permian Basin has become one of the largest hydrocarbon-producing basins in the United States and the world (EIA, 2019, Figure 2-3 and Figure 2-4), about 25% of the total U.S. proved reserve and 10% of the total natural gas proved reserve. It is crucial to U.S. oil and gas production.

By the year 2020, there were over 50,000 wells active in the study area of the Permian Basin, producing on average 4.4 million bbl per day of crude oil and 16.9 bcf per day of natural gas. The EIA noted that the Permian accounts for about 30% of U.S. oil production and 14% natural gas production in early 2021. The production numbers have reached even higher levels after 2020. As of March 2022, with the high oil price, the Permian oil production broke 5 million barrels per day, and natural gas almost 23 bcfd.

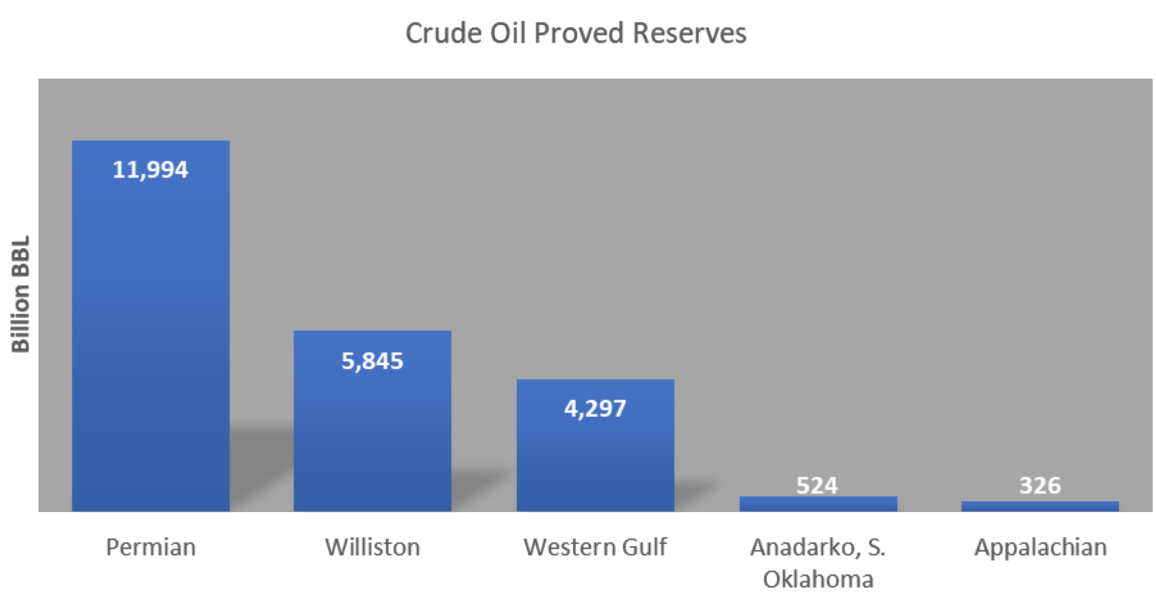

Figure 2-3 U.S. crude oil proved reserve by basin

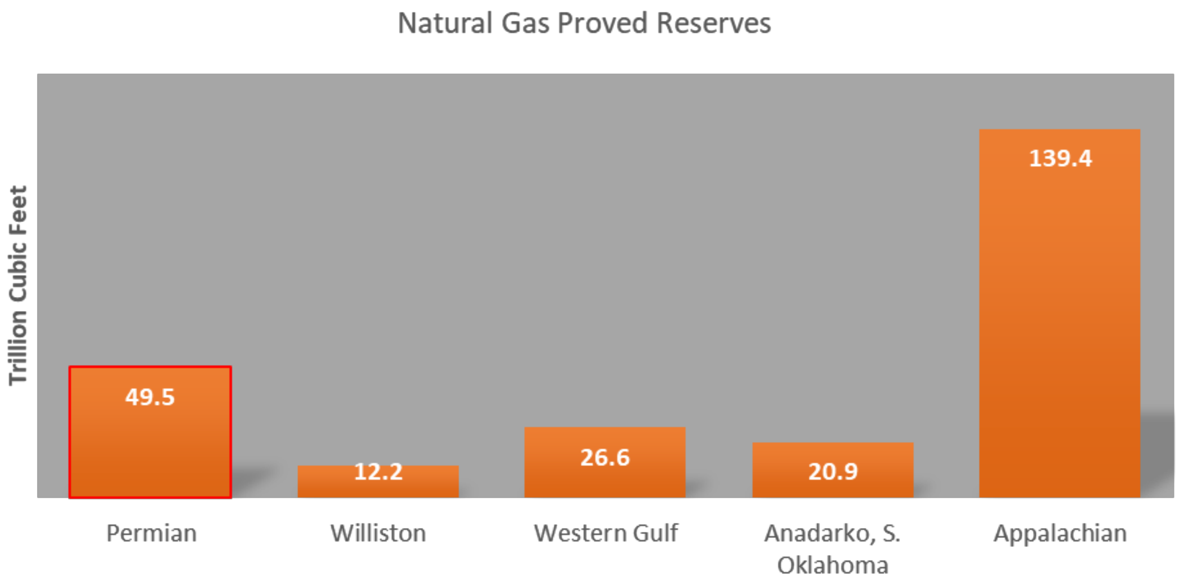

Figure 2-4 U.S. natural gas proved reserves by basin

2.2. The geographic scope of the study

Figure 2-5 shows the geographic location of the Permian Basin with its subbasins groups: the Midland Basin, the Delaware Basin, the Central Basin Platform, and other fringe subbasin groups.

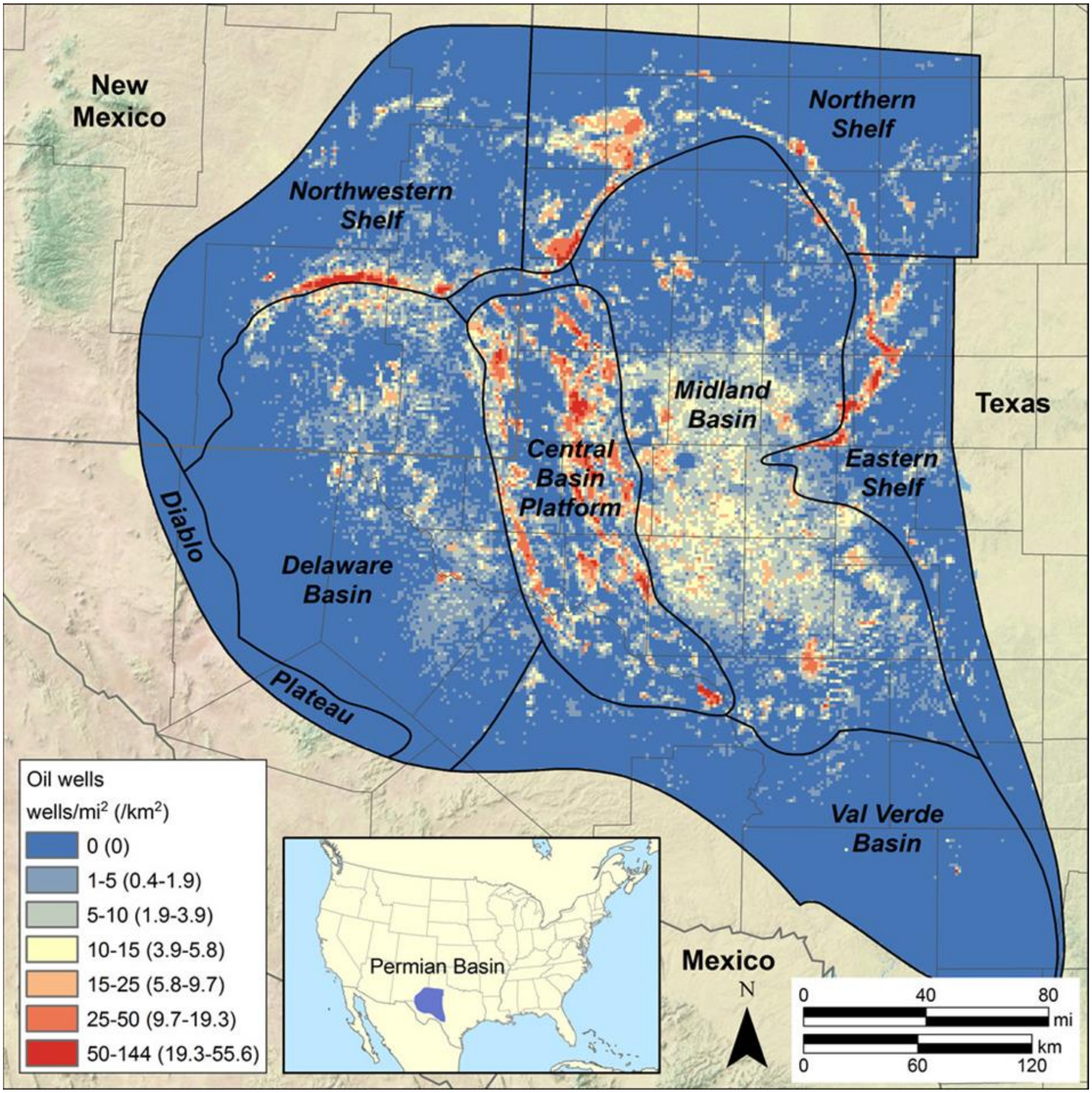

Figure 2-5 The Permian Basin geographic location

2.3. Oil and gas activity in the Permian Basin

Figure 2-6 shows the reported historical production of oil, gas, and condensates out of the Permian Basin within the state of Texas[1] since 2012. There are three types of production—oil in blue, gas in orange, and condensates in gray. Oil takes the major portion of the production out of the Permian, but gas production has increased its share of total production along with some additional condensates. It is important to note that the increasing gas production trend out of the Permian has to do with the geological characteristic of the basin. Because most of the gas is produced along

[1] This includes all counties in West Texas.

with oil, it is called associated gas. Figure 2-7 shows the same reported historical production (oil, gas, and condensates combined) out of the Permian by subbasin groups, which clearly shows where most of the production is coming from, the Midland and Delaware Basins, representing about 40% of geographic location accounts for 95% of the production.

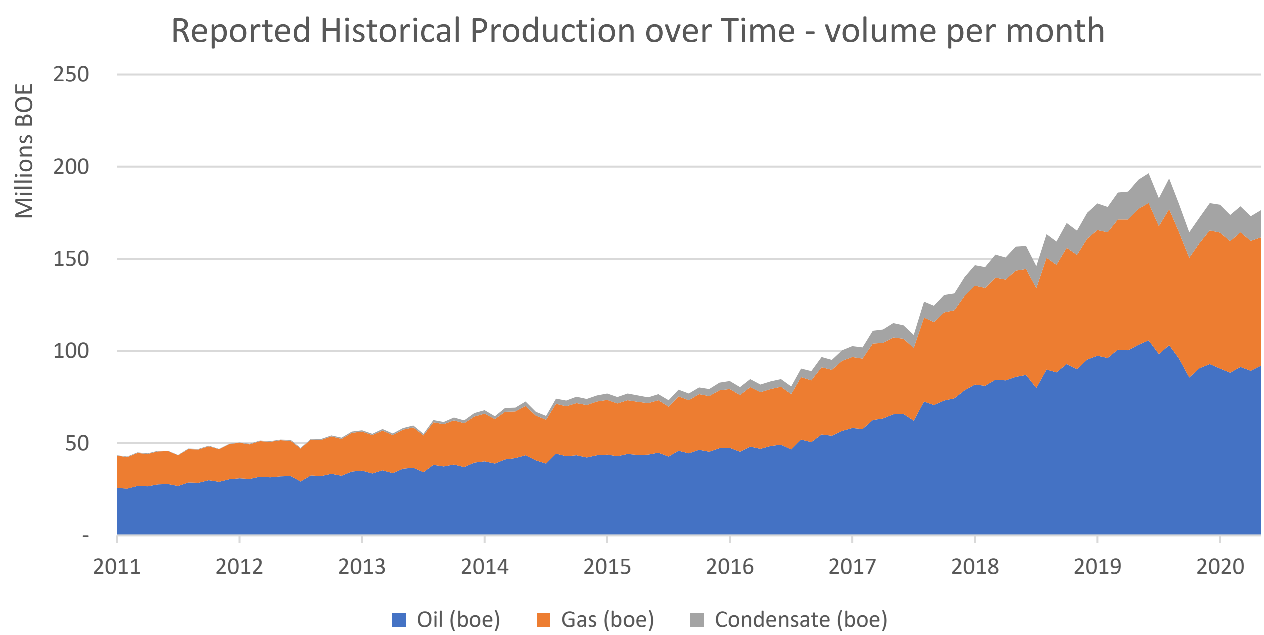

Figure 2-6 Production of the Permian Basin (Texas) since 2011

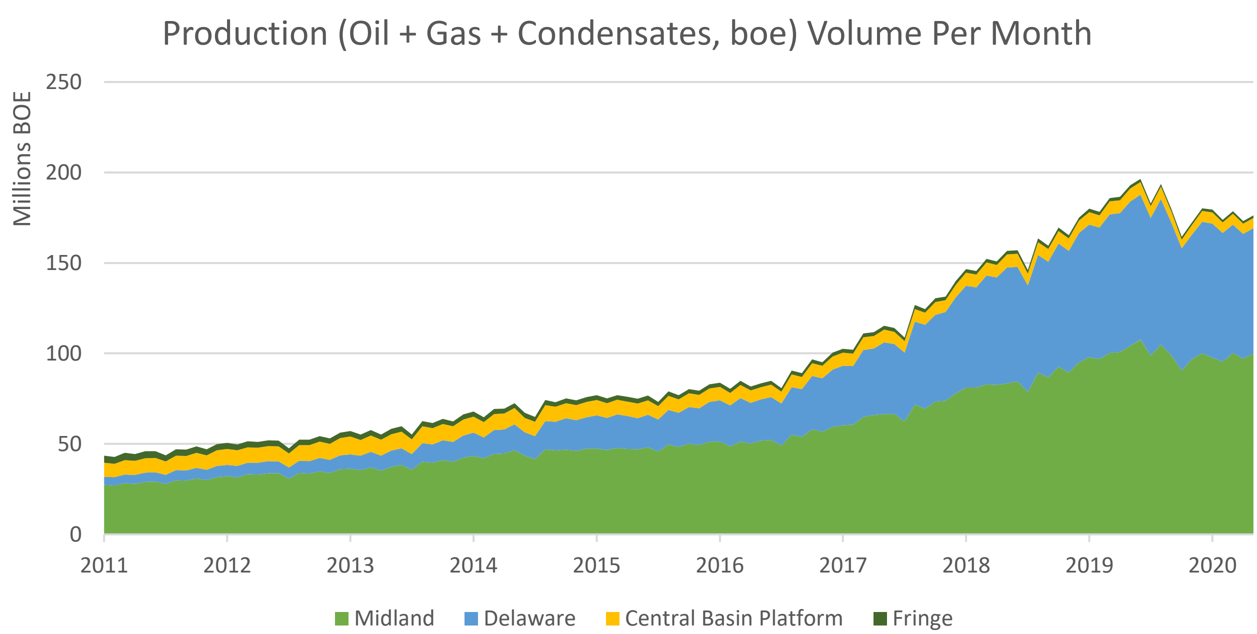

Figure 2-7 Permian production volume by subbasin since 2011

Since this study focuses on the electricity estimates related to oil and gas activities, it is also important to track and note the level of activities based on measures rather than productivity. Figure 2-8 shows the well activities in the Permian Basin since 2012. There are over 50,000 accumulated well completions reported since 2012. Well completions are a good indicator of activity level, but it is not equivalent to the number of wells active in the basin. Active wells include new wells being completed every year while existing wells are completed and added to continuing production. When we look at the production from each year, we count all wells that produced hydrocarbon. For example, in 2019, there were over 30,000 wells active.

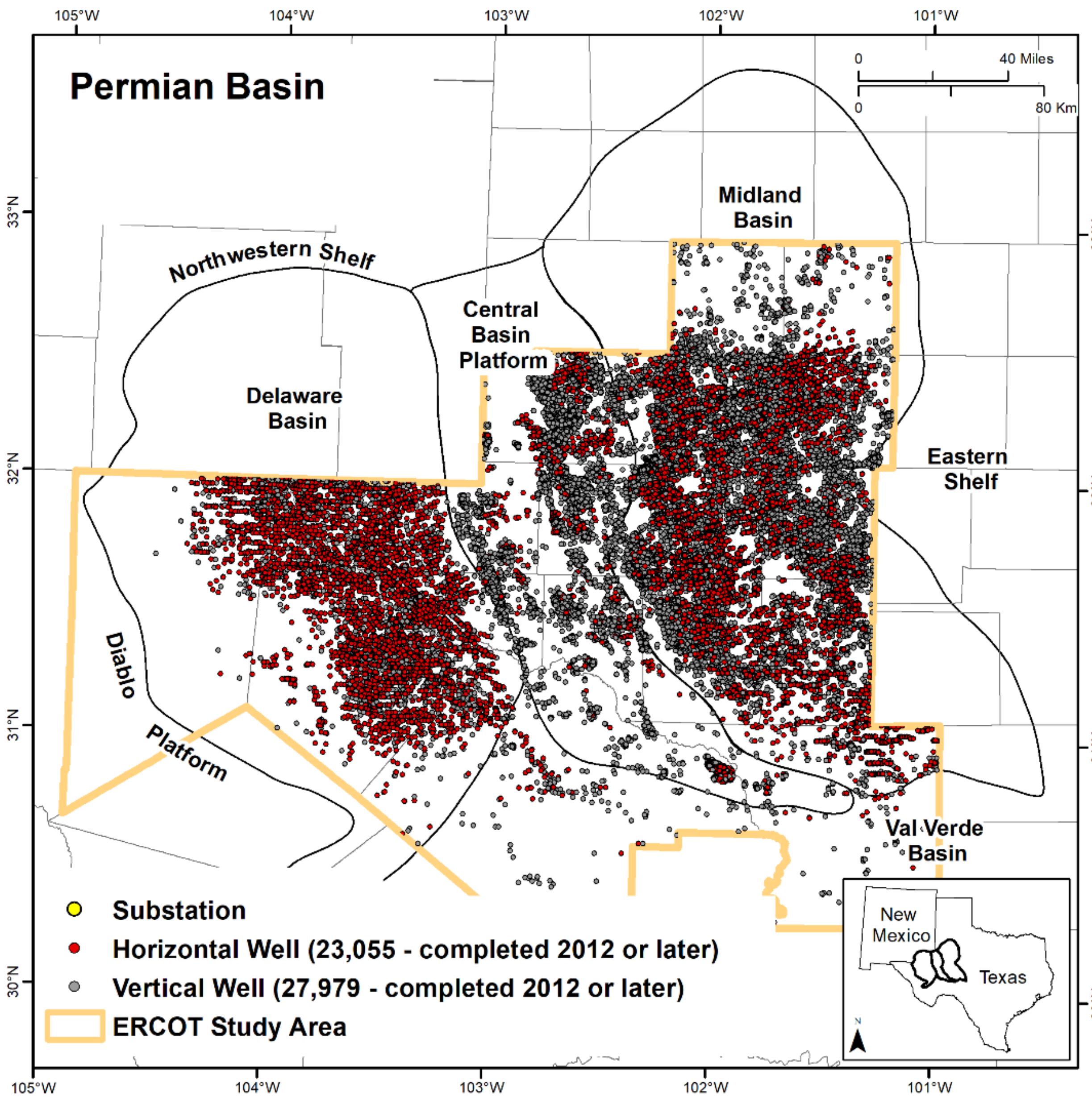

Figure 2-8 Well activities in the Permian Basin (Texas) since 2012

2.4. Historical activity level

Modeling load requirement necessitates measuring oil and gas activities in different ways. Following are the types of oil and gas activities data used in this study.

Operators in Texas report multiple aspects of their operation to the Rail Road Commission of Texas, which includes well logs and oil and gas production, the data source of historical production, and drilling activities.

There are two aspects of measuring well activity level; one is on looking at the number of wells, and the other is production level. Figure 2-9 plots the number of wells by their type from 2012 to 2021. H stands for horizontal wells, and V stands for vertical wells. There is a significant growth in the number of wells drilled in horizontal and vertical. With horizontal drilling and hydraulic fracturing innovation, horizontal wells had a sharp increase and surpassed the number of wells compared to vertical wells around 2018 in the study area.

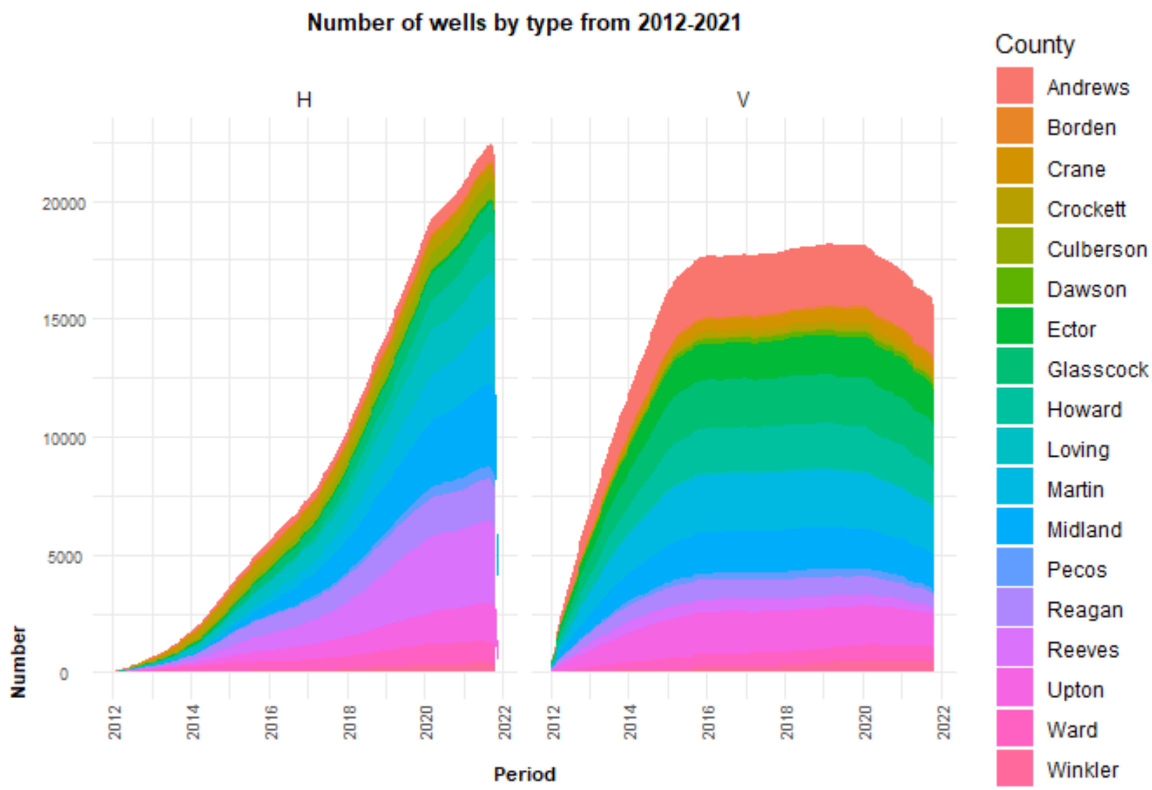

Figure 2-9 Number of wells by type from 2012 to 2021

Instead of using aggregated production over a month, the load-requirement calculation uses the daily production rate to estimate the average load capacity. Therefore, it is the daily production of crude oil (liquid), gas (unprocessed gas), and produced water used for upstream load calculation. Based on historical upstream data, we observe 2-4 horizontal wells per well pad in the study area. The number of wells per pad could influence the operation cost per well by creating cost-sharing among wells, although there is a limit on the number of wells installed at each pad. The load of upstream activities is mainly determined by its flow rate, and the number of wells per pad would more impact the cost of man-camps and the amount of needed equipment, which is relatively minor.

Although it is relatively simple to understand that more wells imply higher activities level, multiple factors could be used in measuring the level of oil and gas activities, and the activity level changes based on technology and market conditions over time. Furthermore, production and drilling depth can bring additional information about activity levels besides the number of wells. Figure 2-10 illustrates this point by showing the crude oil production by well type in the same period as Figure 2-9 – vertical wells with comparable numbers but much lower productivity. In contrast, horizontal wells drive most crude and gas production out of the basin.

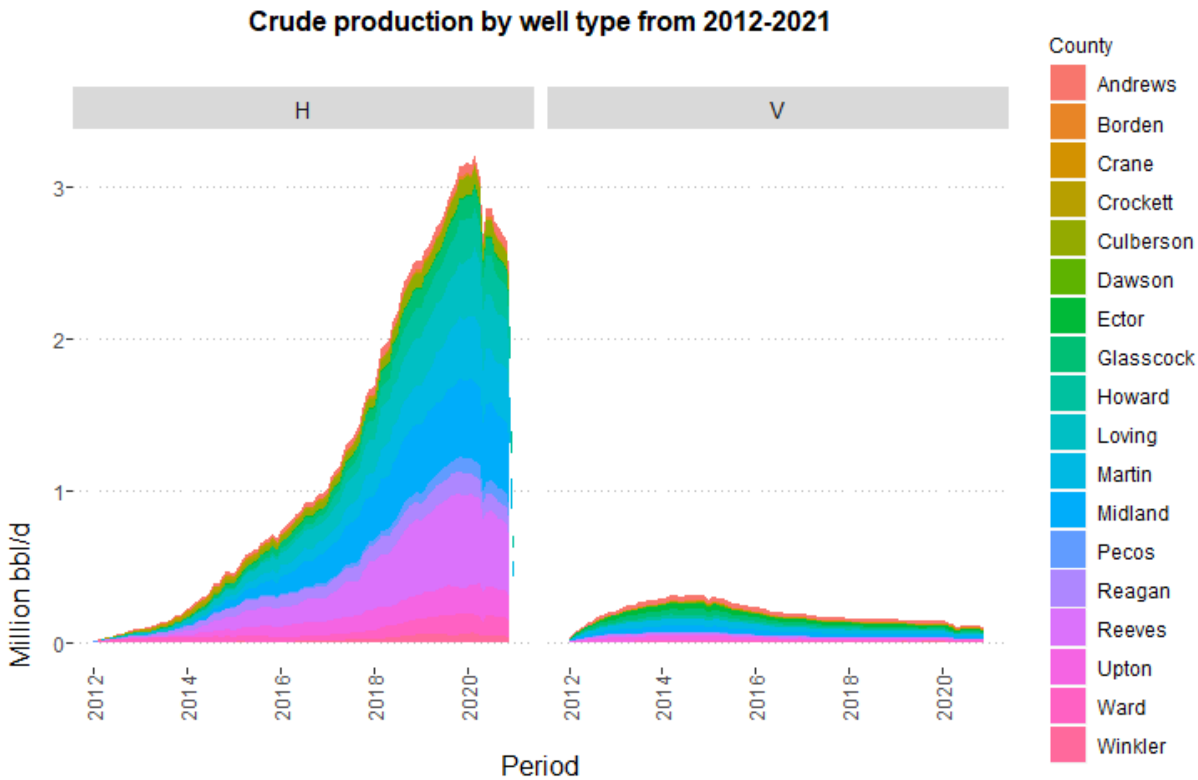

Figure 2-10 Crude productions by well type from 2012-2021

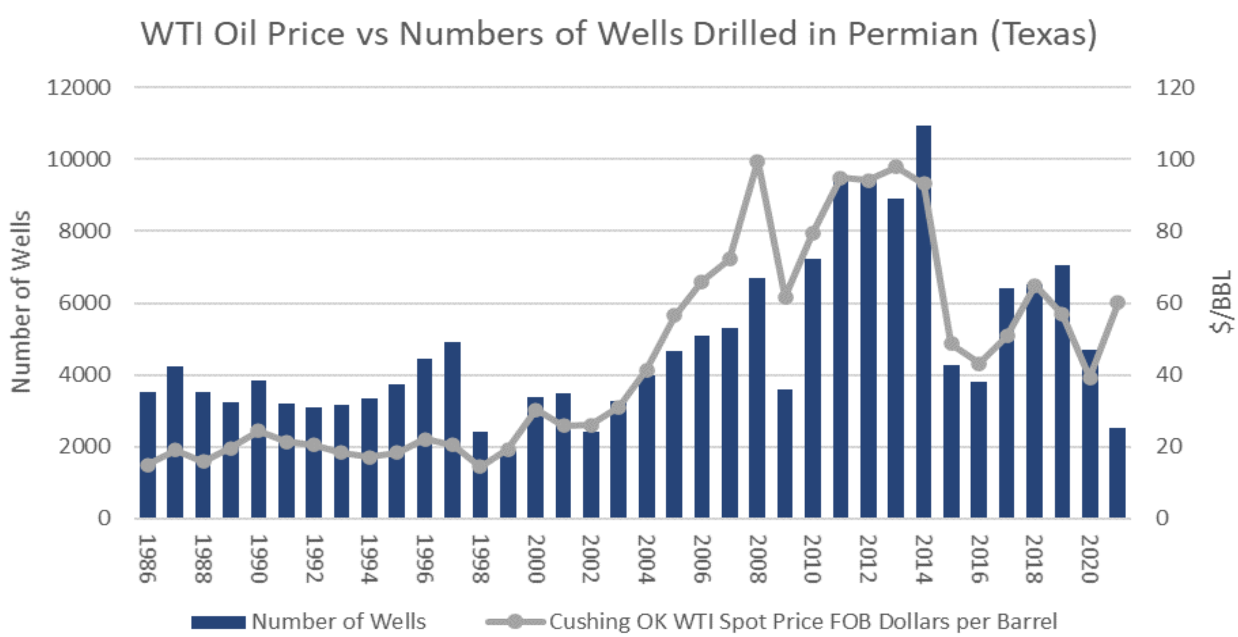

Figure 2-11 West Texas Intermediate (WTI) oil price versus numbers of well drilled in the Texas portion of Permian

Furthermore, besides productivity which is a function of subsurface formation and other technical decisions, the market price of the products also contributes to the behavior of drilling. Figure 2-11 plots the WTI oil price versus the number of wells drilled in the Texas portion of the Permian over time from 1986 through 2021. The wells drilled have correlated closely with the oil price as it indicates the market condition and the expected profitability of the operation for the following months. For example, an average of 8,000 to 9000 wells were drilled per year from 2012-to 2014 while oil prices were above $80 per barrel, and the drilling activities dropped to close to 4,000 wells per year when the oil price dropped to about $40 per barrel in 2016. The drilling activities responded to the oil price recovery back to above $60 per barrel in 2018 again, followed by a similar impact of a slowdown in drilling in 2020 when the oil price dropped below USD 40 per barrel.

Chapter 3. Research structure and study outline

This study combines the existing TORA research on the production outlook of the Permian Basin with additional modeling on load-requirement assessment. As a result, it delivers a locational-based electric load-requirement outlook for oil and gas activities on the Texas side of the Permian Basin under the ERCOT market area. There are two major objectives of this study:

- Establish a sustainable process in developing the load outlook of oil and gas activities in the Permian.
- Develop a knowledge base of the relation between electric load demand and oil and gas activities.

3.1. Research methodology

The research work is accomplished through two phases.

Phase 1 develops a load impact model of upstream oil and gas activities in the Permian based on historical data and a quantitative knowledge base of electric load generated from oil and gas activities. The oil and gas operation activities are as follows:

- Upstream operations include drilling and production activities over the life cycle of a well or pad.
- Midstream operations include gathering pipeline systems that transport liquids and gas from wellpads to treatment plants and refineries and any transportation pipeline systems (including intrastate and interstate pipelines) starting from the outlet of treatment plants located in the Permian Basin (within Texas).
- Water treatment and disposal are likely to become a critical issue in the future and generate increasing load demand for operations, requiring the separation of water and hydrocarbons.

Through historical data and industry interviews, key drivers that contribute to load requirements for oil and gas activities are defined numerically as the basis of the load model. The results from phase 1 are covered in Chapters 4 and 5.

Phase 2 of the project builds a sustainable process in developing the load outlook of oil and gas activities in the Permian. This phase includes two workstreams. One is to develop a set of long-term load forecasts based on upstream oil and gas activities in the Permian. The other is to train and transfer the knowledge through project workshops and training to ERCOT technical teams. Instead of one scenario, there are three scenarios developed in this study to provide more robust references of alternative market outlooks and operation assumptions.

3.2. Technical interviews and data sources

In the first phase of the study, there are several rounds of technical interviews and surveys to collect inputs and assumptions from industry and experts in the field, ranging from upstream operators and leaseholders, midstream pipeline companies, and regulatory entities like the Texas Commission of Environmental Quality. In addition, there are multiple interviews with researchers and scholars that are subject experts in technical areas, like EOR, air emission from compressors, and petroleum engineering modeling.

Furthermore, the study has leveraged an extensive list of data sources to compile the necessary information for modeling purposes, covering many disciplines from the subsurface, engineering, and market data to environmental reporting.

Chapter 4. Assessment of the load requirement for upstream activities

Chapter 4 explains each activity included in this study for the upstream sector and its impact on load requirement.

Definition of upstream activities Figures 4-1 shows a cartoon schematic of all value chain activities covered in this study. It describes the activities from the wellhead to the end of midstream activities, where the hydrocarbon is processed and transported to market.

The oil- and gas-industry activity can be divided into three major sectors: upstream (or exploration and production-E&P), midstream, and downstream. The upstream sector is all about searching for the potential location of underground resources, drilling exploratory wells, if successful, and then drilling and operating the wells that recover and bringing the crude oil or raw natural gas to the surface. Exploration involves obtaining a lease and permission to drill from the owners of onshore or offshore acreage thought to contain oil or gas and conducting necessary geological and geophysical surveys required to explore for (and hopefully find) economic accumulations of oil or gas.

The next step is drilling an exploratory well, which is the only way to validate results from the surveys and is physically creating the boreholes in the ground that will eventually become an oil and gas well. The work is done by a rig contractor and service companies in the oilfield service sector. This study does not assess load requirements for exploration and drilling activities leading to production. For most exploration wells, operators usually will not rely on grid-connected power or will not invest additional capital costs to support ongoing production yet at this stage.

Upstream defined in this study covers the production activities after exploration activities, and the goal is to maximize the recovery of hydrocarbons from subsurface reservoirs. There are different stages throughout the life cycle of a well:

- Efficiently recovering the oil and gas in a producing field using primary and secondary recovery methods
- Tertiary or EOR
- Plug and abandonment, which marks the end of the productive life of a well. That event can occur anywhere from a few years after the well is drilled to five or six decades later.

The upstream production activities include four fundamental operations: lifting, separating, treatment, and reinjection, and most of the wells drilled in the Permian are in the primary and secondary recovery stage.

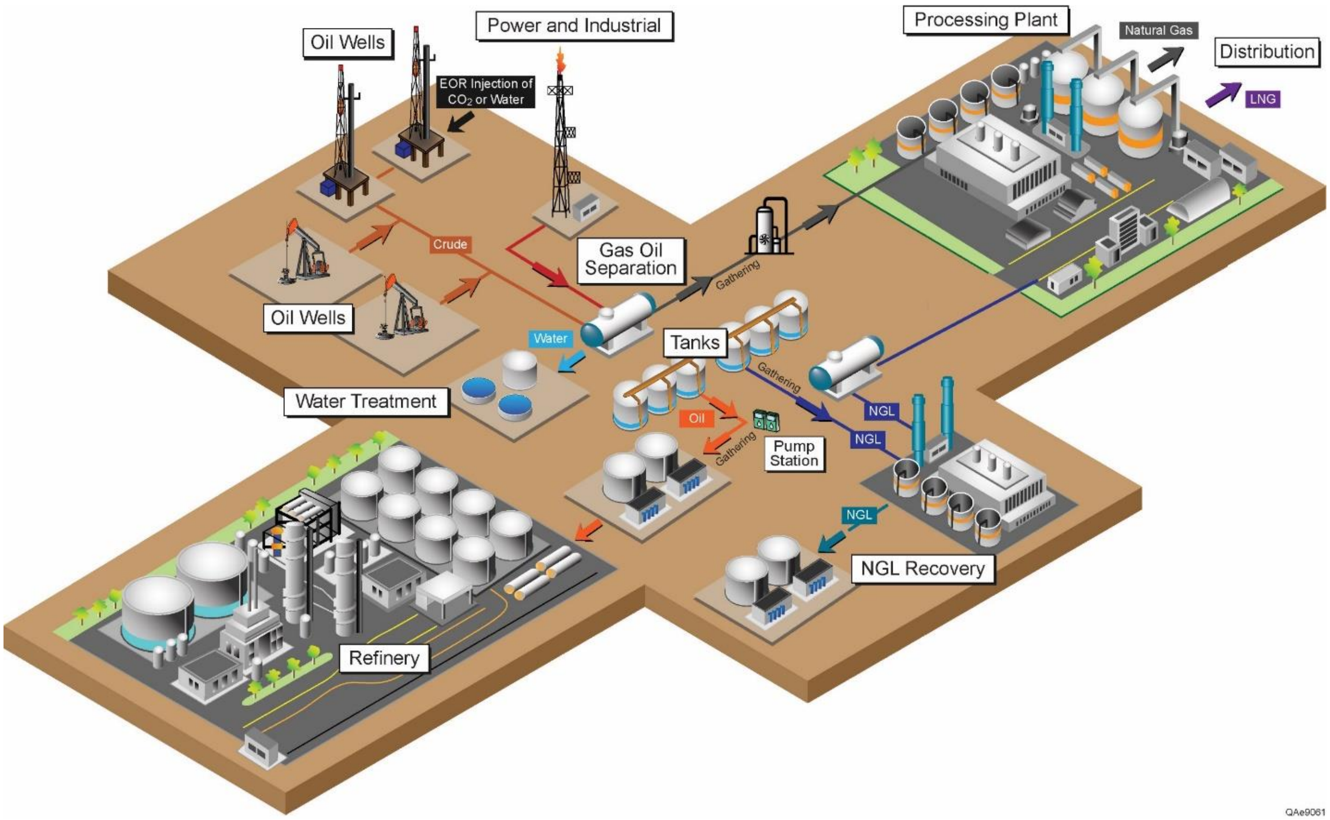

Figure 4-1 Oil and gas activity schematic

4.1. Lifting

Lifting the crude and associated water and gas from the reservoir is done under reservoir pressure or by mechanical means (artificial lifts). Reservoir depth and pressure determine when it is necessary to use an artificial lifting mechanism. Crude oil is generally produced as a mixture of oil, water, and gas, which must be separated.

Reservoir pressure is determined by gas and water pressure in contact with oil. Oil production generally reduces resource pressure over time, and gas and water can be injected to maintain reservoir pressure.

Most wells' initial production can be supported by natural flow due to the high pressure of the reservoir at the beginning. After the initial explosive pressure, the pressure starts to dissipate. That is a serious issue for oil and gas production; as the pressure drops, so will the production flow if additional measures are not taken.

Figure 4-2 plots the type curve per subbasin in the Permian: the x-axis is the number of months while the y-axis is the production rate. This provides an overview of the average life cycle production profile, called the type curve (or decline curve) of wells in the Permian. A decline follows a clear pattern of high initial production in flow rate. The artificial lift strategy is needed to maintain a higher flow for the wells. Artificial lifting by pumping or gas lift increases oil production with insufficient reservoir pressure. Ninety percent of wells need an artificial lift at some stage of their production life.

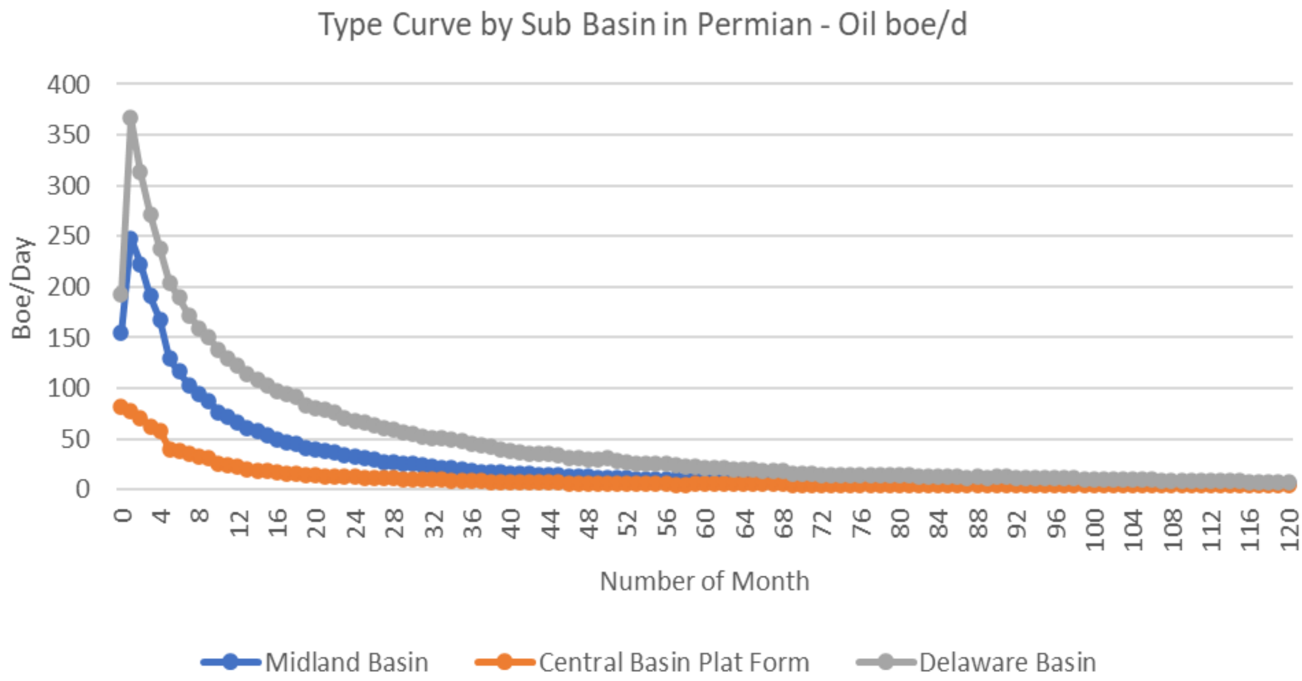

Figure 4-2 Type curves by subbasin in the Permian of oil production from 2012-2020 data

Pumping is a pump located either on the surface or in the well (downhole), although the detailed design and mechanisms differ depending on the type of lift or pump.

For example, gas lifting consists of injecting gas at one or more points in the production tubing. Pumping energy is based on turbulent flow for friction drop of 0.1 psi per 100 feet through a 3-inch production pipe, reservoir depth, crude density, and flow rate. The energy for the artificial lifts is supplied by electricity, either generated on-site from produced gas, imported natural gas, diesel fuel, or grid-based electricity. The energy source is a key factor in determining greenhouse gas (GHG) emissions of the well site operation.

Production wells in unconventional reservoirs require a flexible artificial lifting strategy because of a wide range of production rates and a high decline rate of well productivities with depletion and time.

There are several types of artificial lifts used in the Permian. Figure 4-3 shows a graphic demonstration of different methods of artificial lifts in the industry right now. The four major types observed in the Permian Basin are electric submersible pumps [ESP], rod pumps, plunger lifts, and gas lifts. Operators can switch and change artificial lift options throughout the production process with a specific objective depending on multiple factors.

Table 3 describes a list of factors producers consider in selecting artificial lift options during production, with the four types in the Permian highlighted in gray. There are many factors to consider for the artificial list process. The conditions and selection could also change throughout the life cycle: Determining the best artificial lift option is a complex and dynamic process.

Besides technical factors, the market conditions have also driven operators to reconsider their artificial lift strategies over time. The Permian Basin did not have a gas lift 30 years back, while ESP was used to maximize early production in the early years, before 2016, especially in a high oil price environment. ESP has a wide range of operations for depth and operating flow rate. ESP could help boost the initial production effectively. Since 2016, when the oil price dropped, there was a shift in focus from ESP to gas lift for two reasons: first, the high gas contents from the unconventional wells in the Permian limit the performance of ESP, and second, the operators are shifting their operating mentality from drilling to sell to maximizing the net present value.

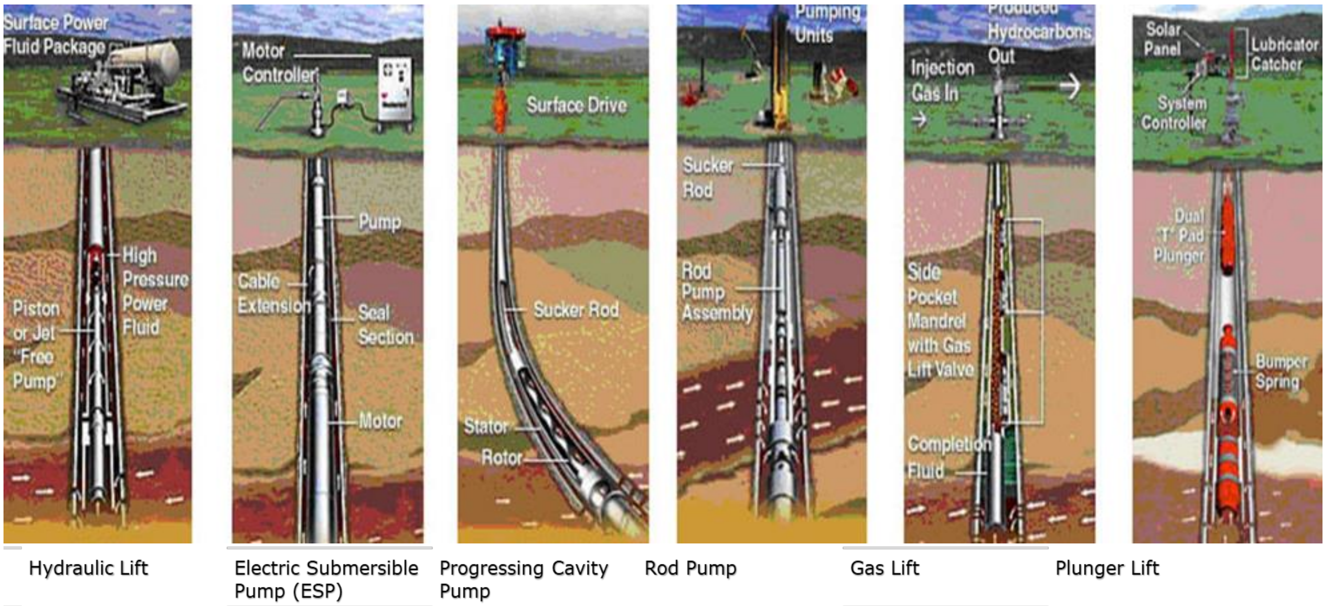

Figure 4-3 Artificial lift methods (Weatherford Artificial Lift Type Selection, Jul 2017)

Although there has been a shift from ESP to gas lifts in recent years, there is no set of defined rules for when to switch between different artificial lifts. The executed strategy in the field depends on the wells' conditions and the existing knowledge and experience of artificial lifting methods by most operators.

Table 3 Factors to consider in artificial lift selection[2]

Factors	Hydraulic Piston	Electrical Submersible Pu mp	Progressive Cavity	Rod Pump	Gas Lift	Plunger Lift
Operating Depth (ft TVD)	7,500-17,000	1,000-15,000	2,000-6,000	100-16,000	5,000-15,000	8,000-19,000
Typical Operating Volume (BARRELS PER DAY)	50-4,000	200-30,000	5-4,500	5-5,000	200-30,000	50-500
Operating Temperature (°F)	100-500	100-400	75-250	100-500	100-400	130-500
Corrosion Handling	Good	Good	Fair	Good to Excellent	Good to Excellent	Excellent
Gas Handling	Fair	Poor to Fair	Fair to Good	Fair to Good	Excellent	Excellent
Solids Handling	Poor	Poor to Fair	Excellent	Fair to Good	Good	Fair
Fluid Gravity (°API)	>8	>10	<35	>8	>15	GLR required 300 SCF/bbl
Build Angle	<15°/100	<10°/100’	<15°/100	<15°/100	N/A	N/A
Servicing	Hydraulic or Wireline	Workover or Pulling Rig	Workover or Pulling Rig	Workover or Pulling Rig	Wireline or Workover Rig	Wellhead Catcher or Wireline
Prime Mover	Multicylinder or Electric	Electric Motor	Gas or Electric	Gas or Electric	Compressor	Well’s Natural Energy
Overall System Efficiency (%)	45-55	35-60	40-70	45-60	10-30	N/A unless compressed gas added

Most wells use artificial lifts throughout their lives in the Permian Basin with a brief period of natural flow at the beginning of the well's life cycle, if any at all. Based on technical interviews with major operators and literature review, there are three types of flow strategies, as the major types in Permian–gas lift, ESP, and rod pump. A plunger lift is another type of lift that is often used as a tandem to gas lift in the later part of the well life. It is included as part of the gas lift.

The flow chart in Figure 4-4 describes the three major strategies used throughout the life of a well based on the industry interviews. From general observations among more than 270 operators on university land acreage in the Midland Basin,

[2] Source: Energy efficient activation, February 2014, ipieca.

small and large operators follow their peers of similar company size on artificial lift strategies. Smaller operators generally start wells using an ESP and convert to rod pumps once liquid fluid rates are below 350 to 400 bbl/d (Pradhan and others, 2017, 2018). After some early trials, larger operators generally use gas lifts before converting to rod pumps. However, companies that use gas lifts may also delay the conversion to rod pumps by using gas-assisted plunger lifts for several years.

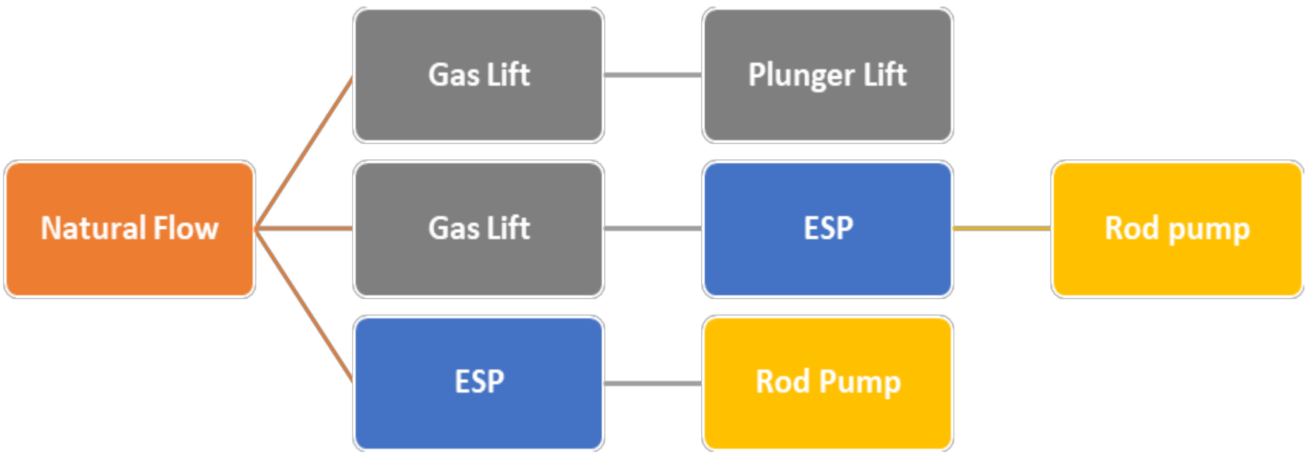

Figure 4-4 Artificial lift strategies throughout the life cycle of a well

A multinomial-probability regression estimates the probability of each artificial lift type used throughout the lifetime of a well based on historical production test data reported to the Texas Railroad Commission. The independent variables include depth of wells, the daily flow rate of liquid, water percentage to liquid ratio, and gas to liquid ratio.

Figure 4-5 is a probability graph based on the simulation regression from production data for all producing wells in the Texas part of the Permian.

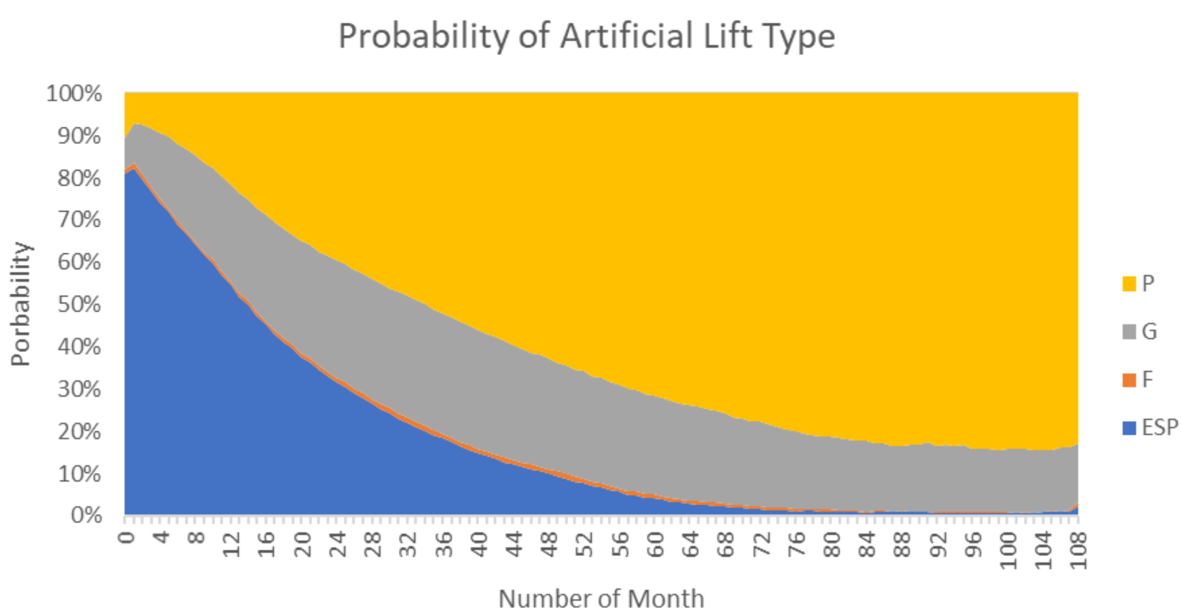

Figure 4-5 Probability of artificial lift type throughout the life cycle of a well

The artificial lift strategy is locational-based, depending on the water percentage in the mixture and GOR, per the inputs from the operators. Figure 4-6 shows the different levels of water cut and gas to the liquid (GTL) ratio by county in West Texas.

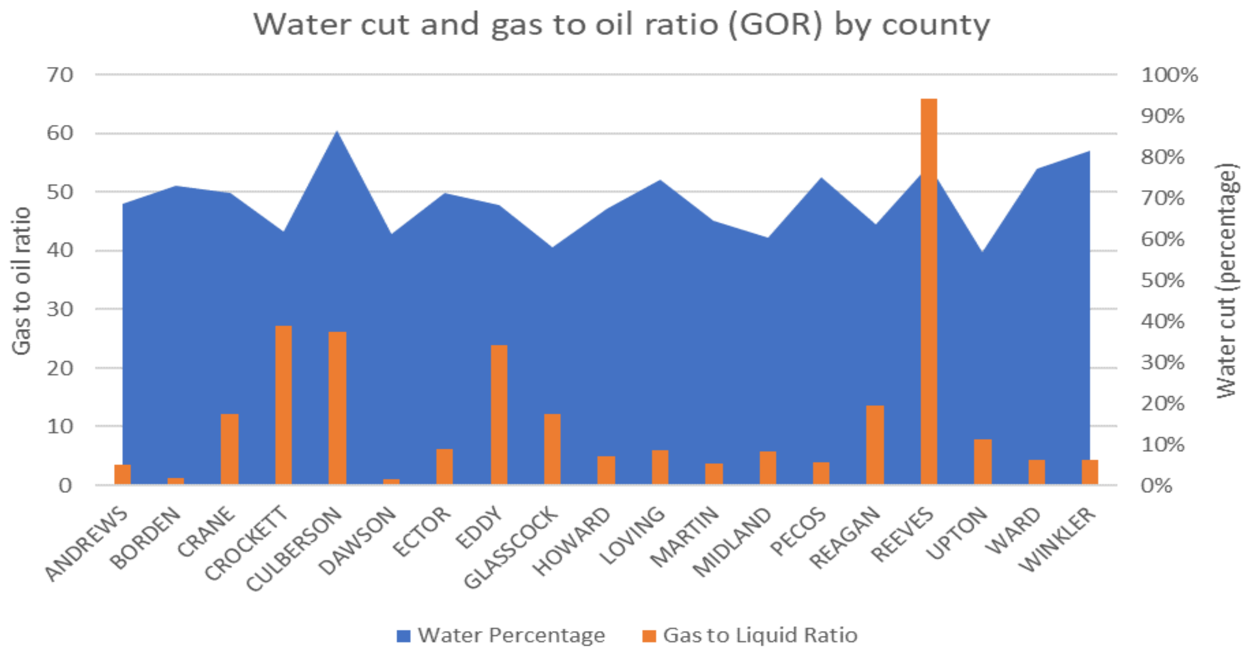

Figure 4-6 Water cut and GTL ratio by county

Due to the location difference, the probability of artificial lift strategy varies. Figure 4-7 illustrates the simulated results for Midland County and Culberson County, which have different water percentages (water cut) and GTL ratios.

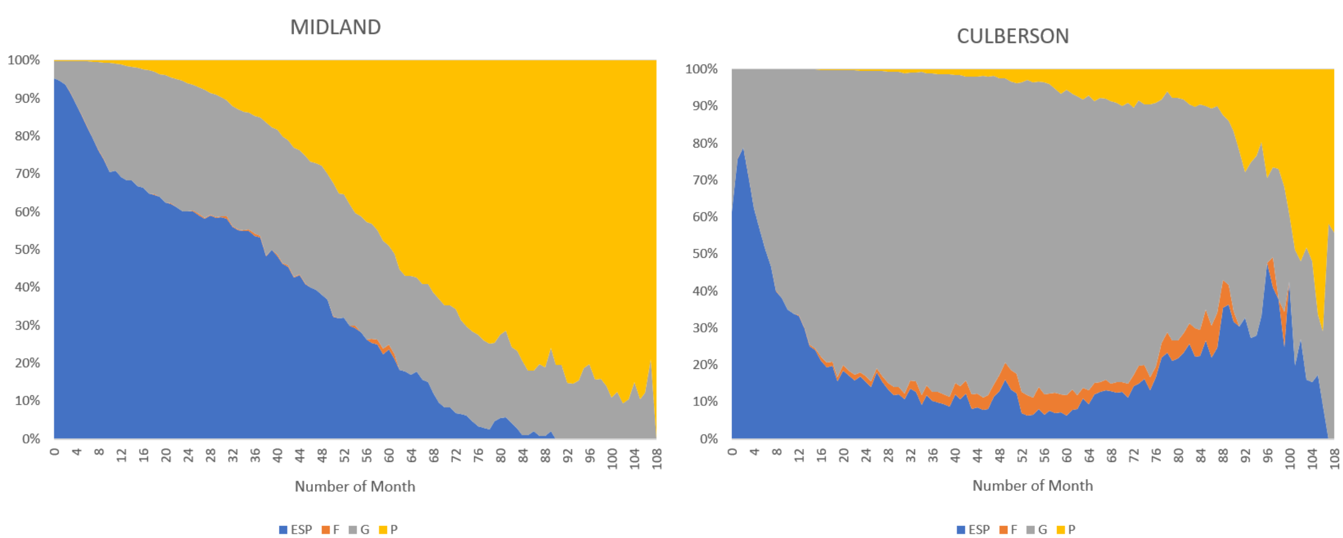

Figure 4-7 County-level artificial lift strategy comparison: Midland versus Culberson

Once an artificial lift strategy for a given well at its production stage is defined, one can calculate the expected energy requirement for the operation. All artificial lifts are expected to run continuously. Different artificial lift options have different energy requirements and preferred power sources–gas lift uses electricity generated from produced gas without any electricity. In contrast, other pumps mainly use electricity at different levels of efficiency. There are five steps to calculate the power requirement for artificial lift options which is demonstrated in Figure 4-8:

1. Determine the fluid density (lb./bbl)
2. Calculate the energy required to lift the fluid by unit depth (kilowatt-hour/bbl/1000 ft)
3. Calculate the horsepower-hour to lift the fluid by unit depth considering well efficiency and pump efficiency (HP-h/ bbl/1000 ft)
4. Calculate the horsepower requirement to lift the total production fluids (oil and water) for a given production rate and well depth (HP)
5. Calculate the cost of power (cent/ kilowatt hour)

**Color code*

= input parameters

= output parameters

1. Determine the fluid density (lb/bbl)

**Input parameter: Oil and Water API*

Fluid	Degree API [-]	Specific Gravity [-]	Density [kg/m3]	Density [lb/bbl]
Oil	40	0.825	825	289
Water	10	1.000	1000	351

2. Calculate the energy required to lift the fluid by unit depth (kWh/bbl/1000 ft)

Fluid	Density [lb/bbl]	Depth [ft]	Energy [kWh/bbl/1000 ft]
Oil	289	1000	0.109
Water	351	1000	0.132

3. Calculate the HP·h required to lift the fluid by unit depth considering well efficiency and pump efficiency (HP·h/bbl/1000 ft)

			Pump efficiency = 0.58	Pump efficiency = 0.16	Pump efficiency = 0.15	Pump efficiency = 0.48
Fluid	Energy [kWh/bbl]	Well Efficiency	Rod Pump (HP·h/bbl/1000 ft)	Hydraulic Pump (HP·h/bbl/1000 ft)	Gas Lift (HP·h/bbl/1000 ft)	ESP (HP·h/bbl/1000 ft)
Oil	0.109	0.75	0.34	1.22	1.30	0.41
Water	0.132	0.75	0.407	1.48	1.57	0.49

4. Calculate the HP required to lift the total production fluids (Oil + water) for a given production rate and well depth (HP)

**Input parameter: production rate and well depth*

Fluid	Production [bbl/d]	Depth [ft]	Rod Pump (HP)	Gas Lift [HP]	ESP [HP]
Oil	50	9500	7	26	8
Water	50	9500	8	31	10
Total	100.00	-	14.70	56.84	17.76
Water cut	**50%**				
Grid power			**100%**	**0%**	**100%**

5. Calculate the Cost of Power

	6 cent / KWh	2 cent/KWh	6 cent / KWh
	Rod Pump [$/hr]		ESP [$/hr]
	$ 0.66		$ 0.79

Figure 4-8 Artificial lift load-requirement calculation

Through technical interviews, there are additional factors that operators have mentioned as part of the consideration process regarding artificial lift strategy in terms of balancing costs and performance. Besides the energy consumption that is calculated above, here are some additional factors:

ESP and gas lifts have similar operating costs, assuming 2 cents per kilowatt for gas and 5-6 cents per kilowatt for power off the grid. Of course, some operators with smaller operators have less favorable rates, while larger operators may have a negotiated lower electricity price from local utilities, like in Figure 4-9.

ESP has a higher maintenance cost and higher probability of workover, as shown in Figure 4-10 (Oyewhole, 2016; Yogashiri and others, 2018). This is an important factor against ESP usage as workover implies higher costs and longer downtime. There is always the chance for additional uncertainties of production performance after a shutdown. Hence, this factor drives operators to gas lifts for that consideration.

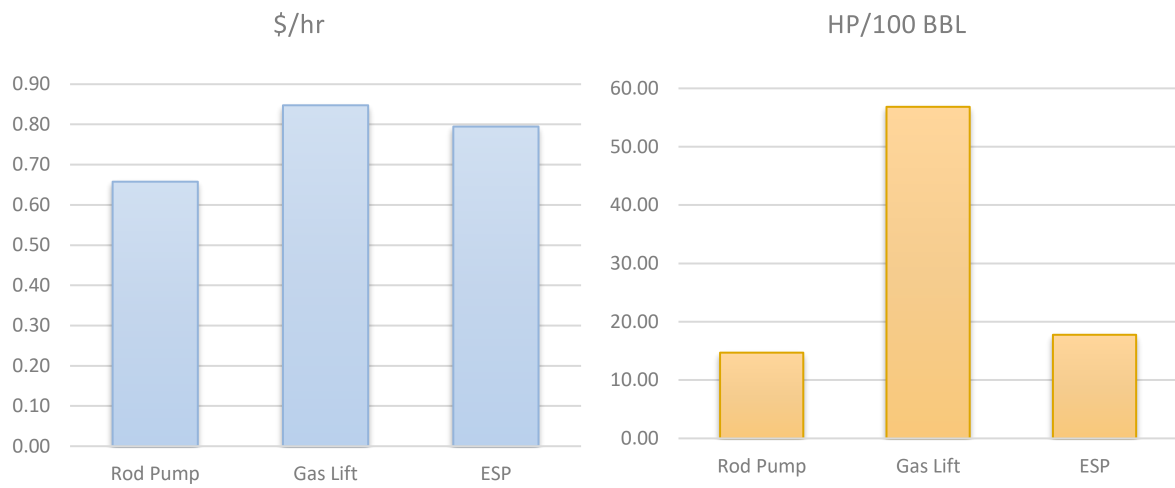

Figure 4-9 Operation cost and horsepower per unit volume comparison

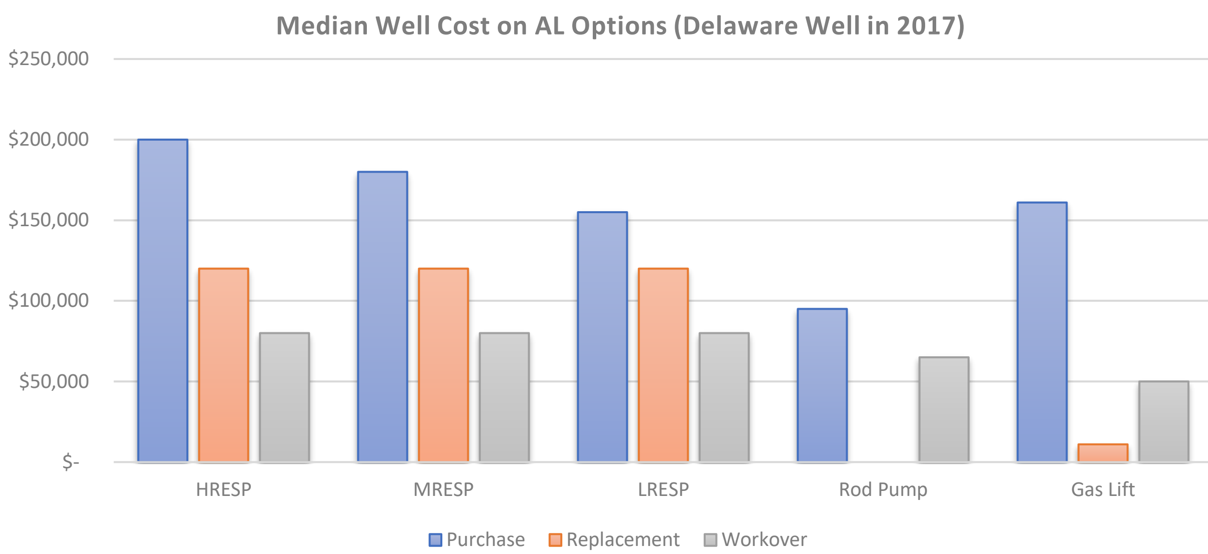

Figure 4-10 Well cost breakdown by artificial lift option

4.2. Separation

Figure 4-11. depicts the separation process as the next operation step in production at the well site after extracting the mixture of oil, gas, and water from the subsurface. Separating the crude from gas and water occurs in a separator tank consisting of a horizontal separator with internal baffling to separate gas, hydrocarbon liquid, and water. Little energy is used. Produced gas goes to gas treatment, oil goes to a stabilizer, and water goes to water treatment. The gas from the separator (consisting of C_1, C_2, H_2S, CO_2, and small amounts of C_3 and heavier) is compressed dehydrated and treated for H_2S removal (may treat for CO_2 removal, if needed). The resulting gas is sent out as a product or reinjected into a reservoir to maintain pressure. The C_3 and C_4 will be either sold or reinjected.

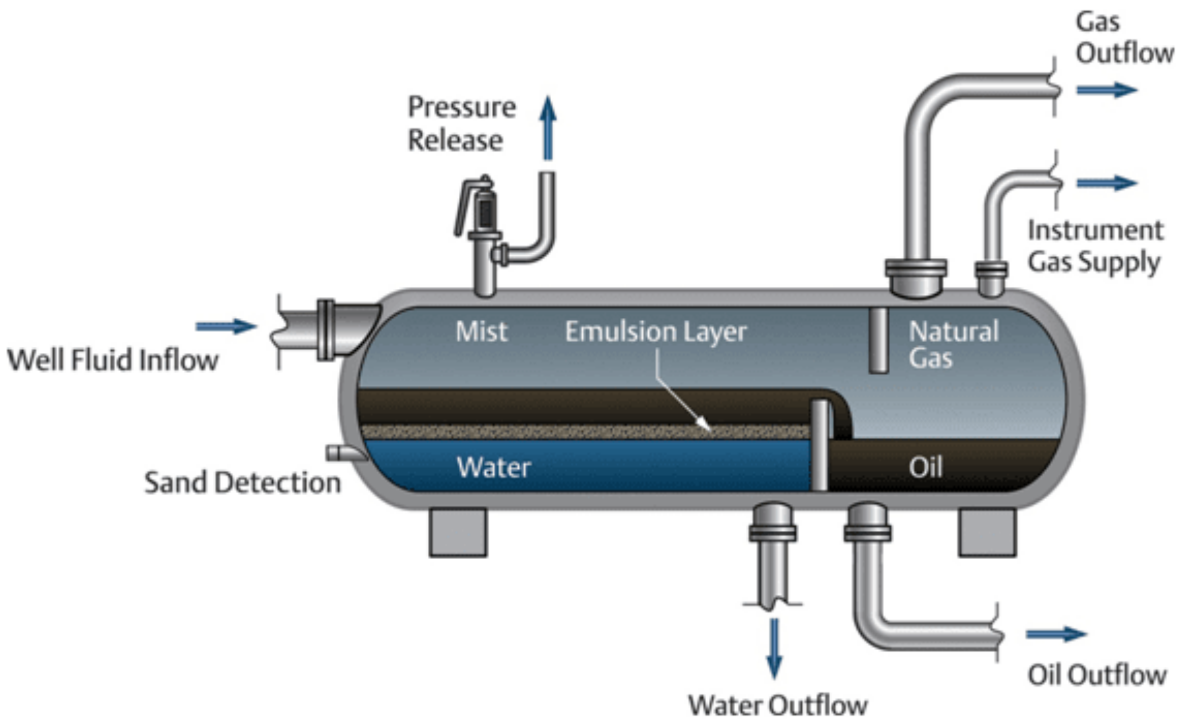

Figure 4-11 Schematic of the separation process (source: Emerson: PID Control in 3 phase oil and gas separation, 2015)

4.3. Heat treatment and stabilization

Heat treatment eliminates low concentrations of water left in crude by applying heat directly to the emulsion fluid. Heat breaks down the water bond to oil, and the oil can move to the next process. The next step is stabilization, where electricity is supplied on-site or imported from the grid. Figure 4-12 is a picture of the stabilization unit.

Crude oil from the separator may contain a small amount of light components (C_1 to C_4) that must be removed before the oil goes to the stock tank. For safety, electric heating supplies reboiler heat instead of direct firing. Crude from the separator is stabilized by removing light components C_3 and C_4 and any remaining C_1 and C_2s. The gas can be reinjected into the reservoir or sold as a product. Both reinjections of water and gas require energy. Water reinjection requires energy and is supplied by an electric motor, while most gas reinjection uses a gas-fired turbine without a grid connection. It is the same as what was mentioned for the gas lift option.

Figure 4-12 Stabilization unit (Source: Schlumberger)

4.4. Load estimate of upstream activity at a well site

Figure 4-13 summarizes load-requirement assumption by type of activities in upstream activity. In the current study, all enhanced oil recovery activity only includes water flooding for vertical wells in the Permian. Hence, it is a relatively small portion and not located in the fastest-growing subbasins. Instead, it is located mainly in the Central Basin Platform. For the vertical wells included in the study area, a generic water flooding process for EOR purposes is included to account for the additional electricity requirement.

Artificial Lift Choice	Additional On-site processing and separation	Water Recycling -	EOR Injection
•Continuous power •15 Hp/100 bbl liquid (oil and water) per day , if using ESP or Rod Pump; •0 hp if using gas lift	•Central tank battery / Separator – 1 Hp/100 bbld (oil and water)	•Only applied to vertical well 4 Hp/100 bbld	•For vertical conventional well 5 HP per 100 bbld water

Figure 4-13 Load-requirement assumption by upstream activity

No carbon dioxide EOR activity is included at this point. For the historical period, CO_2 EOR is not yet a significant portion of the load requirement in the Permian. Still, there is further momentum for future CO_2 EOR given the additional tax credit and market interests as a potential application for carbon capture and use. However, the current application of CO_2 EOR is mainly targeted at vertical wells; the upside of the activity is also limited because most of the growth remains to be with horizontal wells.

Figure 4-14 aggregates load estimates of upstream activity over time from 2012 through 2020. The artificial lift activity takes most of the load requirement for the upstream activity. Figure 4-15 is a snapshot of the load requirement across counties for September 2019.

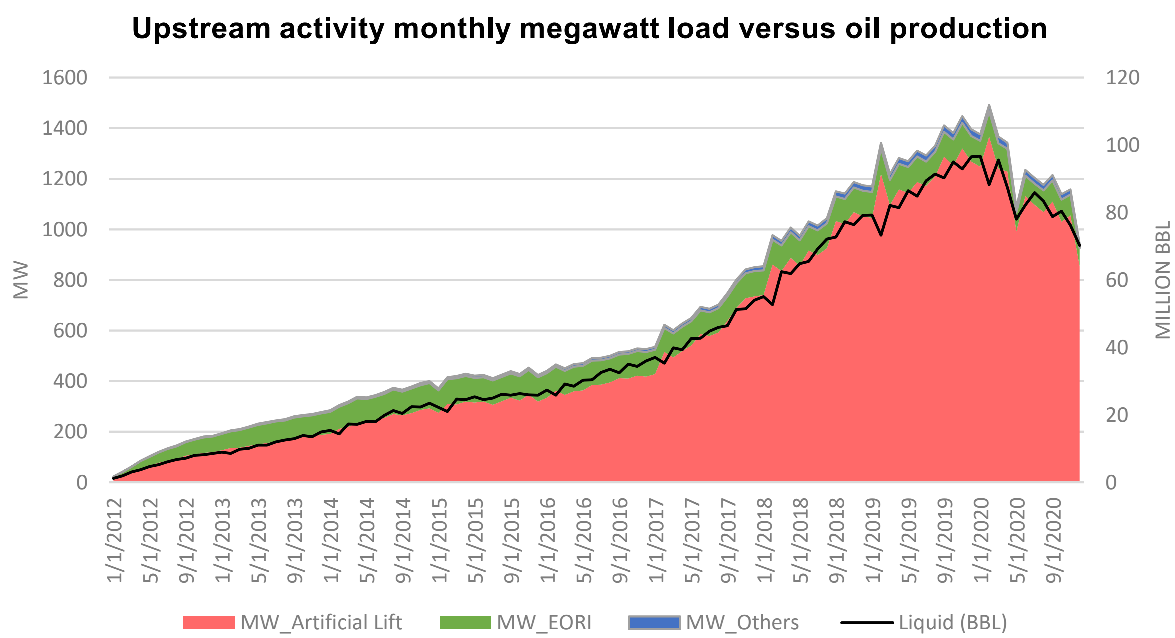

Figure 4-14 Historical load by upstream activity and oil production

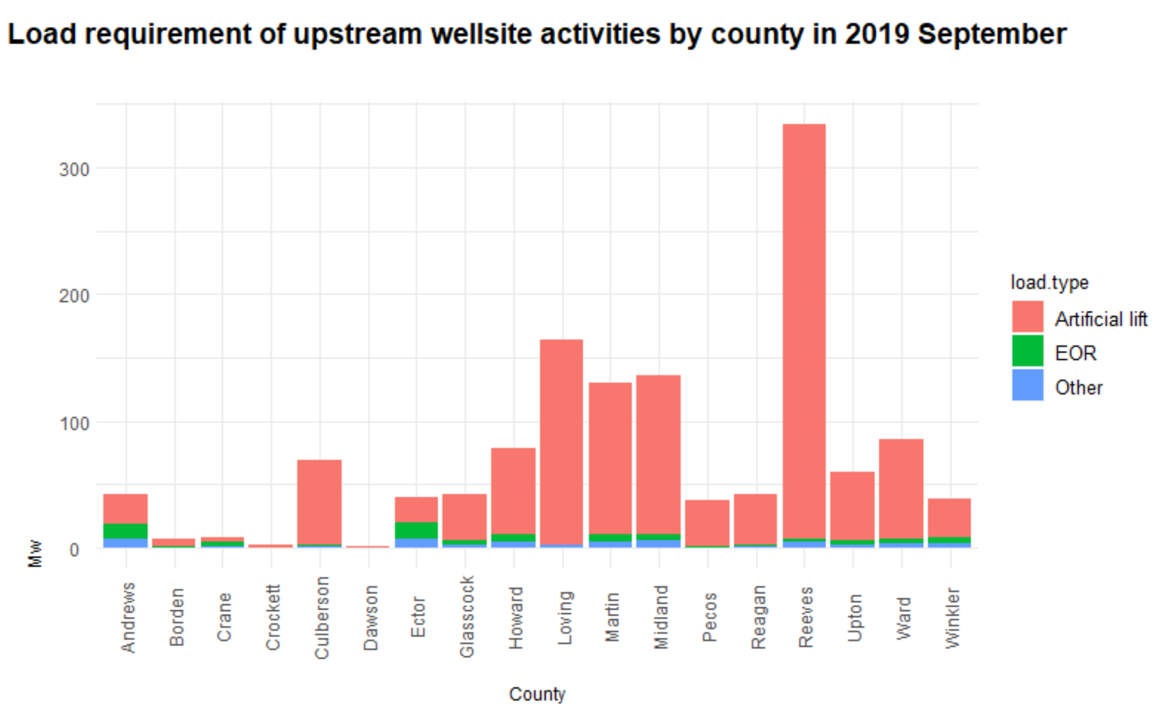

Figure 4-15 Load by upstream activity by county for September 2019

Furthermore, during the interview, operators mentioned that the decision to link to the grid includes the following factors:

Distance to the grid is the first important factor. If the sites are not too remote, all operators agree that a grid connection is preferred for their production operation. However, there is a long wait for grid connection in West Texas, with wellhead sites usually located in the field. Since the process itself may take a couple of years, the operators often find it difficult to accurately submit their estimates of load demand at the time of application, knowing that the actual grid connection would only be realized in a few years.

Therefore, there is a tendency to stay optimistic about the load estimate as the risk of a low load is usually higher for the operators themselves. Some of the operators interviewed are willing to build their distribution line to the grid if that could lead to shorter waiting times if the distribution line is only a couple of miles: self-build distribution lines take 1-2 weeks on the short side, compared to a couple of months or longer with local coop.

The reliability of the grid is the second factor. Operators often mentioned concerns regarding the reliability of the grid connection, especially when it comes to upstream lifting activities. Oil and gas operators' continuous load requirements define a lower tolerance level than ERCOT's system minimum threshold for blackout reporting. Therefore, brief fluctuation of power on the grid could cause interruptions on the operation side. Sometimes, a local service interruption or power outage event would stop the lifting process and cause additional restarting trouble.

4.5. Saltwater disposal sites

The next section discusses the activity involving the transportation and disposal of produced water. There are two interconnecting but separate water challenges faced by increasing Permian production. Large volumes of water are required for hydraulic fracturing upfront during well completion, and, second, limitations to disposal of produced water in these low-permeability unconventional-shale reservoirs. While hydraulic fracturing water demands are an issue, there is also increased concern about the large volumes of produced water.

Figure 4-16 demonstrates the amount of produced water from production relative to hydrocarbon production out of the Texas portion of the Permian Basin[3], about 4-5 parts of water per one hydrocarbon.

There are two separate possible routes for produced water in the Permian today: reinjected back to the well for enhanced oil recovery (EOR) purposes for conventional vertical wells or transferred to saltwater disposal to reinject into a different reservoir. The following Figure 4-17 describes the value chain of water activities. The activities that consume significant energy are marked with a red border here.

Water out of the wells may need to be treated. Depending on the water quality and treatment requirement, energy consumption varies. Produced water is often brackish and contains residual oil, and it must be treated before disposal to remove salts and oil. Water that will be reinjected either produced water or water brought in, must be filtered to remove particulates and deaerated.

[3] BOE - A barrel of oil equivalent (42 gallons or 6000 cubic feet of natural gas)

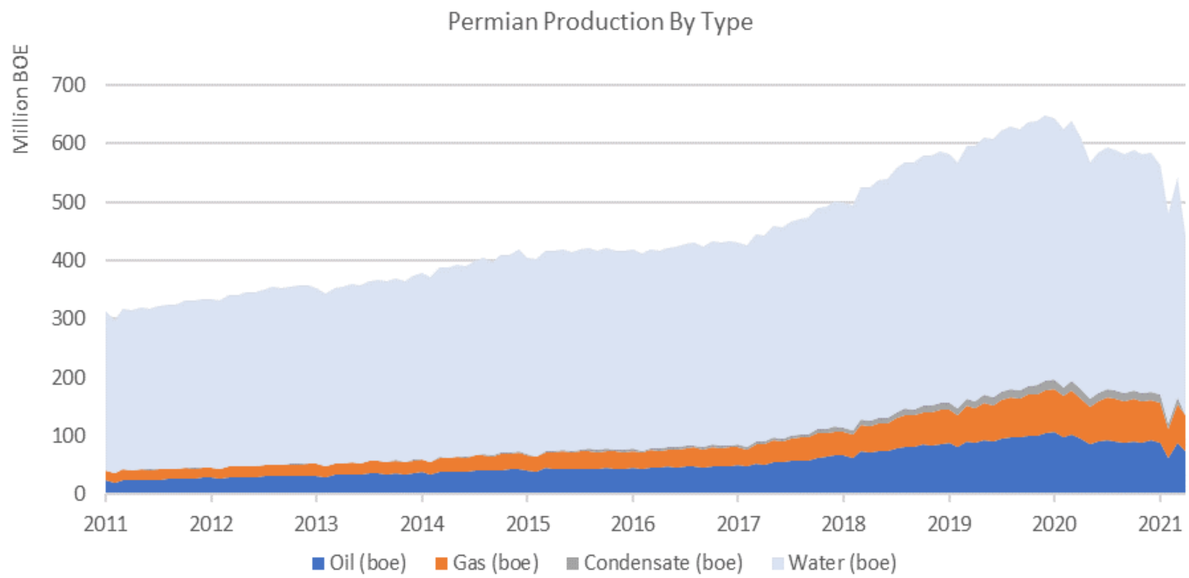

Figure 4-16 Historical Permian (Texas) production by type

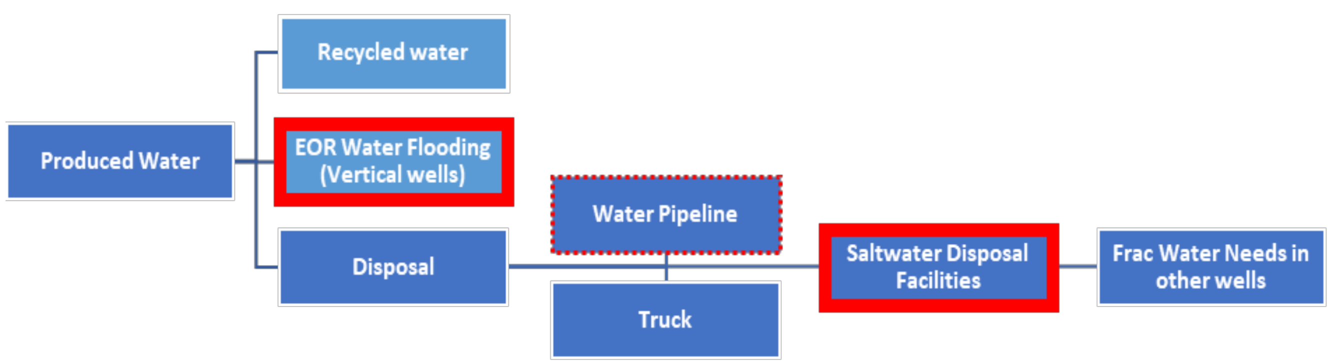

Figure 4-17 Water value chain

The major energy use in water treatment is for deaeration. Filtration and bacteria removal use filters to remove particulates, and energy for filtration is based on pumping for 150 psi, which adds a small amount of overall energy. There is an assumption of 5% water loss through vaporization for the deaeration process. Energy is provided through electric heating. Desalination is needed to meet the quality of water standards for reinjection or disposal. Water treatment was assumed to be done by reverse osmosis or vacuum evaporation. Energy is primarily based on pumping, requiring 0.009 KWH/per gallon of water.

Besides the water used directly for EOR and recycling at the well pads, the rest of the water is hazardous if left on the ground. Per the Environmental Protection Agency (EPA) policy, produced water needs to be treated as nonenvironmentally damaging and reinjected through saltwater disposal wells (SWD) in a designated reservoir. Hence, the produced water is transported via pipeline or trucking in the Permian.

Saltwater disposal facilities (SWD) belong to EPA Class II injection wells, which are mandated to have multiple layers of projection in design to protect the environment. Figure 4-18 demonstrates that the facility includes the following activities: unload, filtration, separation, treatment, tank (water and oil) pumps, and disposal. Residual oil separated from saltwater is sold back to the market as skim oil. Saltwater can be recycled and used as water for fracking near well pads in certain situations.

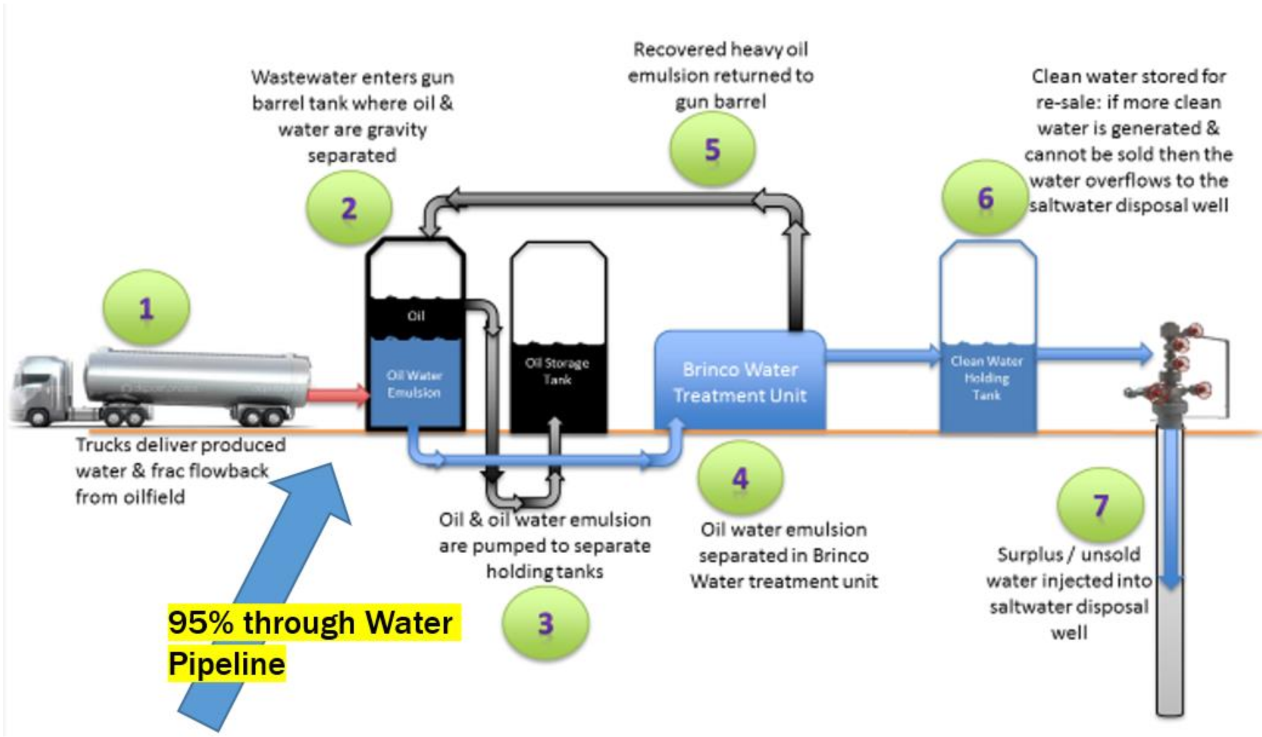

Figure 4-18 Saltwater disposal facility (source: Kleanwater)

SWD facilities require continuous power and are usually connected to grid power. The methodology of calculating water pumped back into the wells is a function of well depth, flow rate, and pump efficiency. Figure 4-19 shows a map of all SWD wells dated 2012 or later in the study area.

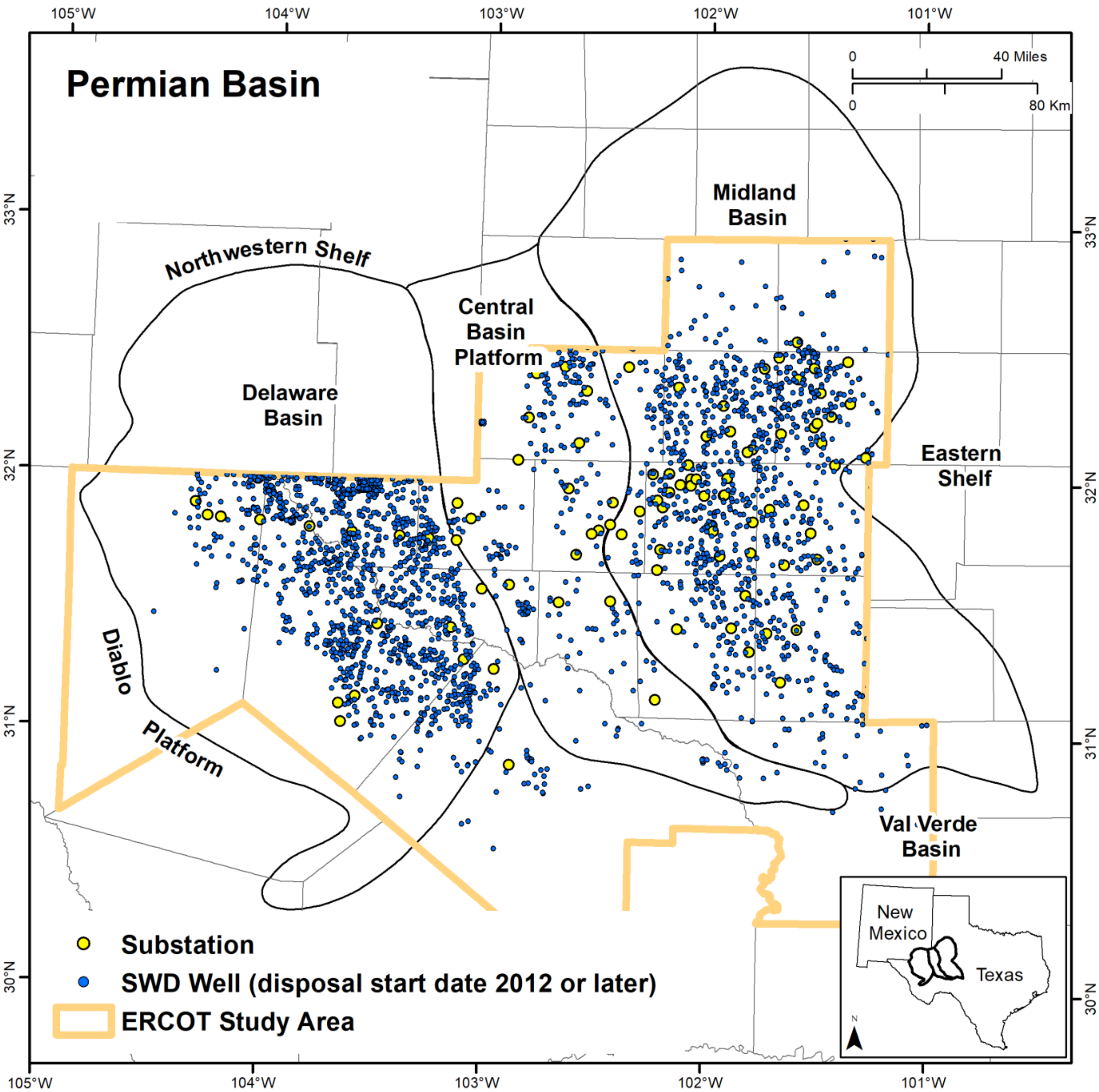

Figure 4-19 SWD facilities in the ERCOT study area

The current study has historical data on water injection volume by SWD facilities in the Permian, which could provide a more detailed calculation of historical power requirements per site. Figures 4-20 and 4-21 show the aggregated water injection volume and its power requirement for SWD facilities from 2012 to 2020.

Most SWD facilities rely on local grid connections; hence, most SWD facilities' load is expected to be on electricity. Based on the county-level estimate, Reeves and Loving County, with the fastest-growing number of SWD facilities, also have the highest load as of September 2019. Figure 4-22 shows the estimated SWD load requirement by county.

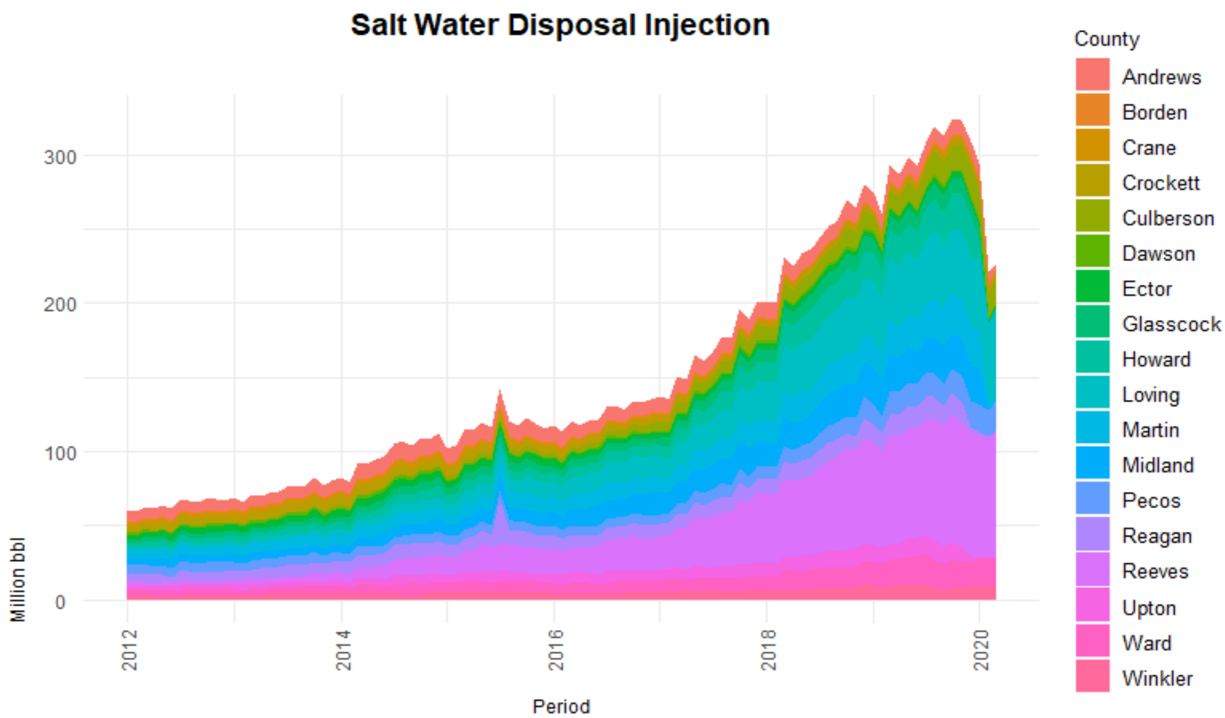

Figure 4-20 Saltwater disposal injection

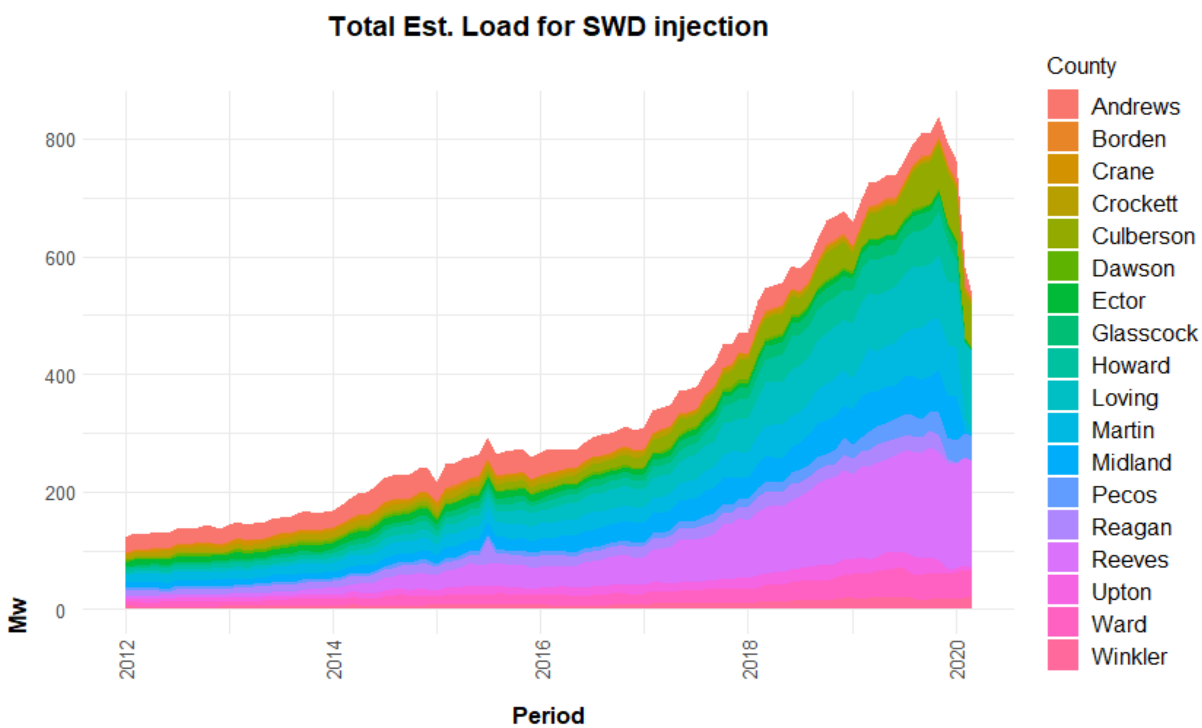

Figure 4-21 Total est. load for SWD injection

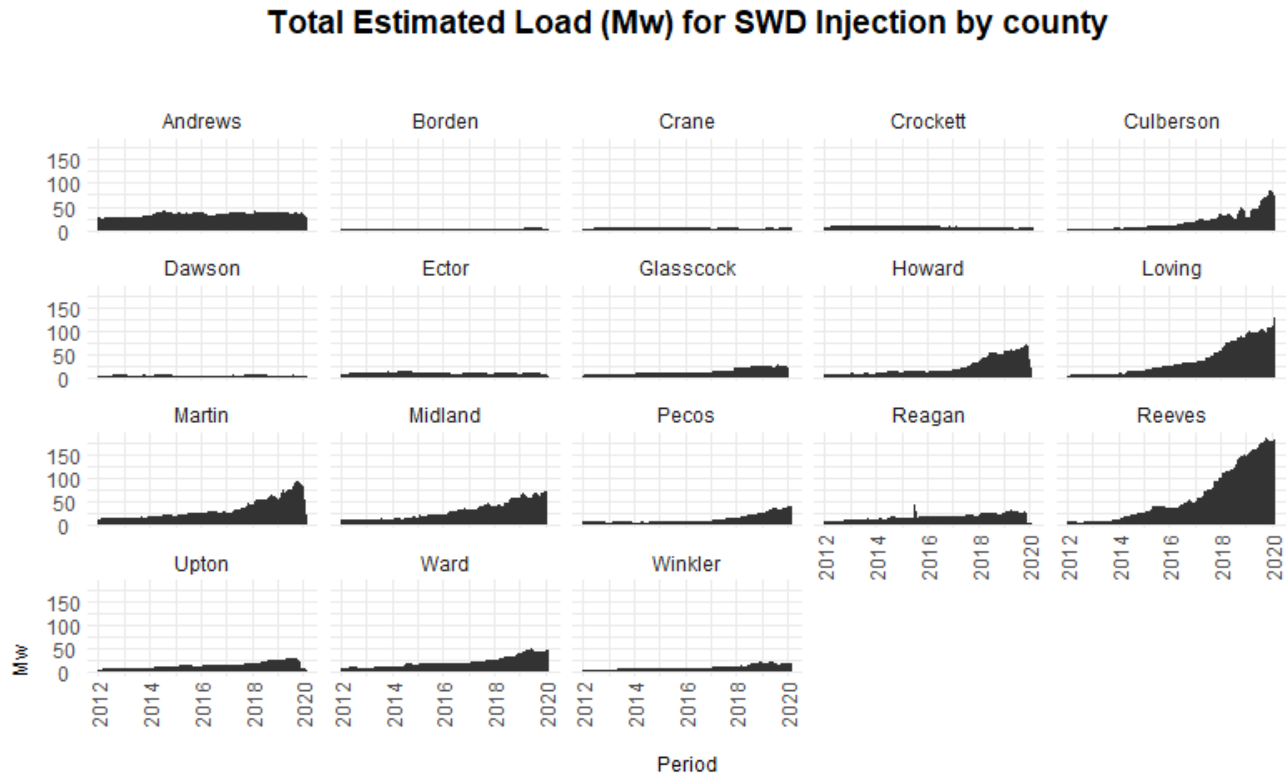

Figure 4-22 Total estimated load for SWD injection by county

There are two key assumptions based on historical observation and data for the future load forecast.

First, the future SWD load is projected based on forecasted produced water production from producing wells, assuming that the produced water is largely transported to a nearby SWD facility by either truck or pipeline. The SWD facilities' depth for future wells is like the historical average in the county and has similar pump efficiency and operation parameters.

Second, the location of the future SWD load is projected to be about 3 miles around the producing wells, based on the historical average distance from a producing well to the closest two SWD facilities in the study area, shown in Figure 4-23. Water is heavy to transport; therefore, producers have the economic incentive to ship the produced water to the closest facilities for disposal if possible. This chart shows the closest SWD facility to a producing well as NEAR_RANK = 1, and the second closest SWD facility to a producing well is shown as NEAR_RANK = 2.

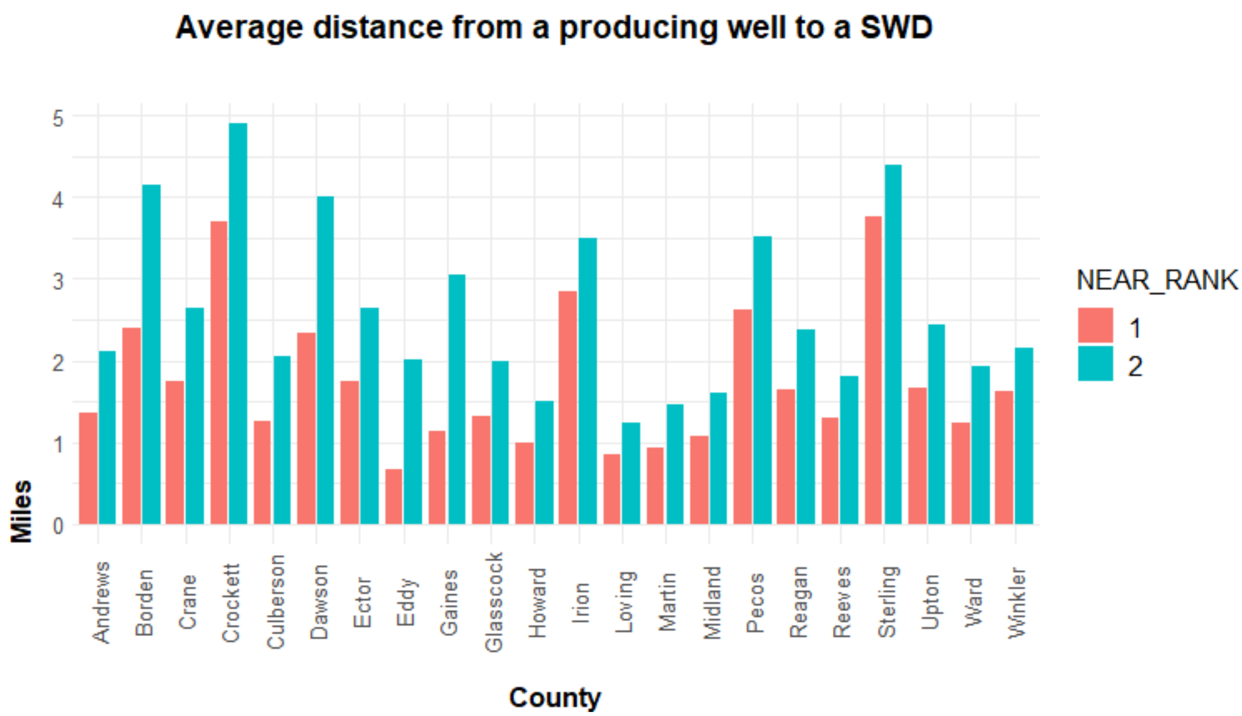

Figure 4-23 Distance from a producing well to an SWD by county

Chapter 5. Assessment of the load requirement for midstream activities

5.1. Definition of midstream and overview of midstream facilities

Besides produced water, which is covered as part of the disposal activities from the previous chapter, the rest of the produced oil and gas are transported, processed, refined, and treated for downstream markets. The infrastructure and processes involved between the well site to the market-ready commodity are considered midstream activities. Midstream activities serve an important role in the value chain, helping to transport raw products from the field, transforming these products into usable and marketable products, and connecting upstream production to downstream deliveries to end-users.

This chapter discusses the midstream activities of transporting oil, gas, and liquids from wells via a gathering pipeline system to treatment and processing. The flow chart below in Figure 5-1 (same as Figure 4-1) demonstrates the parallel while interconnecting processes of transporting natural gas, liquids, and oil through midstream activities.

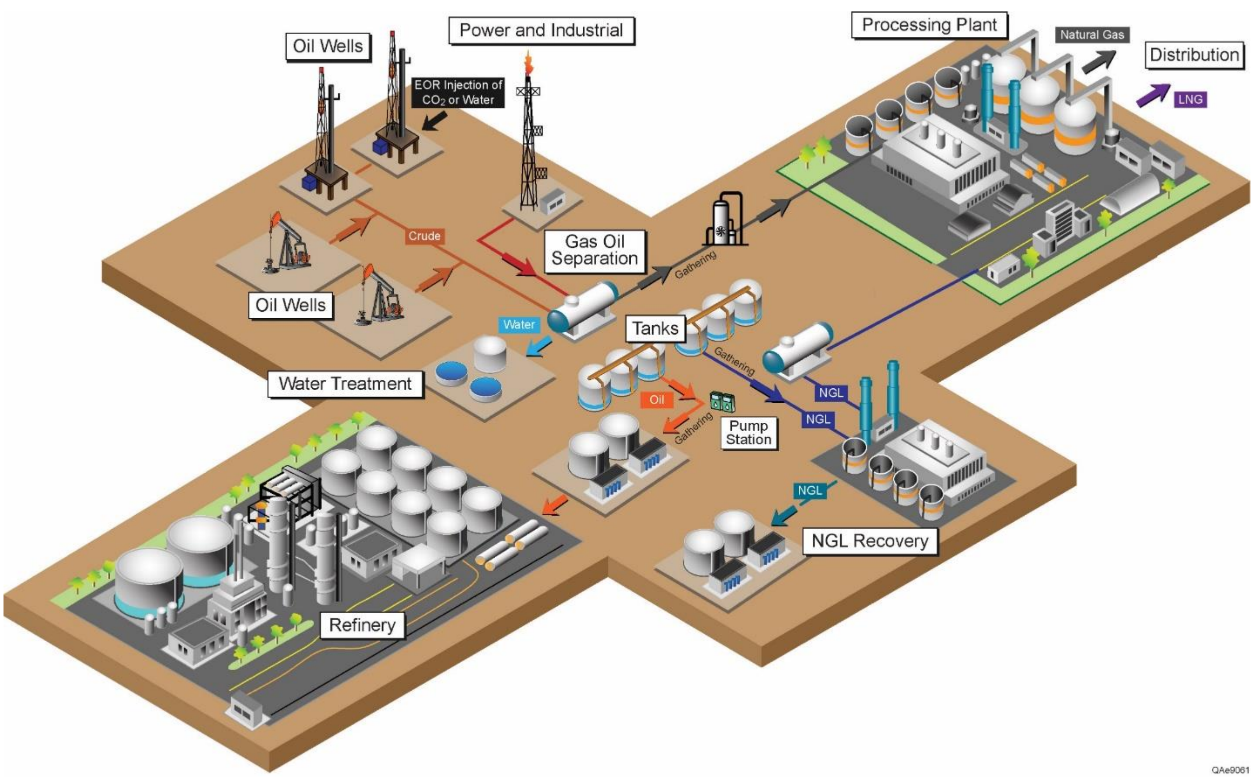

Figure 5-1 Oil and gas activity schematic

Due to the different processing requirements, the oil and gas from the field go through different and parallel midstream activities. When extracted from the field, there is a mixture of oil and gas (and liquids). Separate oil, gas, and natural gas liquids flow to the respective storage tanks after initial measurement and some removal of waste product. At this stage, the products are not yet up to standard for the market. Midstream activities take these raw products and transport them into a more centralized processing plant for natural gas or refineries for oil.

Figure 5-2 plots the natural gas pipeline in the Permian Basin for the study area categorized by three diameter groupings here: 3-6 inch diameter pipelines, 6-12 inch diameter pipelines, and any pipelines greater than 12 inches. Most gathering system lines are smaller diameter pipelines under 12 inches, while main transportation lines are greater than

12 inches. Figure 5-2 summarizes the total mileage of natural gas, crude, and natural gas liquids (NGL) pipelines by diameters by county in the study area. Note that there are many more natural pipelines in terms of mileage than oil and NGL. There are facilities along the gathering pipelines to transport oil, gas, and NGL across distances from well sites to processing plants.

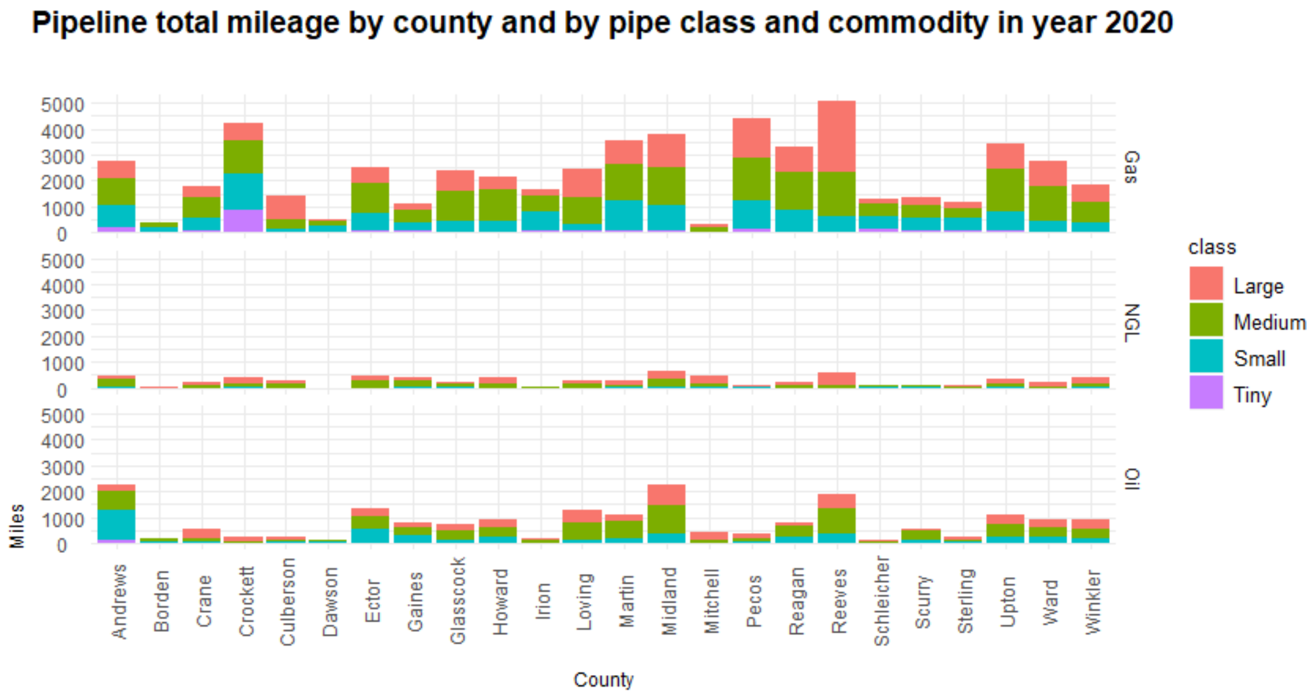

Figure 5-2 Pipeline mileage by county and by pipeline class and commodity

Figure 5-3 describes the gathering processes of oil, gas and NGL as three concurrent processes in the field.

The oil leaving the field is called crude oil, as it must be further refined into various marketable products. It often goes through the oil gathering system that collects crude oil from well sites and transports cumulative volumes from wells into a refinery.

Pump stations along the gathering line or pipeline are vital in moving crude oil or NGLs (and refined petroleum products) through the gathering and transportation pipeline system. Pump stations are facilities along a pipeline that contains pumps to maintain the desired pressure and flow of liquid product through the pipeline. In general, pump stations contain one or more electrically-driven pumping units. They are strategically located to boost internal pipeline pressure and flow within safe operating limits of the pretested pipeline. Pump stations then move the crude oil through the pipeline to the next station or its final market destination. Typically, pump stations are situated 40-60 miles apart; however, their exact location is determined by various factors, including engineering design, terrain, power availability, and delivery needs.

The gathering system supported by pump stations transfers crude oil to oil refineries, large facilities that process crude oil into refined petroleum products. The refined petroleum products are then transferred through product terminals to the next stage of the transportation, either trucks or pipelines, to downstream users.

The gathering system of natural gas is similar to crude oil. It is designed to take unprocessed natural gas from well sties to processing plants where natural gas is processed and ready for transport to downstream users. The natural gas produced and gathered from the wellsite via the gathering system is called wet gas as it includes extra water, wastes, and more NGLs (light hydrocarbons) products.

Compressor stations are set up along the gathering pipeline to provide power to transport the wet gas. Compressor stations are used for almost every natural gas value chain stage, including gathering, transport, processing, storage, and distribution. Based on 2018 data, the US has approximately 1,700 mainline natural gas pipeline compressor stations with 5,000-7,000 compressors and 15,000 plus smaller compressor machines in gas gathering systems.

A gathering compressor station receives natural gas from area well sites via pipeline or another compressor station. The received gas is compressed and sent down the pipeline for processing at a natural gas plant or another compressor station. Sometimes, a compressor station also includes sulfur removal and NGL removal processes, but the volume of NGL collected here is often small.

Natural gas liquids refer to the light hydrocarbons that are marketable products from the oil and gas stream. The gathering of NGL occurs in multiple stages of the gathering and processing activities: NGL can be gathered sometime after separation at the well site or from the compressor station with NGL removal (often, this is a small volume).

Most NGL is extracted from the gas stream at the natural gas (processing) plants, which use cryogenic processes that drop condense NGLs. Natural gas plants typically have compression on-site, but it is not required. Residue gas (natural gas, mainly methane, with a substantial quantity of the NGLs removed) and NGLs leave the facility in separate pipelines.

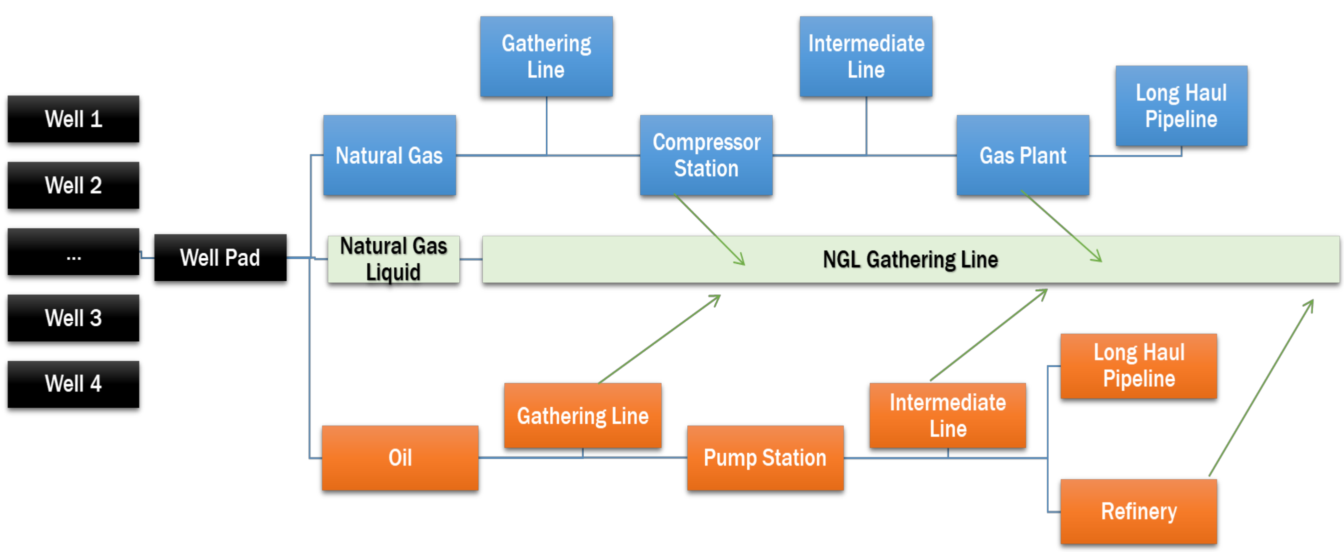

Figure 5-3 Gathering transportation system

5.2. Gas gathering lines

Figure 5-4 presents a map of natural gas pipelines in the ERCOT study area, including all categories and sizes of the pipeline. In this section, we first discuss the estimation of load for gas gathering lines.

Like calculating load for transporting water, gathering pipeline load estimates follows similar engineering principles. It requires assumptions on flow rate, traveled distance, the distance of pipe, and gravity of fluid and gas. This section covers the methodology and findings in estimating the power requirement for gathering systems.

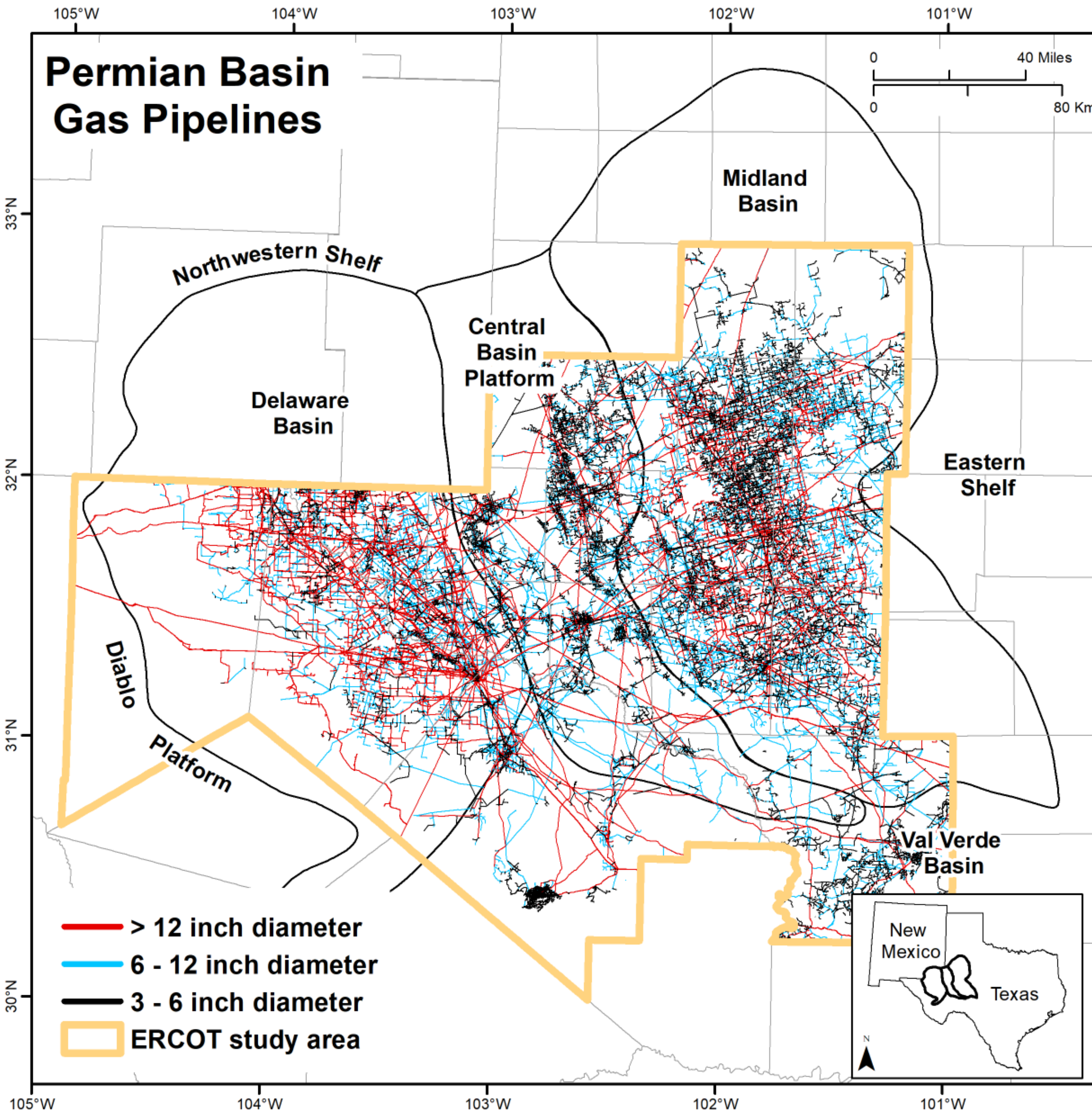

Figure 5-4 Gas pipeline in the ERCOT study area

Due to the lack of field data on compressor stations and gathering system flows, an alternative methodology would estimate the total required energy for transporting natural gas from wellheads to processing plants without knowing the exact location of the gathering lines or their compressor stations. This methodology only uses the available data on gathering systems, including the total mileage of local gathering lines and intermediate gathering lines on the county level, along with knowledge of the total volume to be transported and the number of wells per county.

Figure 5-5 demonstrates the flow of natural gas through the gathering system from wellheads via flowlines gathering lines to the gas processing plant. There are compressor stations between each transportation step to maintain gas pressure and flow speed. The compressor stations are where the energy is consumed to compress gas through pumps powered by turbines or electricity grid connections.

There are two key assumptions about the grouping of the wells on gathering lines that would impact the power requirements: the number of vertical wells per gathering group and the number of groups per intermediate gathering point. For vertical wells, this study uses ten vertical wells per group and one well pad for horizontal wells per group. There are about 2-4 wells per well pad in the Permian based on historical data.

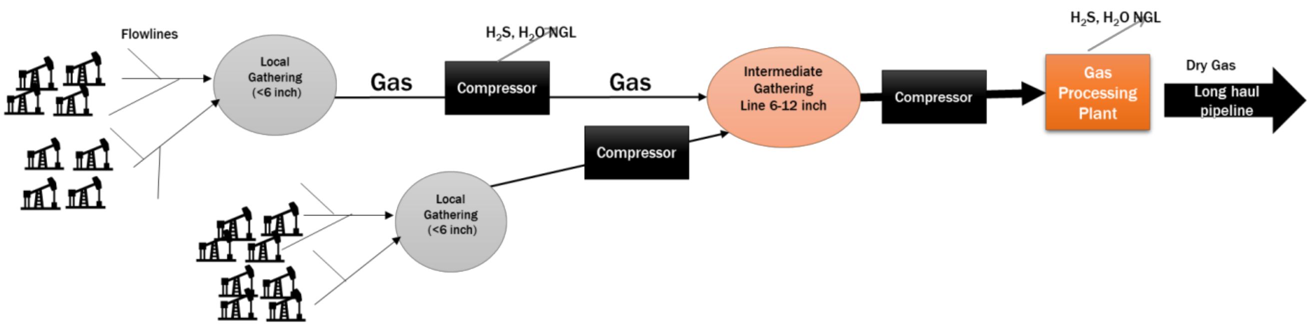

Figure 5-5 Natural gas gathering system structure

With the knowledge of mileage by pipeline class (by diameter) per county, a hierarchical system gathering system is used to demonstrate and estimate flow rate per pipeline and load requirement. Gathering lines are grouped further at an intermediate point, usually with additional compression in the field before reaching the processing plant. The average number of groupings is assumed to be somewhere between 2-4 gathering lines per group of intermediate lines in the field. This assumption is based on two sources of reference:

1. IHS Markit Study published in 2020
2. Based on the TCEQ database of 2020 reporting, there are 260 compressor stations reported in the study area. Assuming these are larger compressor stations required to report emissions, it is plausible that this would be a good approximation of the intermediate compressor stations in the area.

Based on the data on well pads and grouping in this current study, on average, 2.4 lines are grouped into one intermediate line across counties, while each county has a different grouping number (rounded to an integer). The next step is to calculate the number of local gathering points and intermediate gathering points based on the grouping assumptions and existing wells by type. Combined with the average production rate per well by type (vertical versus horizontal), we can calculate the flow rate of each gathering line and the mileage per gathering line type.

With the assumptions of gas production rate per well and grouping structure of the gathering system, the next step is to estimate the approximate flow rate per gathering line from well to intermediate gathering point and from intermediate gathering points to gas processing plants. The gathering line from wells to the intermediate point is assumed to have a 3-6 inches diameter, while the intermediate pipeline is 6-12 inches.

Given the diameter class of the pipeline, the energy requirements to transport gas are calculated based on the relation between the flow rate (volume) and the distance traveled along the pipeline. The power requirement via different diameter pipelines and traveled distance is calculated based on the interpolation of the energy requirement matrix. See the matrix details in Appendix.

The methodology flowchart with key assumptions is listed in Figure 5-6. Figure 5-7 demonstrates that the power requirement curve for an 8-inch pipeline is a function of flow rate (volume in mcf per day) versus traveled distance. The further the distance, the higher the required power, while the relationship is not linear.

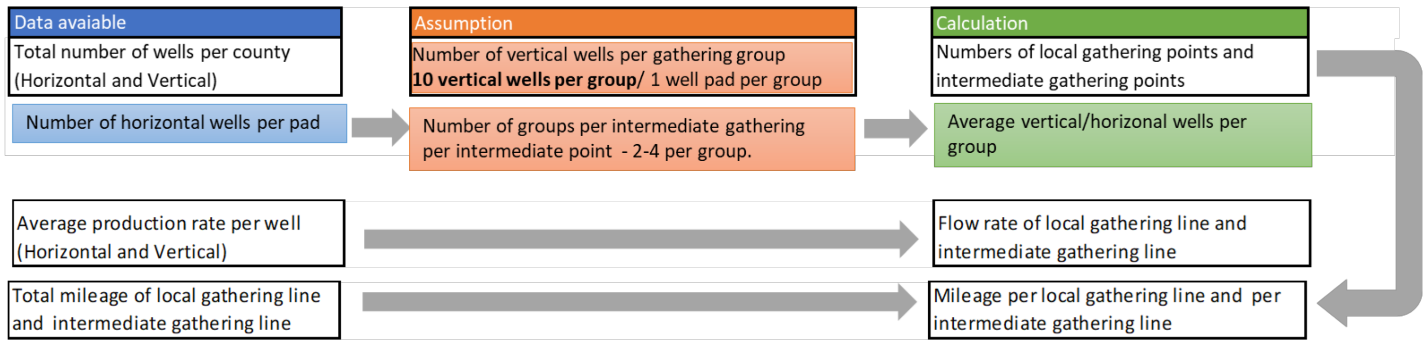

Figure 5-6 Gathering line load-requirement assumptions

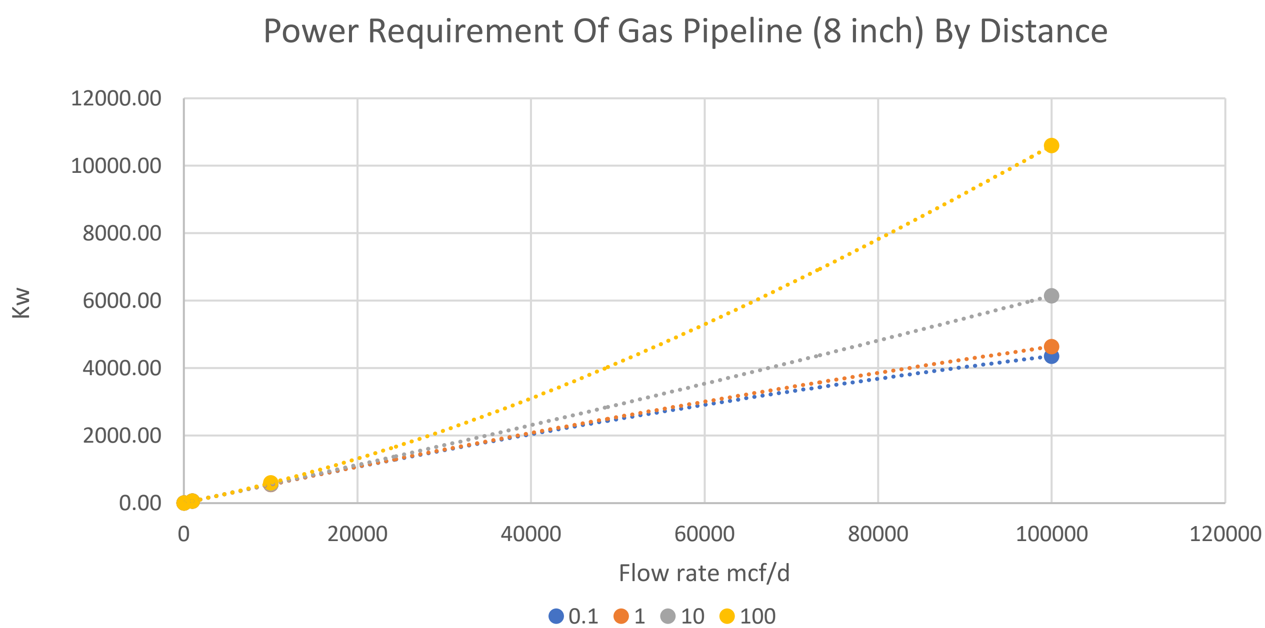

Figure 5-7 Power requirement of gas pipeline by distance and flow rate

In 2019, the average local gathering line by county was 0.4 miles, and the average intermediate gathering line was 6.1 miles. Figures 5-8 and 5-9 summarize the number of wells and gathering system mileage for the year 2019 and the power requirement estimation by county for the year 2019. Assume that the mileage of gathering and intermediate gathering systems increases as the well numbers increase. In 2019, there is above 1,080 **MW** in total for gas midstream covering over 33,000 wells and almost 10 Bcfd gas.

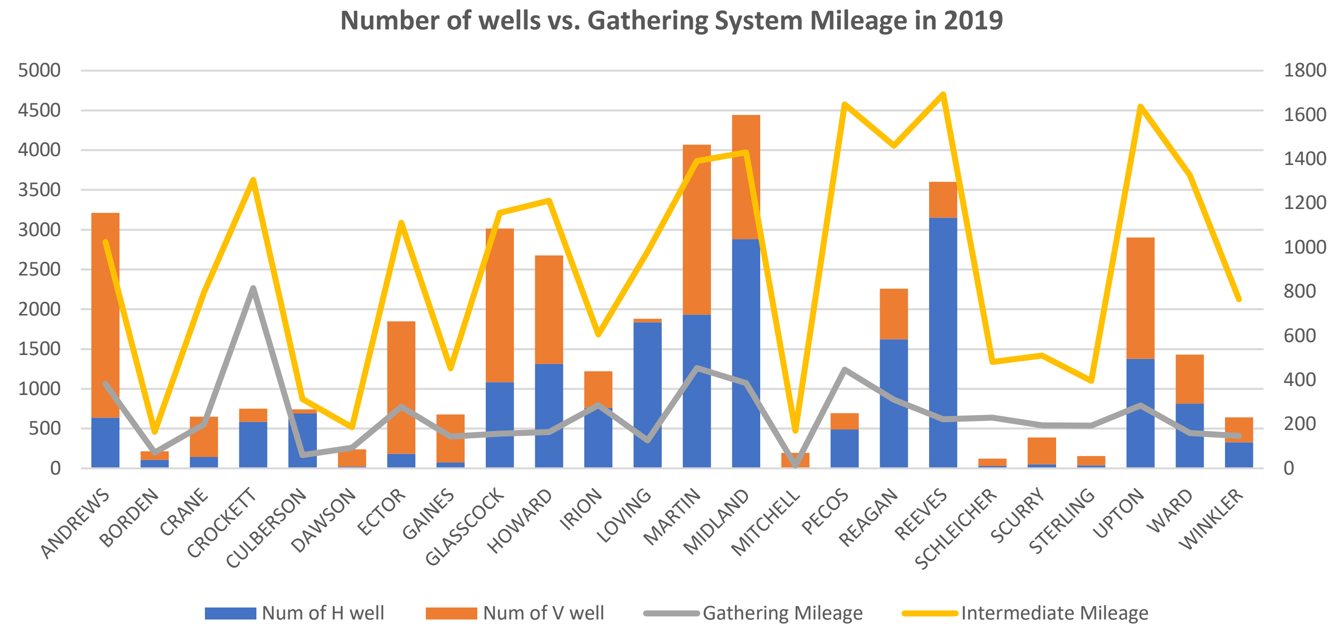

Figure 5-8 Number of wells and gathering line mileage by county

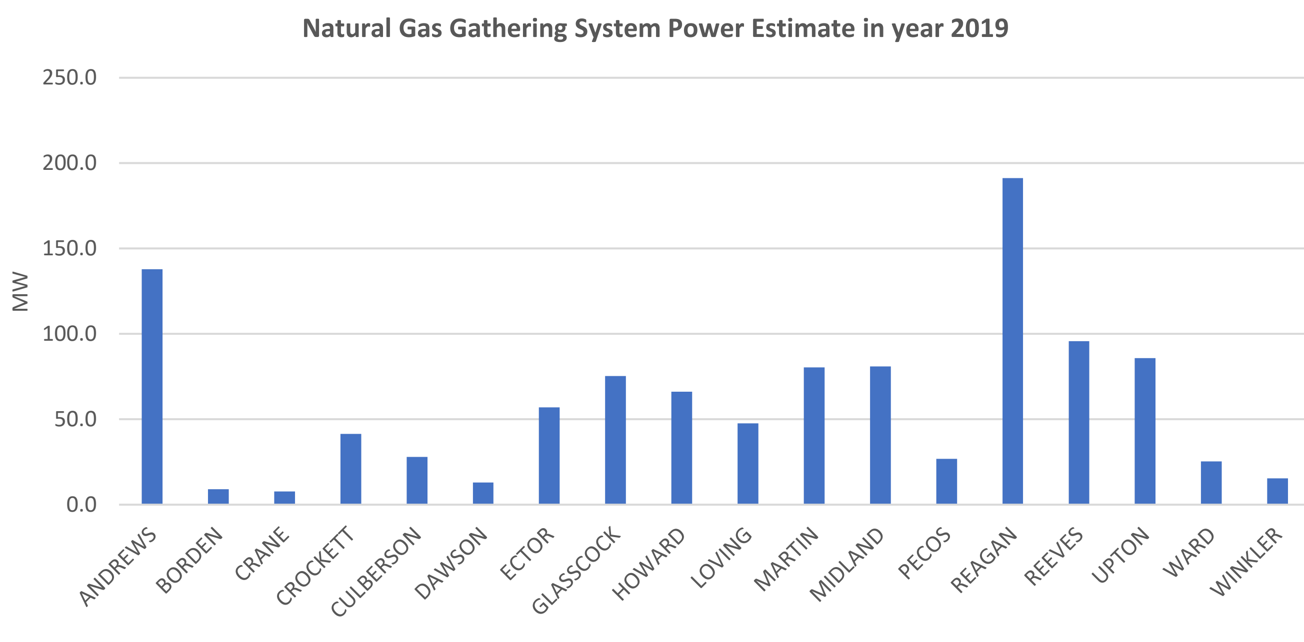

Figure 5-9 Gathering system total power requirement estimate

Note that the power requirement discussed here is the total estimated power required for the operations. Depending on the type of activity and product, the power supply source differs. Hence, not all the power requirements would be from electricity from the grid. Currently, most compressors (about 90% per input from operators and midstream companies) are not powered by the grid. That would seem to be a relief from the concern of uncertainties in our estimation. However, gathering and processing activities represent a major source of emissions for the gas value chain, about 15% of natural gas system methane emissions based on the Greenhouse Gas Reporting Program by the EPA.

Starting in 2016, the EPA started requiring major emission sources with annual emissions greater than 25,000 metric tons of direct GHG equivalence to report annual emissions to the EPA.

Therefore, the choice of electricity supply for compressor stations is in transition, supported by the technical interview from TCEQ, upstream operators, and midstream pipeline companies. Although there is no sufficient field data to estimate the exact level of electrification for compression in the field, it is important to track and monitor compressor station conversion to electricity. There could be a rapid increase of a significant grid load for gathering systems and compressor stations due to the efforts in environmental, society, and governance commitment by operators in the Permian.

Figure 5-10 shows the average distance across each county included in this study. This provides a reference of the possible load impact on gathering relative to the well location. On average, across all counties in this study, the distance to the closest substation is around six miles (NEAR_RANK =1) while the second closest (NEAR_RANK=2) is eight miles, and this is translated as there is a six to eight miles radius of load impact occurring around the producing well.

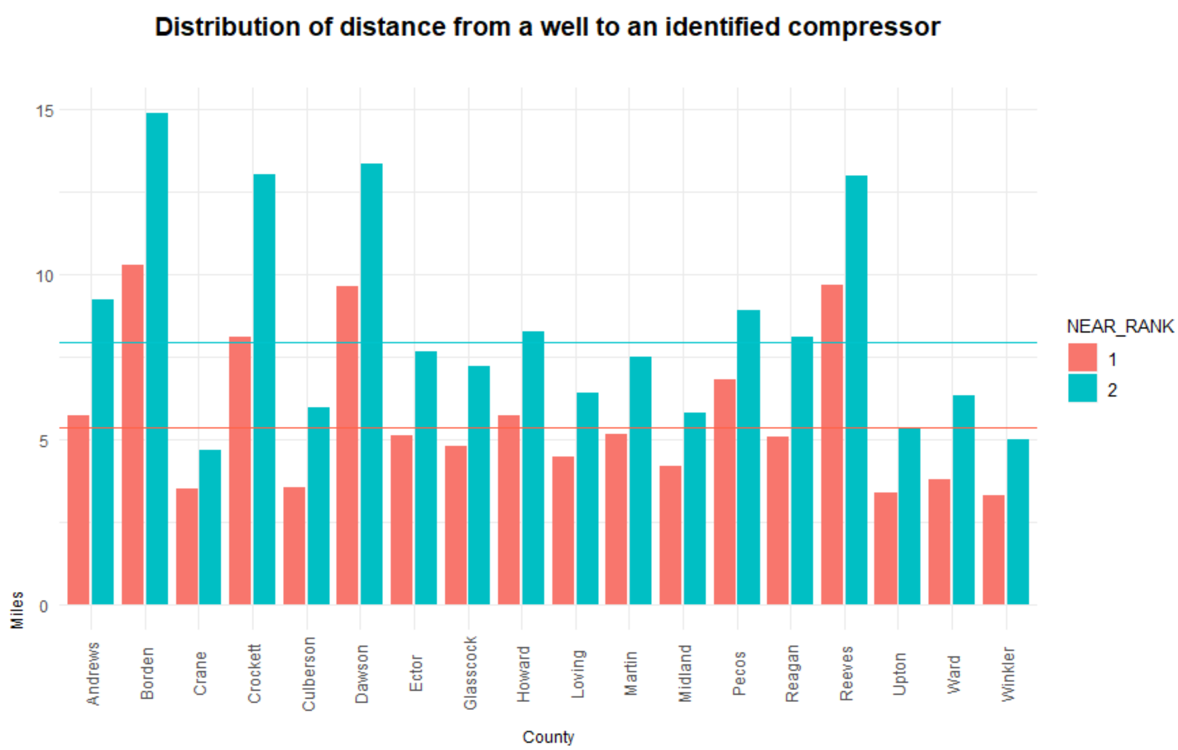

Figure 5-10 Distance from a producing well to a nearby station

5.3. Oil and NGL gathering lines

Figure 5-11 shows the map of oil pipelines in the Permian Basin and oil refineries. Oil gathering system estimation is like gas. It shares the same grouping assumptions of gathering systems in oil versus gas in the current study. Appendix A represents the power requirement matrix for the oil pipeline.

The electricity required to transport oil is much less than gas because it requires less compression. Figure 5-12 summarizes the county's total MW requirement for oil gathering systems in 2019. Pump stations require continuous power and rely mainly on grid power. Booster pump stations are the equivalent to the gas compressor station, and booster pump stations increase the oil pressure received through one pipeline to the next station or refinery. There is usually a 375-400 to 1 ratio of wells to pump stations in literature. That would require around 100 pump stations in the

Permian, and in the TCEQ database, there are only 55 stations accounted for in total.

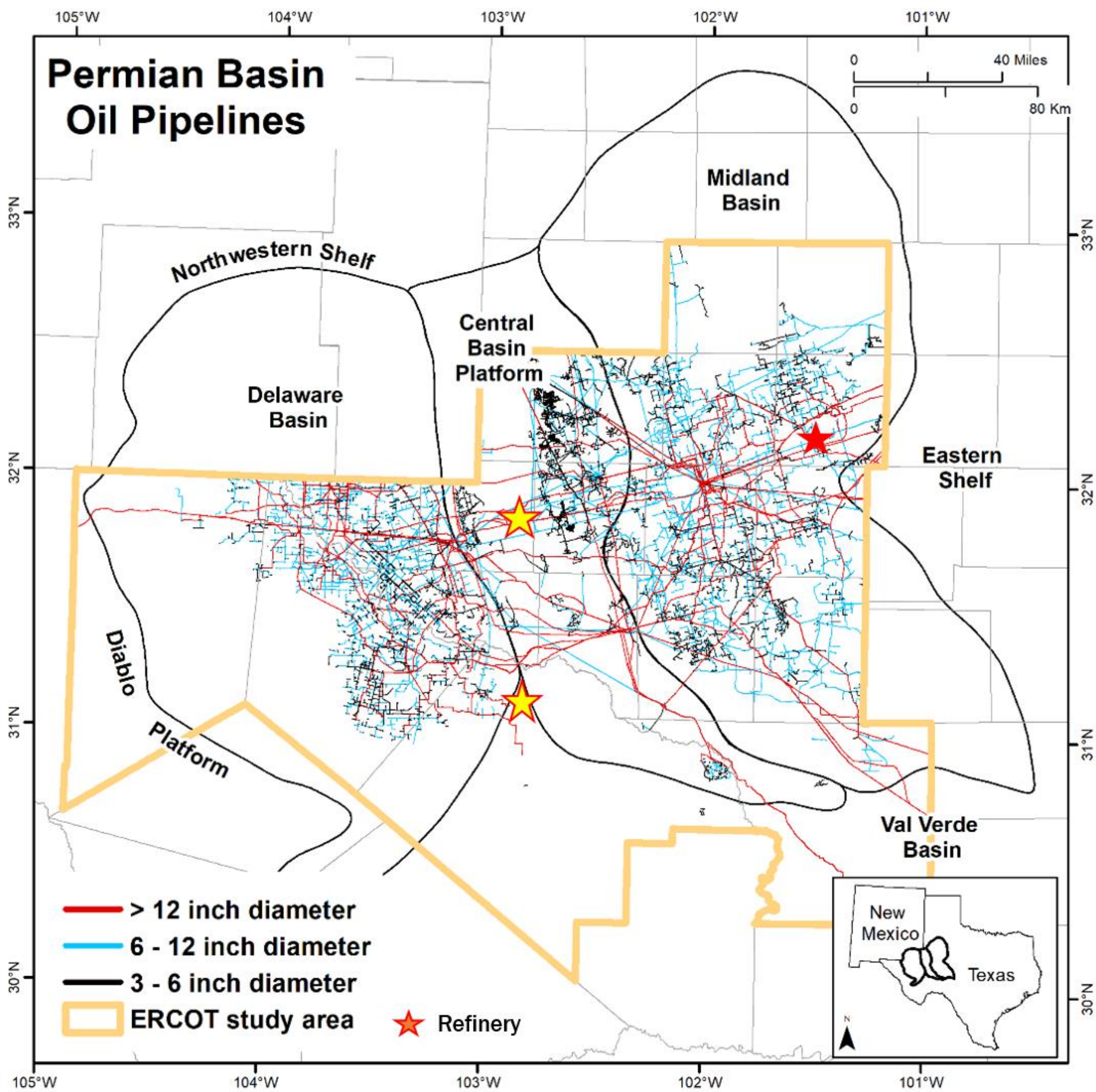

Figure 5-11 Oil pipeline and refineries in Permian Basin ERCOT study area

Similarly, the distance from a producing well to the closest pumping station is also calculated in Figure 5-13, where 1 indicates the closest pumping station (NEAR_RANK = 1) and 2 indicates the second closest pumping station (NEAR_RANK =2). Based on the available data, we could see that the pump stations are generally located at least two times further from the compressor stations. It makes sense because the energy required to pump and transport oil is only a fraction of what is required for natural gas. Again, this average distance serves as the basis of the load impact radius of gathering oil from the producing well.

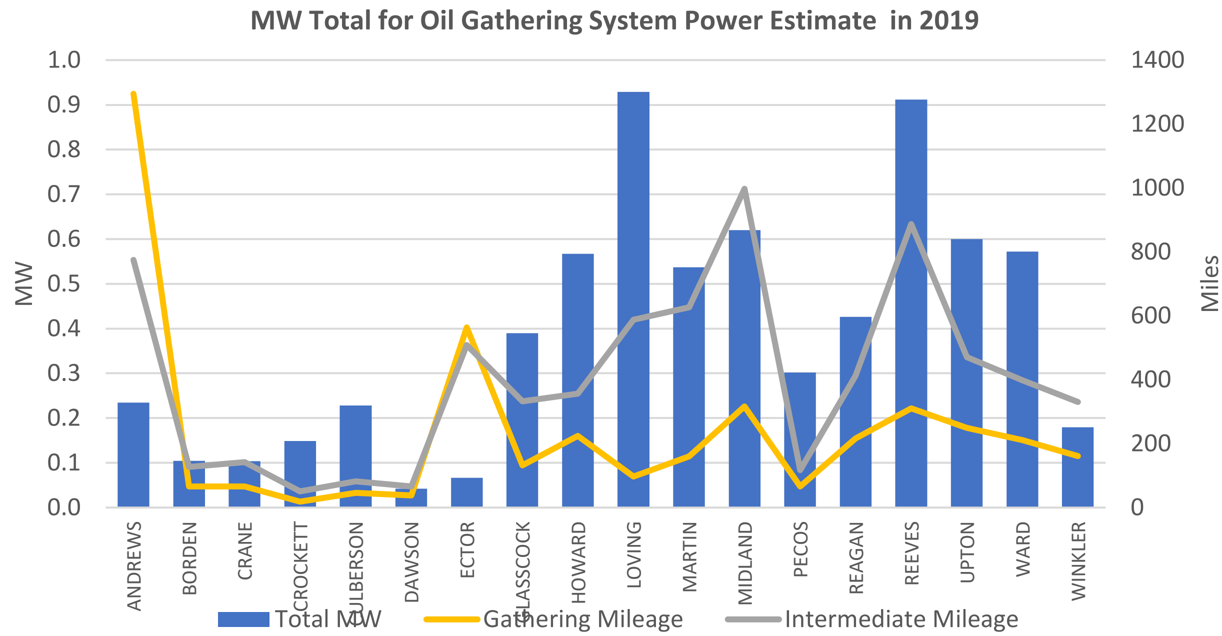

Figure 5-12 Power requirement for oil gathering system and average oil gathering line mileage by county

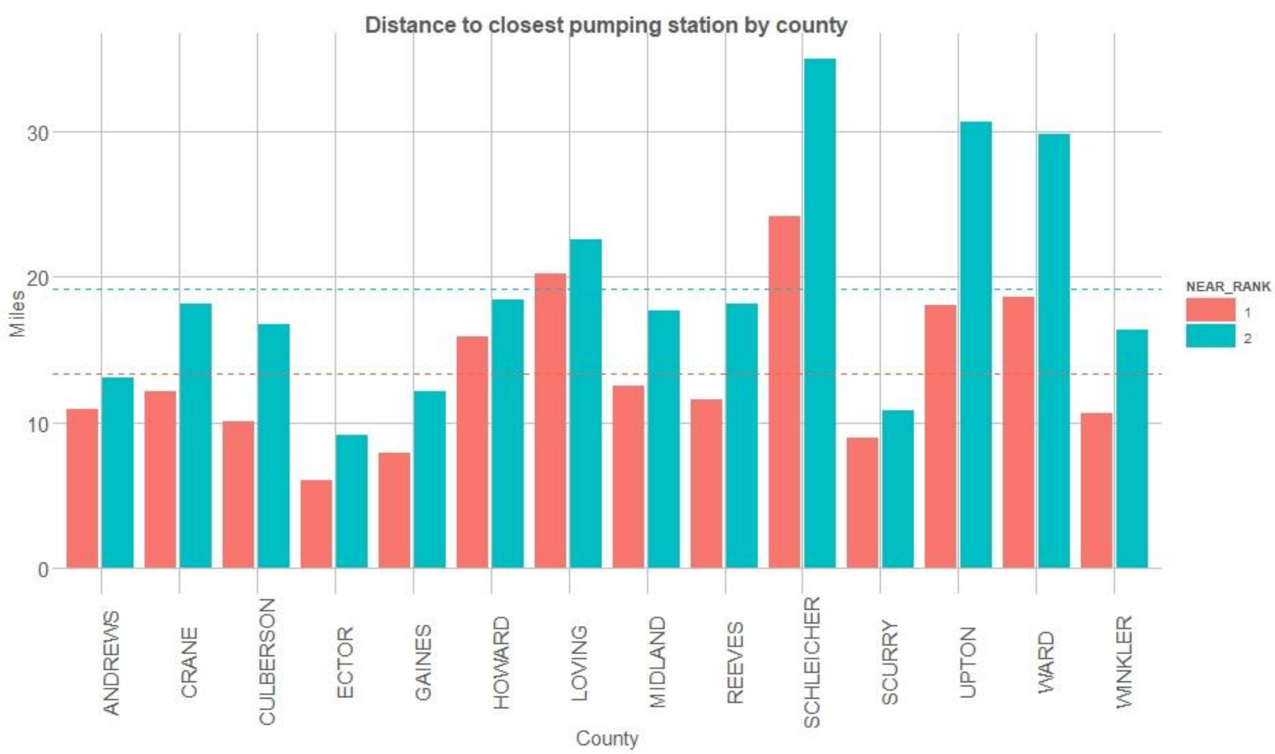

Figure 5-13 Average distance from a producing well to a nearby pumping station[4]

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[4] There are only 14 counties containing data of pumping stations used for the study.

5.4. Gas processing and treatment

The natural gas used by consumers is composed almost entirely of methane. However, although still composed primarily of methane, natural gas found at the wellhead is by no means as pure. Raw natural gas comes from three types of wells: oil, gas, and condensate wells. Natural gas that comes from oil wells is typically termed associated gas, and most of the natural gas from the Permian Basin is associated gas. However, even in wells primarily producing gas, referred to as gas wells, the raw natural gas still contains a semi-liquid hydrocarbon condensate. The light hydrocarbons (besides oil) left in wet gas streams commonly exist in mixtures of principally ethane, propane, butane, and others. In addition, raw natural gas contains water vapor, hydrogen sulfide (H_2S), carbon dioxide, helium, nitrogen, and other compounds.

Major transportation pipelines usually impose restrictions on the makeup of the natural gas allowed into the pipeline. That means that before the natural gas can be transported, it must be purified. The ethane, propane, butane, and pentanes must be removed from natural gas. Natural gas processing consists of separating all of the various hydrocarbons and fluids from pure natural gas to produce what is known as pipeline-quality dry natural gas, and Figure 5-14 demonstrates the schematic of a gas processing plant.

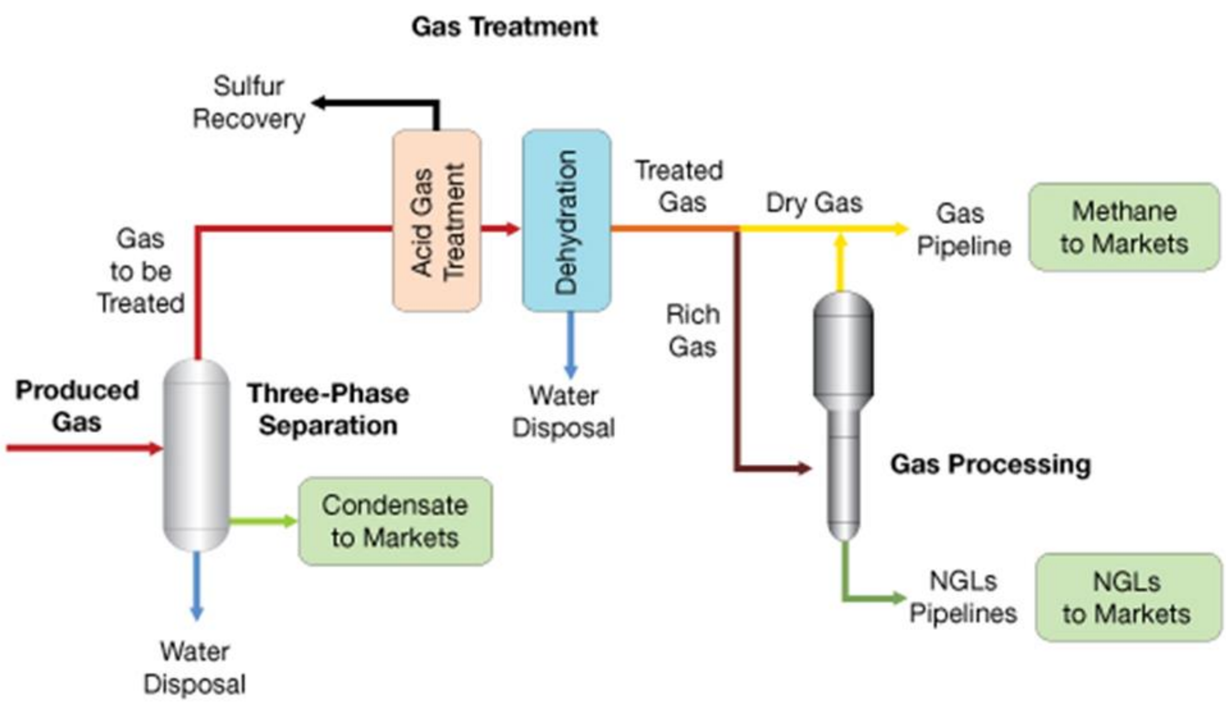


Figure 5-14 Gas treatment plant (Source: Midstream Gas: Gas Processing and NGL Markets. ihrdc.com)

Figure 5-15 shows the processing capacities by county in the study area. Not all counties have processing plants— local gas can be processed in the county if there is an existing processing plant, or it can be transported across the county for processing when there are no or insufficient local processing capacities.

Regarding the power requirements for processing plants, the Williston Basin Study 2012 estimates around 15 MW per 100 mmcfd of raw gas for facilities built between 2015 and 2019. The Oncor IHS Study (2020) uses a matrix to calculate throughput versus the power requirement of gas processing plants. The processes required at a processing plant will differ greatly depending on the quality and mixture of raw natural gas from different basins, and so will its energy and electric load. For two reasons, the current study takes an average load factor of 7.2 MW per 100 mmcfd. First, consider that some of the on-site processes use gas-fired generators. Second, some portion of up to 10% of raw natural gas is lost through the transportation and processing process for fuel use and other losses. Figure 5-16 shows the county level load requirement for processing in 2019.

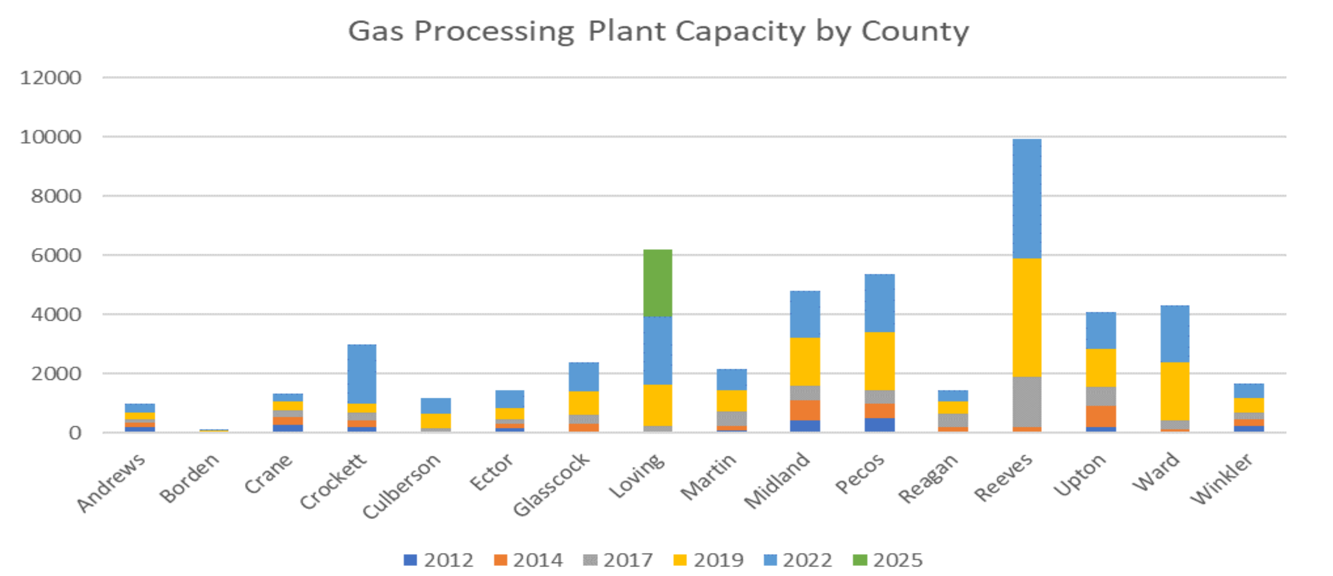


Figure 5-15 Gas processing plant capacity by county

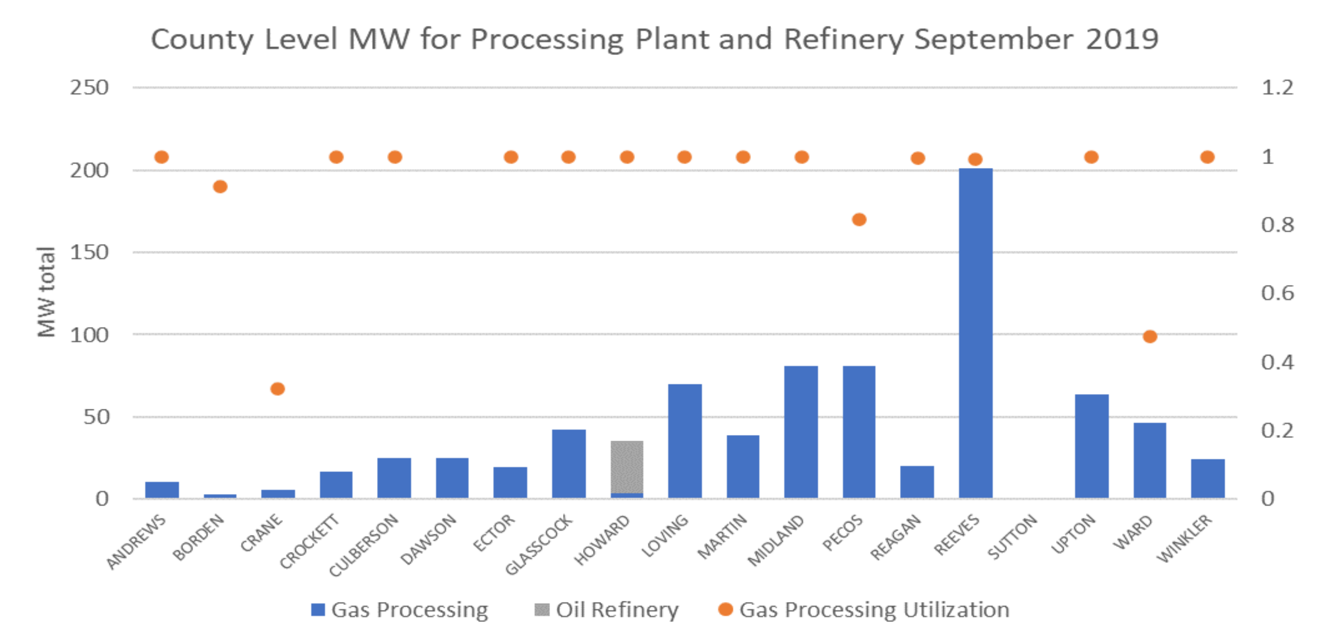


Figure 5-16 County-level load estimate for gas processing and oil refinery

There are about 18.2 bcf per day of processing capacities in the Permian with small amounts of announced capacity expansion. As natural gas production increases in the Permian, NGL production also increases. It is worth noting a trend in oil and gas production in the Permian, which is that the gas has been increasing faster than oil in recent years. The reasons come from two factors: first, there is less flaring. In recent years, the flaring of produced gas had become almost a crisis in the Permian Basin as pipeline backlogs had forced producers to either shut-in wells or flared the produced natural gas. New natural gas pipelines combined with oil well shut-ins alleviated the flaring in 2020, with estimated flaring around 0.15 bcf per day compared to about 0.5 bcf per day in 2019 or earlier. This drop in flaring also means more NGL is extracted out of the gas stream. The second reason is new wells with higher gas-to-oil ratios, including nearly drilled wells and the restarting of previously drilled wells.

All producing wells are mapped to the closest two processing plants in the study area for the historic period. This approximates the distance from a well to its processing plant. The future processing infrastructure follows a similar pattern: processing plants are built to optimize their intake from producing wells. New plants would be added close to the new drilling area. Figure 5-17 shows the average distance from a well to its processing plants, where 1 indicates the closest processing plant, and 2 indicates the second closest processing plant.

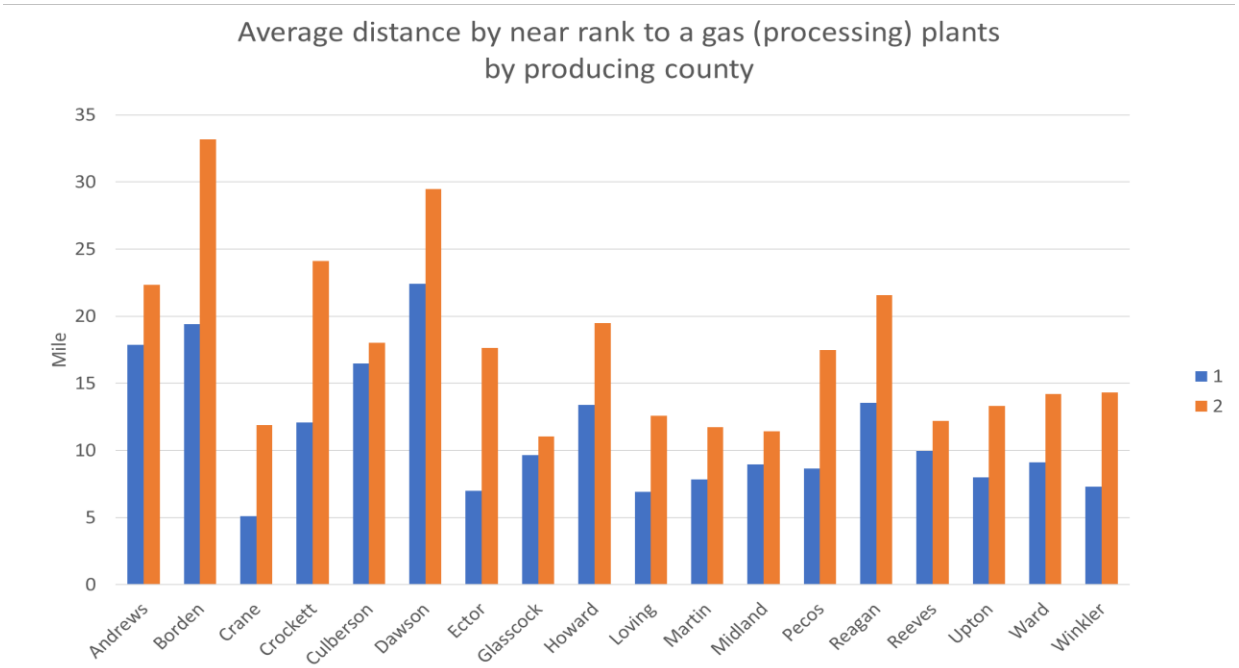


Figure 5-17 Average distance from producing well to a nearby processing plant

5.5. Oil refinery

Oil is transported to a refinery for further processing. Refineries represent about 4% of total energy consumed in the United States and about 15% of all industrial consumption. However, the majority of the oil from the Permian is transferred out of the basin for refining, and there is only one existing refinery in the Texas portion of the Permian Basin: Alon USA Big Spring Refinery in Howard County, located with a 73,000 bbl/D nameplate capacity, est. 30 MW with an average 67,000 barrels per day throughput. Furthermore, it is worth noting that there are two announced new refineries in the study area:

MMEX Resource in Pecos County, with three proposed phases. According to its official project website, phase 1 includes 10,000 barrels per day of a small and modular unit with about 4 MW electricity requirement and 6 MW for CO_2 capture. The second phase includes blue H_2 60 ton/d via steam methane reformation (21,600 tons per annum) with 13,000 mcf/d dry natural gas with an expected 25.5 MW power requirement It also will have integrated solar power on-site for up to 10 MW. Phase 3 includes green H_2 (not related to oil and gas) and will have 188 MW of power required for electrolysis up to 50 tons per day. It is unclear if additional renewable capacity is on-site for the last phase. Assuming the project includes its on-site renewable capacity for phase three and part of phase two, there will be a 25.5 MW power requirement from the grid from phases 1 and 2.

Meridian Energy 60,000 barrels per day in Winkler County with an estimated 30 MW power requirement. There is no specific announcement of on-site power capacity.

5.6. Major transmission pipeline

The products (oil, gas, and NGL) often need to travel a great distance to their point of use or the next stage of the value chain.

Natural gas transmission pipelines here focus on transmission lines carrying processed natural gas from the producing area, often at the tail end of a processing plant, transporting gas long distances at high pressures (often 200-1500 psi) to the downstream market. Interstate pipelines that cross the state border are regulated by the Federal Energy Regulatory Commission, and intrastate pipelines are regulated by the state. There are 17 major transmission pipelines out of the Permian Basin, and Figure 5-18 shows the historical pipeline receipts of these pipelines through the year 2020 in the unit of mmcfd. There are almost 12 billion cubic feet per day of processed natural gas moved out of the Permian Basin in 2020. The current study would only focus on the electric load that would be occurred for transporting natural gas out of the basin via these transmission lines. In other words, those are the volumes that flow across the basin via these transmission lines.

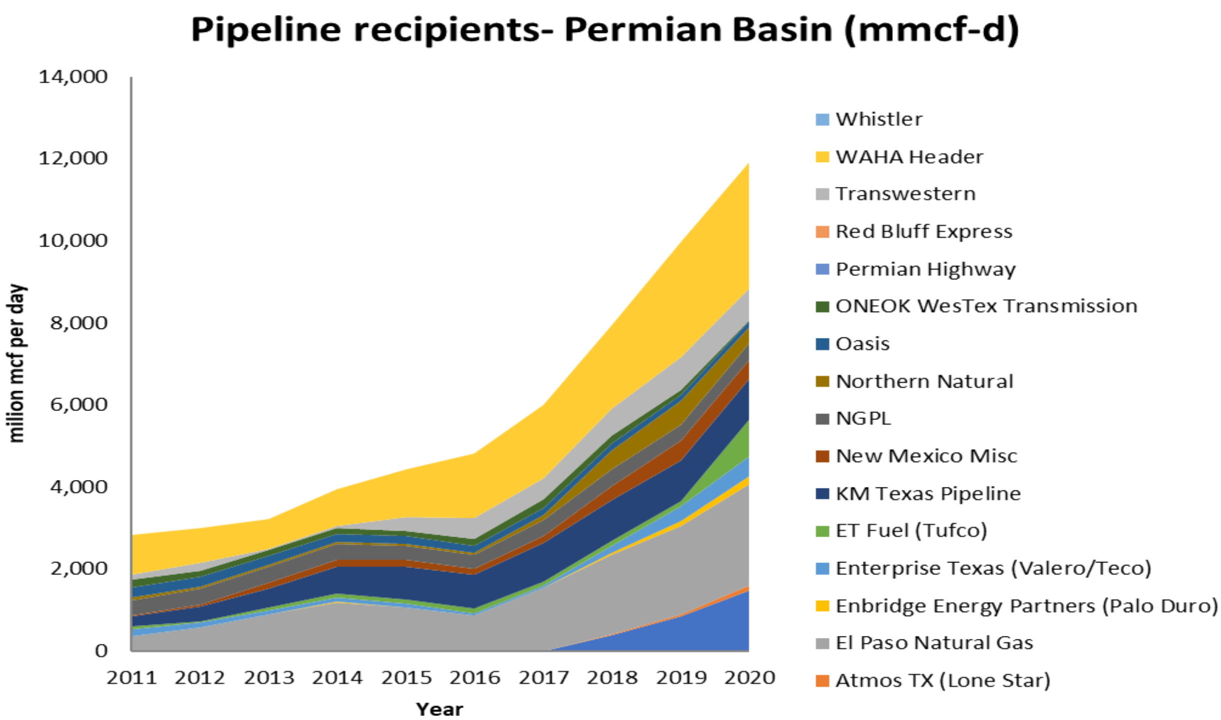


Figure 5-18 Gas pipeline receipts in the Permian Basin

For a simple estimate of the load requirement from transmission lines, there are two assumptions: routes of the transmission pipelines would not change materially from the current, while expansions and additions in similar routes of way are likely to change as the production grows. Second, based on the GPCM® North America gas pipeline competition model, which provides the producing region pipeline flow forecasts, Figure 5-19 shows that the forecasted outflow of the Permian Basin sliced by its destination markets remains steady from the year 2020 through 2035. In other words, the cross-county flow remains proportionally stable as the production grows.

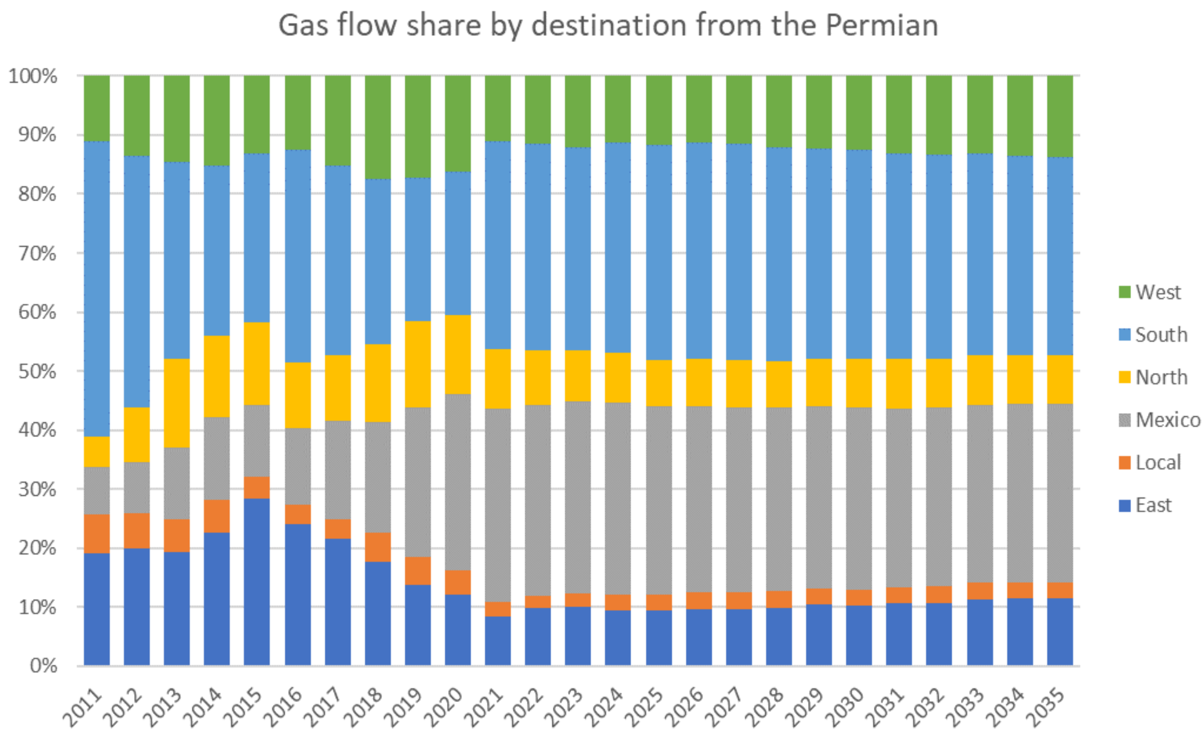


Figure 5-19 Gas flow share by destination from the Permian

Similar to the load for the natural gas gathering system, it is important to realize that the load requirement for these major transmission lines could be significant. Still, the actual load connected to the grid is relatively small. The percentage of electrification of compressors impacts this part of the load requirement on the grid.

The raw gas is made of natural gas (methane) and condensate. NGLs come from oil (associated) and gas (nonassociated), and NGL numbers are related. NGL's power requirement for pipeline transportation is around 50% of oil transportation due to its lighter density (Higher API). NGL mileage is around 60% of the oil pipeline in this study. The major pipeline load-requirement oil and NGL pipelines are calculated as 50% of their load requirement of local gathering load based on two simple assumptions. First, a larger pipeline is more efficient in transporting than smaller pipelines for the same volume; second, the mileage of a larger pipeline is less than 50% of the local gathering line for oil and NGL.

Chapter 6. Permian oil and gas production outlook

This section includes the basic methodology and structure of the TORA consortium at the Bureau, providing the foundation for oil and gas activities forecasts.

6.1. Outlook analysis overview

TORA's integrated tight oil and gas play analysis and assessment workflow (Figure 6-1) rests on the foundation of a robust subsurface framework which includes stratigraphic analysis, petrophysical interpretations, facies descriptions, pore pressure analysis, and fluid properties estimates, integrated into a basin-scale geologic model. It includes well-level decline curve analysis to estimate the production potential of existing wells and to inform the likely productivity and production history of future wells. With completion and production data from existing wells and geologic assessment from the TORA geologic model, the productivity of existing wells is modeled, and fundamental controls on productivity are revealed using advanced data analytical approaches. The geological-based productivity model and the revealed controls are necessary to predict the production of future wells for all undrilled regions at the basin scale. With expected drilling and completion practices, and geologic attributes derived from the geologic model as input data, we then use the productivity model to predict the annual production profile, hence EUR (estimated ultimate recovery), of a representative future well in each square mile block of the basin per formation. We then conduct well spacing analysis and estimate the remaining well inventory per block, per formation. Assuming drilling and completion practices remain the same as the most recent three years, we assess Technically Recoverable oil and gas per block per formation. Our granular technical recovery resource (TRR) assessments are strongly linked to geology and reservoir data and reflect the current drilling and completion practices. TRR is based on a large inventory of wells, some of which may never be drilled due to lower-tier in-place volumes and reservoir porosity and a gas-oil ratio (GOR) that is too high. The latter is more of an issue in the western Delaware Basin than in the Midland Basin. TORA's expected drilling analysis and production outlook workflow considers economic / investment constraints and profitability and connects with subsurface models, reservoir engineering, and the TRR assessment, allowing us to assess the impacts of various energy prices on annual oil and gas production for each formation in any tight oil and gas basin. While the upper right portion of the workflow is the focus of this chapter, the results are directly tied to the work done in the upper left and bottom portions of the workflow diagram.

Figure 6-2 shows the TORA-focused area. TORA focuses on the formations and intervals that account for the majority of unconventional production (horizontal wells and fracking). Looking at the current top landing zones by 12-month cumulative oil, for the Delaware Basin, TORA production outlooks and forecasts will cover almost 70% of those volumes, and for Midland, TORA can account for well over 80% of first-year production.

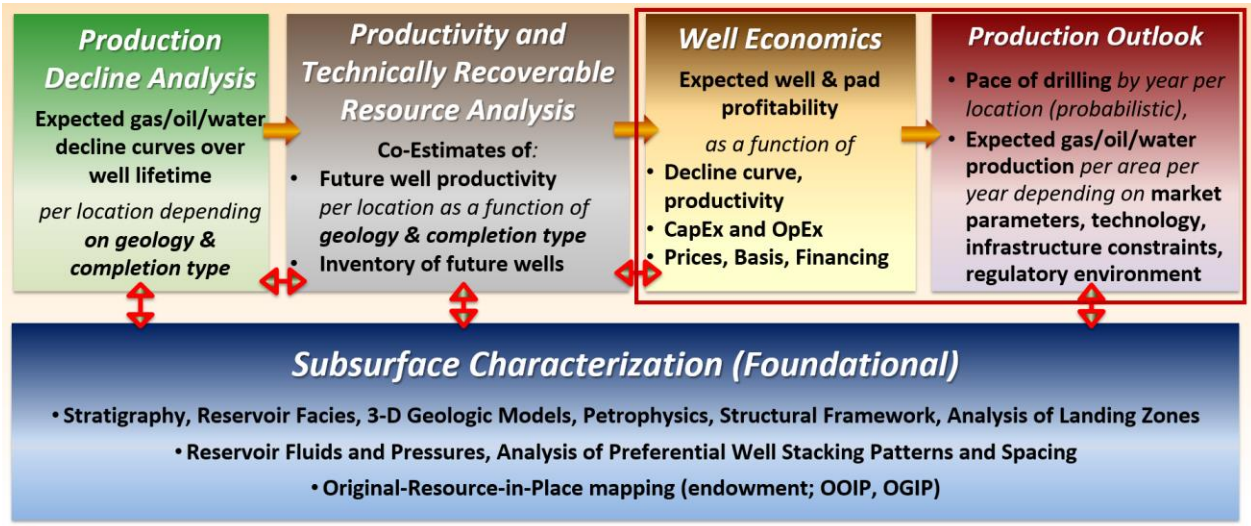
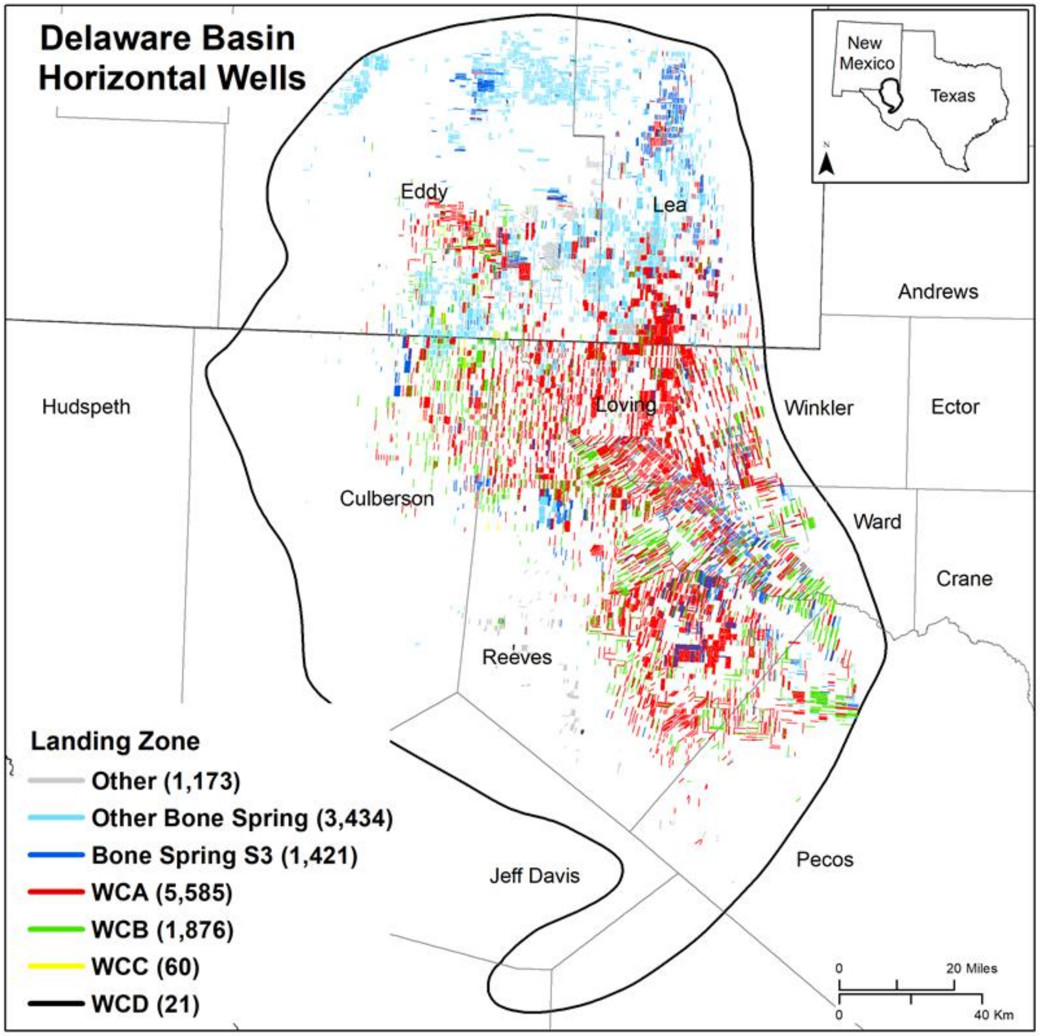


Figure 6-1 TORA's integrated workflow. The red rectangle highlights the production outlook workflow.



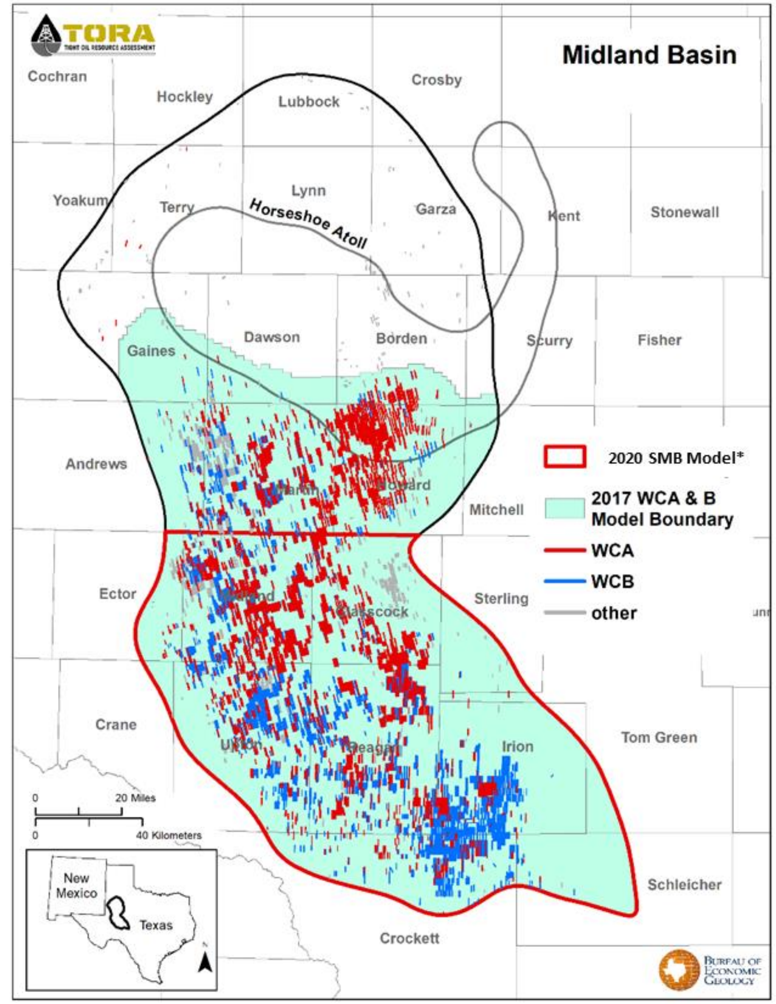
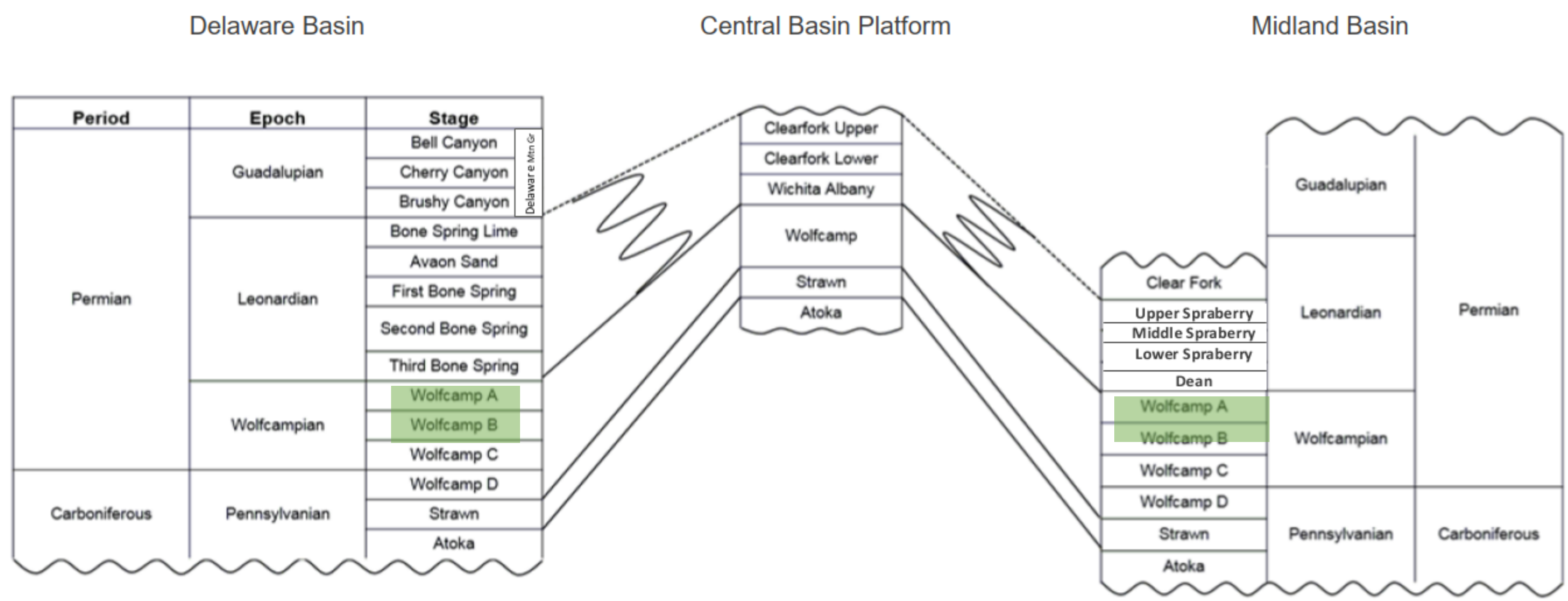


Figure 6-2 TORA focus areas



Source: U.S. Energy Information Administration based on Enverus DrillingInfo Inc., U.S. Geological Survey.

Figure 6-3 Stratigraphic schema from the Permian Basin.

The Permian Basin presents a particular challenge in that there are so many formations to evaluate and for horizontal drilling, two major subbasins across Texas and New Mexico. Another complication is that associated gas is produced from most of the horizontal wells targeting tight, low-permeability reservoirs, with GOR highly variable for wells located in different parts of these vast subbasins. With over 30,000 wells now drilled in the Delaware subbasin (DB) and Midland subbasin (MB), there is an enormous amount of data to consider each time one of these outlooks is constructed, given that we must keep track of each producing well and its attendant decline each year is on production. On average, the first-year oil production accounts for some 30 percent of the ultimate EUR per well. Without new drilling, total production would rapidly decline. There is also the complication of "DUCs," wells that have been drilled but not yet completed. Wells may be drilled in year 'x' but not completed until several years later when more cash is available to the producer and/or prices are higher. In this case, production may be added in year 'y,' which is tied to a well drilled several years earlier. This is exactly what we see today in the Permian Basin, with oil prices over $90/bbl.

The study described herein focuses on the Third Bone Spring Sand, Wolfcamp A and B formations of the DB, and the Wolfcamp A and B formations of the MB, shown in Figure 6-2. Figure 6-3 shows the stratigraphic schema for the Permian Basin with highlighted formations.

The goal of TORA's outlook model is to project how many wells will be drilled and where they will be drilled in the future, depending on commodity prices, costs, and technology assumptions. Knowing the number and locations of future wells, one can calculate the total annual incremental production. Figure 6-4 shows the historical annual production increments, with different colors marking production from wells drilled in different years.

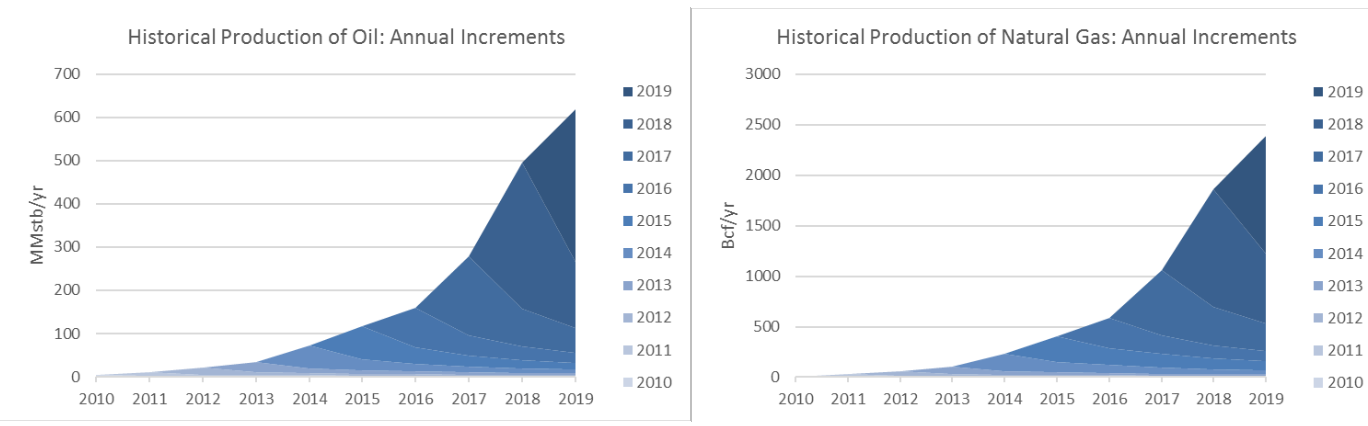


Figure 6-4 Oil and natural gas production history from selected formations of the Permian Delaware Basin (BSS3, WCA, WCB1&2) with marked incremental annual production additions. BSS3: the Third Bone Spring Sand. WCA: Wolfcamp A. WCB1&2: Wolfcamp B1 and B2.

Each year's production is equal to the sum of the legacy production, or the (declining) production from the wells drilled in the past, plus production from the new wells. Formally, the entire play production Q_T in a given year T is the sum of annual increments over $t = \{t_s, .., T\}$:

$$Q_T = \sum_{t=t_s}^{T} Q_t^T$$

Where Q_t^T represents the sum of production in year T from wells drilled in year t, representing the thickness of a production band in year T from wells drilled in year t (Fig. 2). In the following sections, we formulate an analytical approach to project play production profiles (annual production time series), $\boldsymbol{Q}_t$, from wells expected to be drilled per future year. Combining these values with the expected production of existing wells (t<=2019) provided by TORA's decline curve analysis, we are able to generate a production outlook at the play scale from both existing and future wells. To be specific, we provide the methodology for: 1) how to estimate the number of newly-drilled wells in a given future year (n_t), also referred to as "development pace" or "drilling pace," and 2) how to estimate the distribution of expected drilling across geographical locations and translate the expected drilling into expected production profiles.

6.2. Drilling pace

We build a cash flow model to relate total capital spending on new wells in year t, K_t, to the netplay cash flow at the end of the previous year t-1. We assume that producers are disciplined and only rely on the play's reinvestment of their own capital. For historical wells without capital spending data, we used the average costs and completion attributes (true vertical depth [TVD], lateral length drilled in feet [LL], hydraulic fluid used in gallon per foot drilled [HF], proppant used in gallon per foot drilled [Prop]) to estimate the capital cost of an individual well. For undrilled future wells, we used the average costs of wells drilled in 2019 and expected completion attributes to estimate capital cost.

6.3. Drilling locations

We then build an 'expected drilling decision model' to distribute n_t across the play based on the analysis of where historical wells have been drilled in terms of their first five-year productivity history (defined as the cumulative first five years' produced oil per 1000 ft lateral length) and how the number of wells drilled and their locations within the play change with energy price. This model attempts to capture the very complex drilling dynamics when producers decrease their drilling investments and move to locations with higher productivity if the prices drop, and increase their drilling and completions investment and expand their drilling and completions if prices increase. The model allows us to project the drilled locations and to model / estimate how quickly these locations will be developed (e.g., drilled and completed), given different energy price scenarios.

6.4. TORA data output

This section lists and describes the TORA data output used for electrical load analysis. Notice that this outlook analysis is based on a TRR assessment study conducted in 2020, when 2020 production data itself was largely unavailable. Therefore, the production outlook is projected starting in the year 2020.

a. Water-to-oil ratio, TVD, API gravity, and gas-to-oil ratio per one square mile block per selected reservoir/formation.
b. Estimated annual production (gas, oil and water) volumes from existing wells that landed in the defined reservoir/formations.
c. Estimated annual production (gas, oil and water) volume of the representative future well in each one square mile block of the selected reservoir / formations.
d. Expected drilling and remaining well inventory per one square mile block per future year (2020-2035) under three price scenarios.
e. Production (oil, gas and water) outlook from future wells per one square mile block under the three price scenarios.

Chapter 7. Develop electric outlook of West Texas

This section aggregates all the historical load from 2012 through 2020, based on the estimation method from Chapters 3 and 4, and develops forecasted load estimates from 2021 through 2035 based on the expected drilling and production outlooks from TORA. As discussed in Chapter 2, the number of wells and production level are two different indications and measures of activities in the Permian Basin. This chapter will also discuss the assumptions and rationale of constructing future scenarios based on the two aspects of activities.

The organization of the chapter goes through the three major components of consideration in developing a forecasted load assessment, which are demonstrated in Figure 7-1.

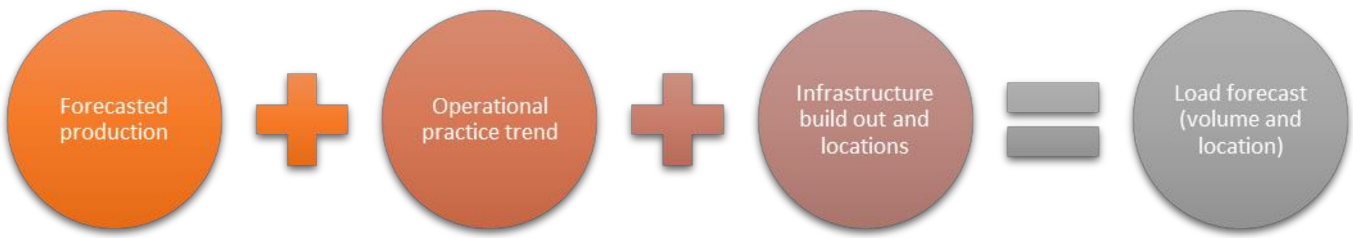


Figure 7-1 Components of load outlook

The first and foremost component is forecasted production and activities in oil and gas fields in Permian. There are two main points to address here: the first is to establish the historical production and its relation to load, and the second is to have future oil and gas production as the foundation of future load forecast.

The second component is operational and practice trends, which would impact the load requirement in the basin. This study focuses on the electrification level for the midstream sector in the basin. This sector presents a great potential for load requirements on the grid.

The last component addresses the location of future load, and it is not a trivial question here. For historical load estimate, it is relatively straightforward to identify the location of the load, for most of the activities, like the upstream site, saltwater disposal sites, or locations of processing plants and refineries. For midstream activities, it is less obvious where exactly the load is occurring along with the pipeline network. The same challenges remain with additional uncertainties for future activities and load requirements since much of the infrastructure is not yet built to support incremental production and flow. Therefore, a general methodology to locate the future load is addressed here.

7.1. Historical aggregated electric load from oil and gas activities

This section discusses the historical aggregated oil and gas activities and compares them with the estimated historical total load from these activities. This helps to lay the foundation for the relationship between activities and load.

Figure 7-2 shows the number of wells by type in each county from 2012 through 2021, showing the different levels of activities across counties. There are fast-growing horizontal wells compared to vertical wells for those located in the heart of the Delaware Basin or Midland Basin. More vertical wells are drilled in the Central Basin Platform and other areas, like Andrews county.

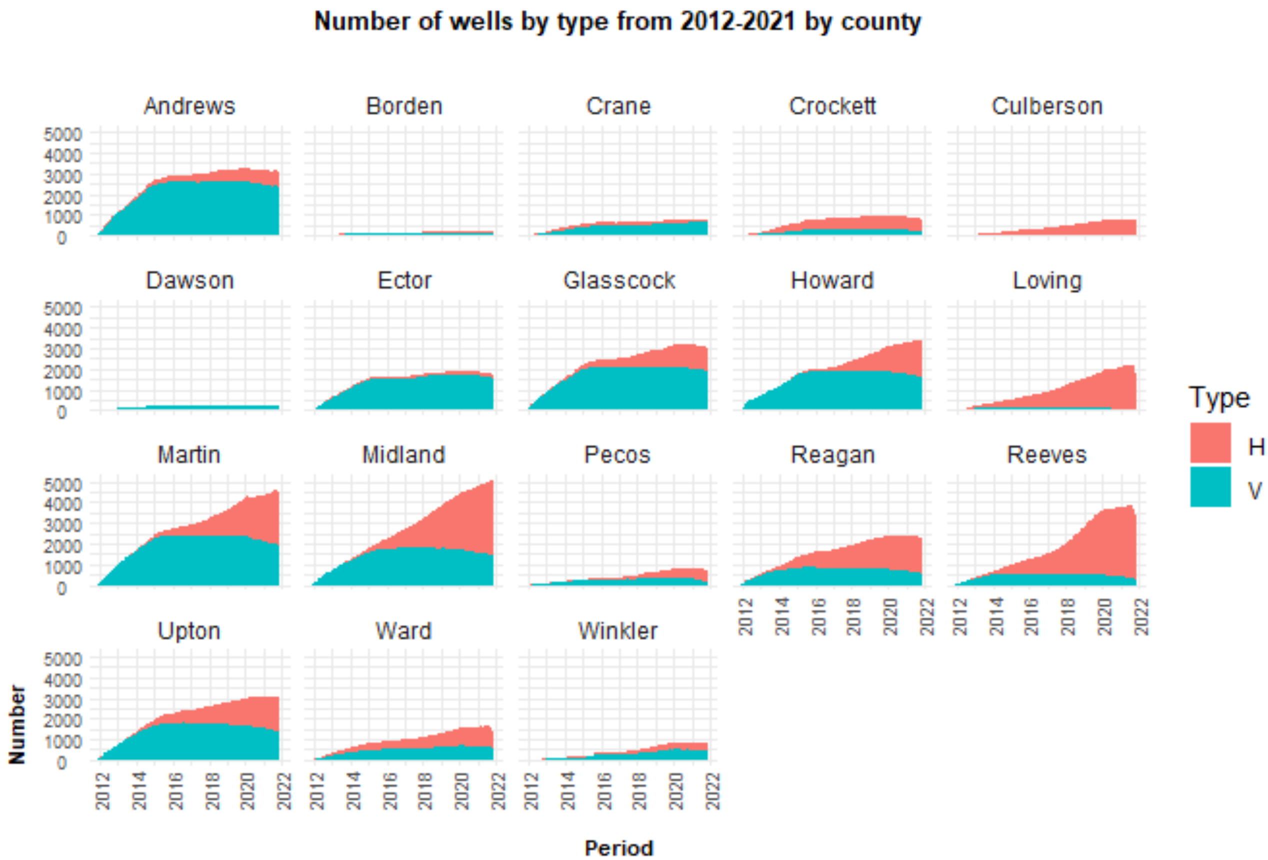


Figure 7-2 Number of wells by type from 2012-2021

Since the assumptions of the load are mainly tied to the throughput volume of oil, gas, or produced water, the production volume is more important and indicative of the load. There is a reason for the sharp increase in horizontal wells. Figure 7-3 shows that horizontal wells produced about 3-5 times higher productivity by comparing total crude production (million bbl per day) for vertical and horizontal wells in the study area. Hence, horizontal wells' activity and production drive the production of Permian going forward.

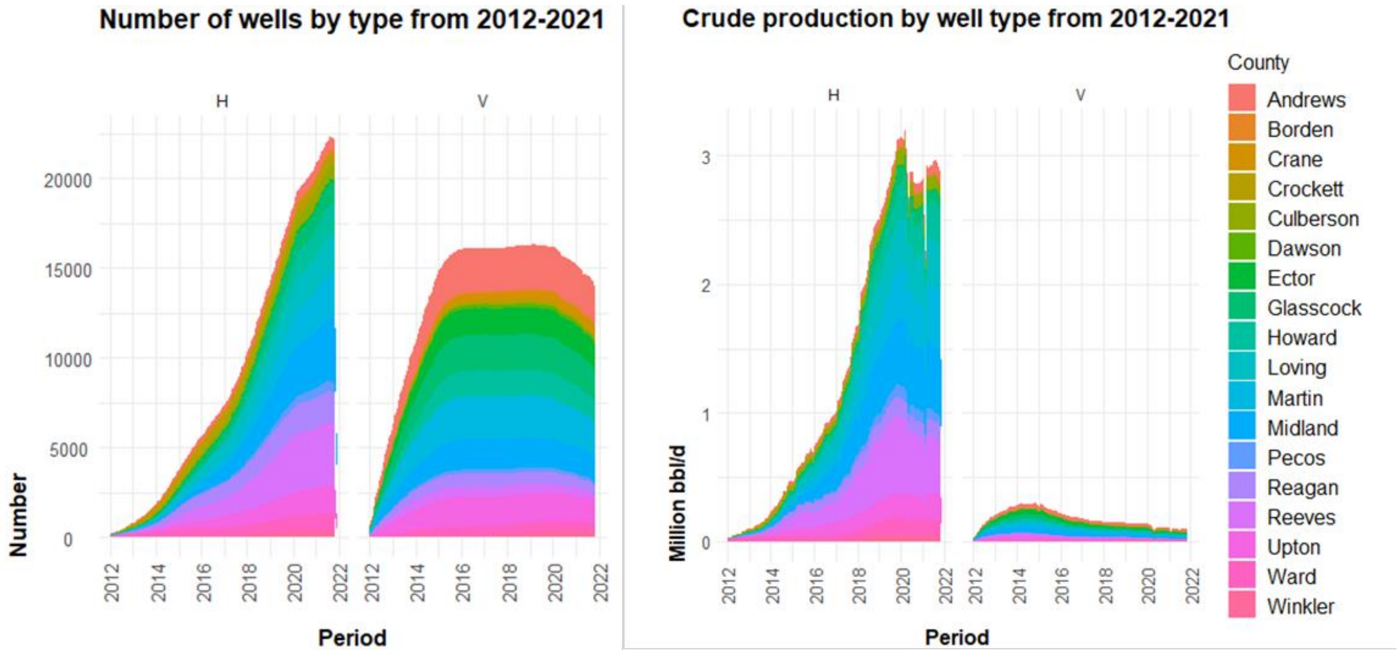


Figure 7-3 Comparison of number of wells and production by well type 2012-2020

Figure 7-4 aggregates all products at the county level together in one chart, with gas converted into barrel equivalence unit to show the relative magnitude of the production volume out of Permian as a whole. Note that produced water is a significant part, especially in Reeves county, implying a higher load requirement for produced water facilities nearby.

As discussed in Chapters 4 and 5, it is important to recognize that the load is not necessarily fulfilled via the electricity grid depending on the specific activities.

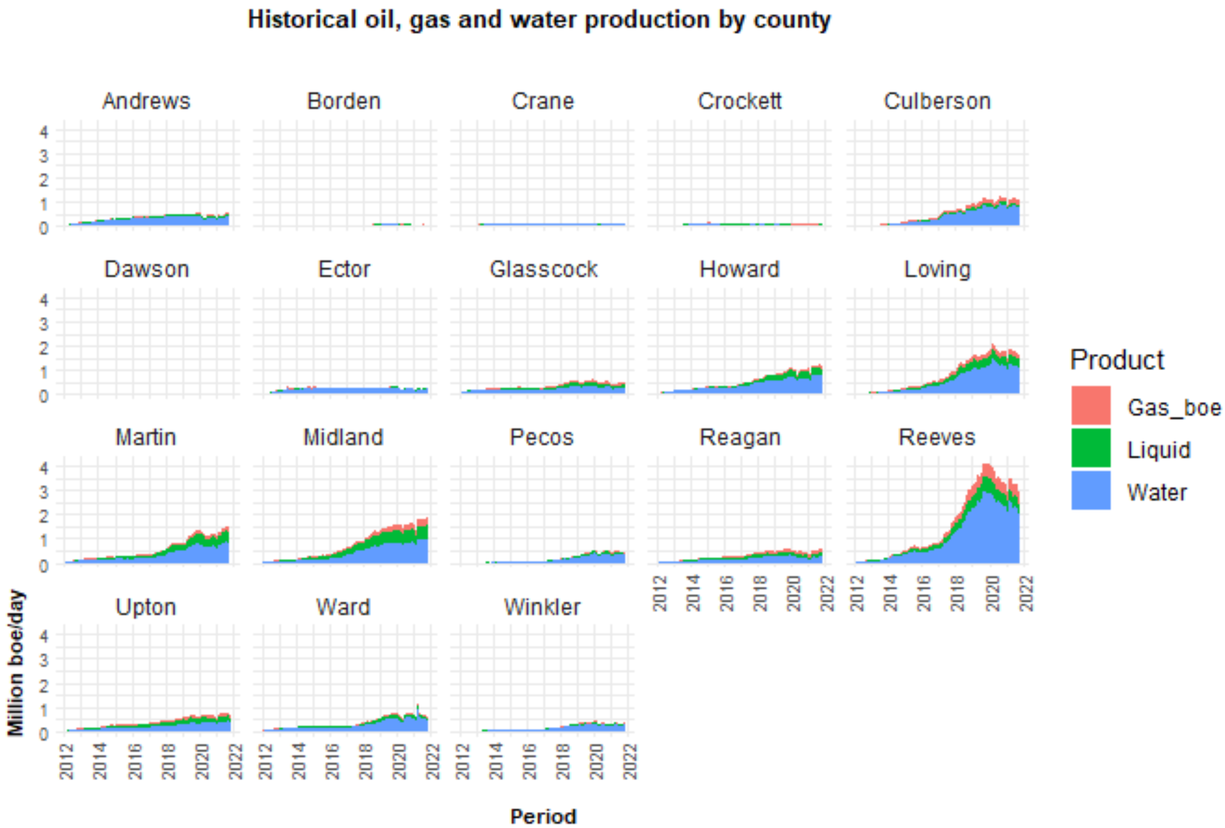


Figure 7-4 Historical productions of oil, gas, and water 2012-2021 by county

For example, the use of ESP upstream mainly relies on grid power whenever and wherever possible. Hence, it is reasonable to assume that almost 100 percent of the ESP power requirement is reflected in the historical data report load. On the other hand, most compressor stations still use gas-fired turbines without a direct grid connection. Therefore, only 10 percent of the energy requirement for transporting natural gas through the gathering system is assumed to be connected to the grid. Here are the assumptions used, based on the analysis from previous chapters, and Figure 7-5 shows the total electric load estimates in the historical period:

- Natural gas midstream, including gathering and major pipeline-10 percent
- Oil midstream, including gathering and major pipeline-100 percent
- NGL midstream including gathering and major pipeline-100 percent
- Artificial lift: ESP and rod pump–100 percent; and gas lift 0 percent
- Saltwater disposal wells (SWD)–100 percent
- Processing–powered by the grid, but some processes use gas-fired turbines, like compressors, and uses 7.2 MW per 100 mmcfd of **raw natural gas for processing**
- Refining is powered mainly by grid power, but a small amount for the study area.

The load is plotted based on the type of contributing activity, and it is clear that the upstream load is mainly driven by artificial lift and SWD, while the midstream load is driven by load from the natural gas system, in terms of its midstream transportation and processing activities.

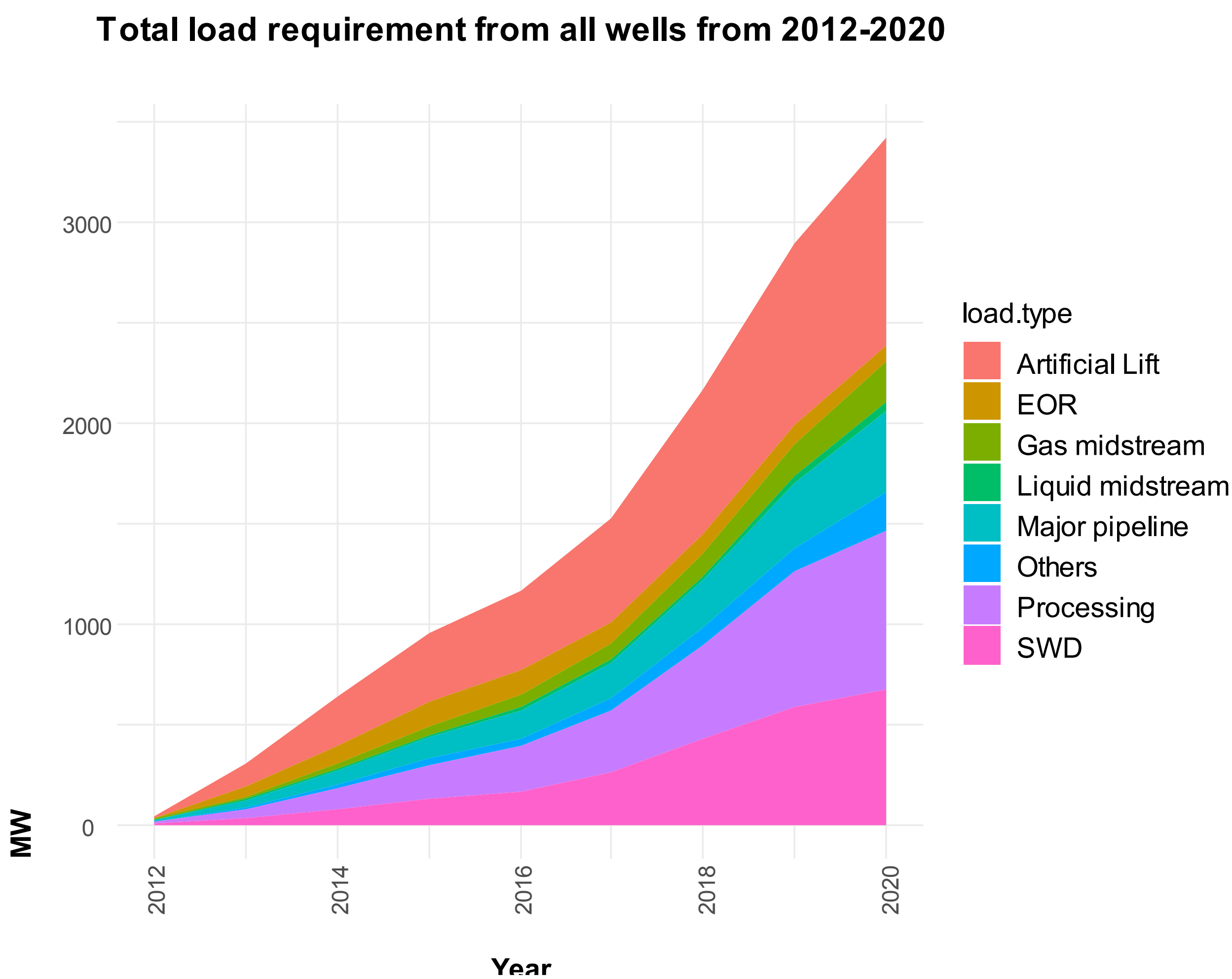


Figure 7-5 Total load requirement from all wells 2012-2020

7.2. Scenarios definition

The historical estimated load from oil and gas has provided a basis for developing forecasted load requirements for similar activities in the future. We use the production outlook at the well level for oil, gas, and water from the TORA research consortium group at the Bureau, discussed in Chapter 6. The point of interest here is to identify the range of uncertainties of incremental load in the future by oil and gas activities in the Texas portion of the Permian. Therefore, it is important to identify the factors directly impacting the outcome. Here are two sets of direct factors to be considered:

In this project, the production outlook considers WTI oil prices of $35 (low), $70 (base), and $90 (high) per barrel based on historical data (Figure 7-6). Note that basis differential adjustments for the Permian region were applied when developing the production outlooks using these price scenarios. The projected long-term oil ranges from $35 to $90 per barrel of oil, covering the historical oil prices from 2011 to 2020, indicated in the gray line of Figure 7-6. For all three selected price scenarios, the NGL price is assumed to be fixed at $25/bbl in the long term. For the base and high oil price scenarios, the gas price is projected to be fixed at $2.5/MMbtu in the long term. For the low oil price scenario, the gas price is projected to be fixed at $3.0/MMbtu, considering that associated gas decreases when oil production decreases and decreased gas supply will potentially increase the gas price.

Figure 7-6 Definition of price scenarios - This study considers three energy price scenarios. At the time of this writing (Feb 2022), WTI oil price has risen to over $90/bbl., historically at the high end of oil prices.

Besides prices, there are other factors that impact the load requirements of oil and gas activities, like the Permian regulation on greenhouse gas emissions. With more stringent regulation on GHG emissions, there could be multitudes of impact on the electric load generated in the production field.

Electrification of operation: currently, many upstream and midstream activities utilize gas-fired generators for power instead of grid connection. Producers or midstream operators may consider switching from gas-fired generators to grid connections to lower the emission rating. There are a couple of areas of potential impact based on the current study:

Midstream natural gas gathering and transportation currently use over 90 percent of gas-fired generators, with about 1000 MW estimated for the entire study area of potential load. Based on inputs from technical interviews, there is an emerging trend of conversion to grid connections for many larger operators and midstream companies in the Permian. However, further research on conversion economics and ongoing market surveying is necessary for future considerations. Therefore, in this study, the scenario definition focuses on the level of electrification operation (mainly for midstream operations of gas) in Permian, among other operation factors. The possible range for scenarios is defined based on the progress of the electrification trend, shown in Figure 7-7.

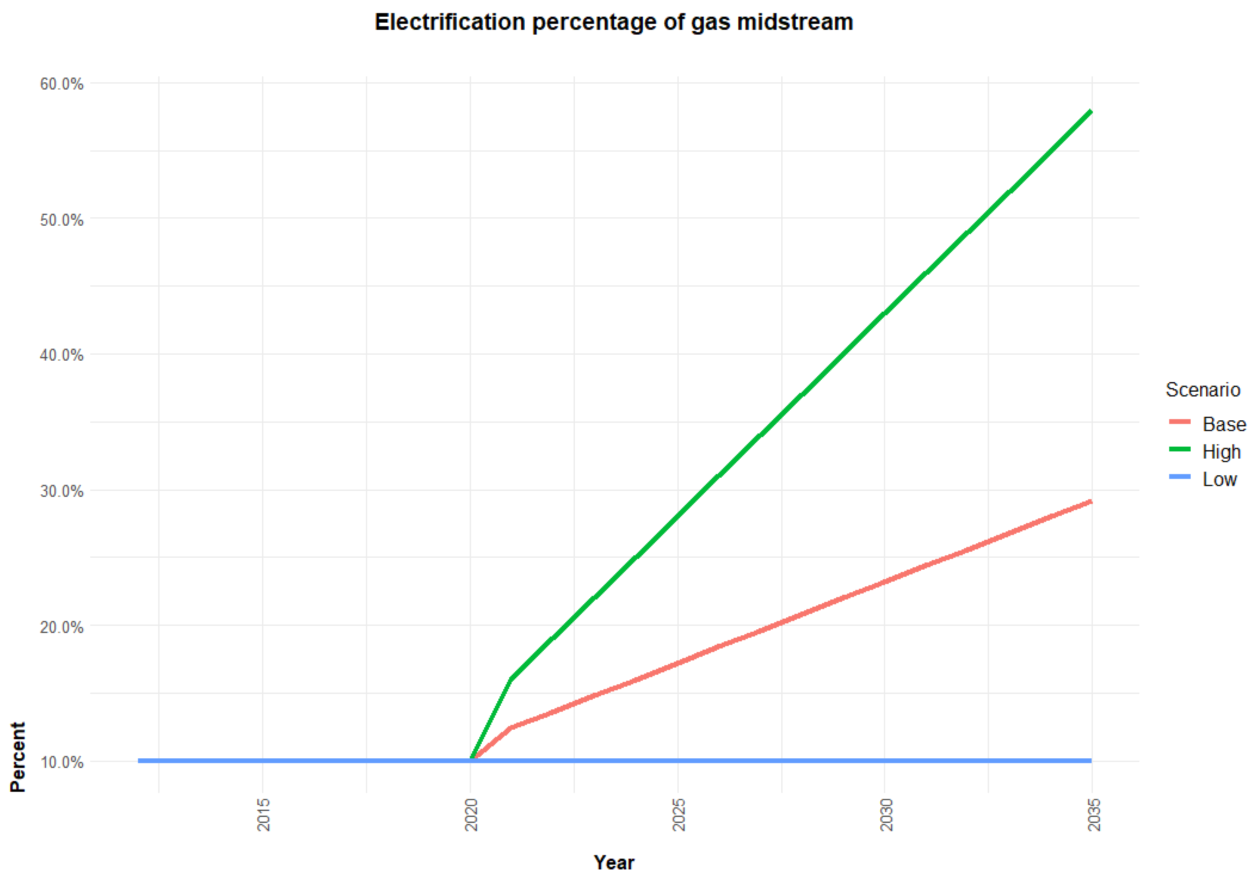


Figure 7-7 Definition of electrification level by scenario

Based on the discussion above, here are three suggested scenarios for the ERCOT load project for this current study:

- Base Scenario: this is the reference case scenario with the most likely current oil price projection ($70/bbl) and gas ($2.5/MMBtu). There is business as usual regulation on GHG emissions with slow progress. The conversion of gas compressors will reach about one-third of the load requirement at the end of the forecasted period.
- High Scenario: oil price remains relatively high at $90/bbl, and gas price stabilizes at $2.5/MMBtu in the long-term. The regulation of GHG emissions accelerates electrification in oil and gas operations. About 58% of the load for the gas gathering will be switched to a grid connection by the end of the forecasted period.
- Low Scenario: oil price remains low at $35/bbl, and gas price increases to $3.0/MMBtu in the long-term. The regulation of GHG emissions on oil and gas activities is slow with more focus on switching from fossil fuels to renewables (remaining 90 percent on the gas-fired compressor).

7.3. Load forecast

This section discusses the methodology and structure that assembles the forecasted production from the year 2021 to the year 2035. In past historical data, each type of activity is summed up based on the number of assets. For forecasted periods, the production outlook can be further divided into two categories of well activities: production from existing wells that have already started production and production from future wells.

First, it is important to understand the drilling activity level in the Permian, which would tie into the number of existing wells that have been drilled and some references of the forecasted drilling activities. Figure 7-8 shows the number of existing wells categorized by the first year of production. Therefore, the total existing well is presented by the accumulated numbers of all past years until 2020 for drilled wells. Existing wells reported production in the historical database and have already started producing. For these wells, the load requirement is based on extending their production outlook of oil, water, and gas from currently observed levels into the future with assumptions of the number of years of operation. Figure 7-9 shows the total expected production by county and by well type for these wells in 2035.

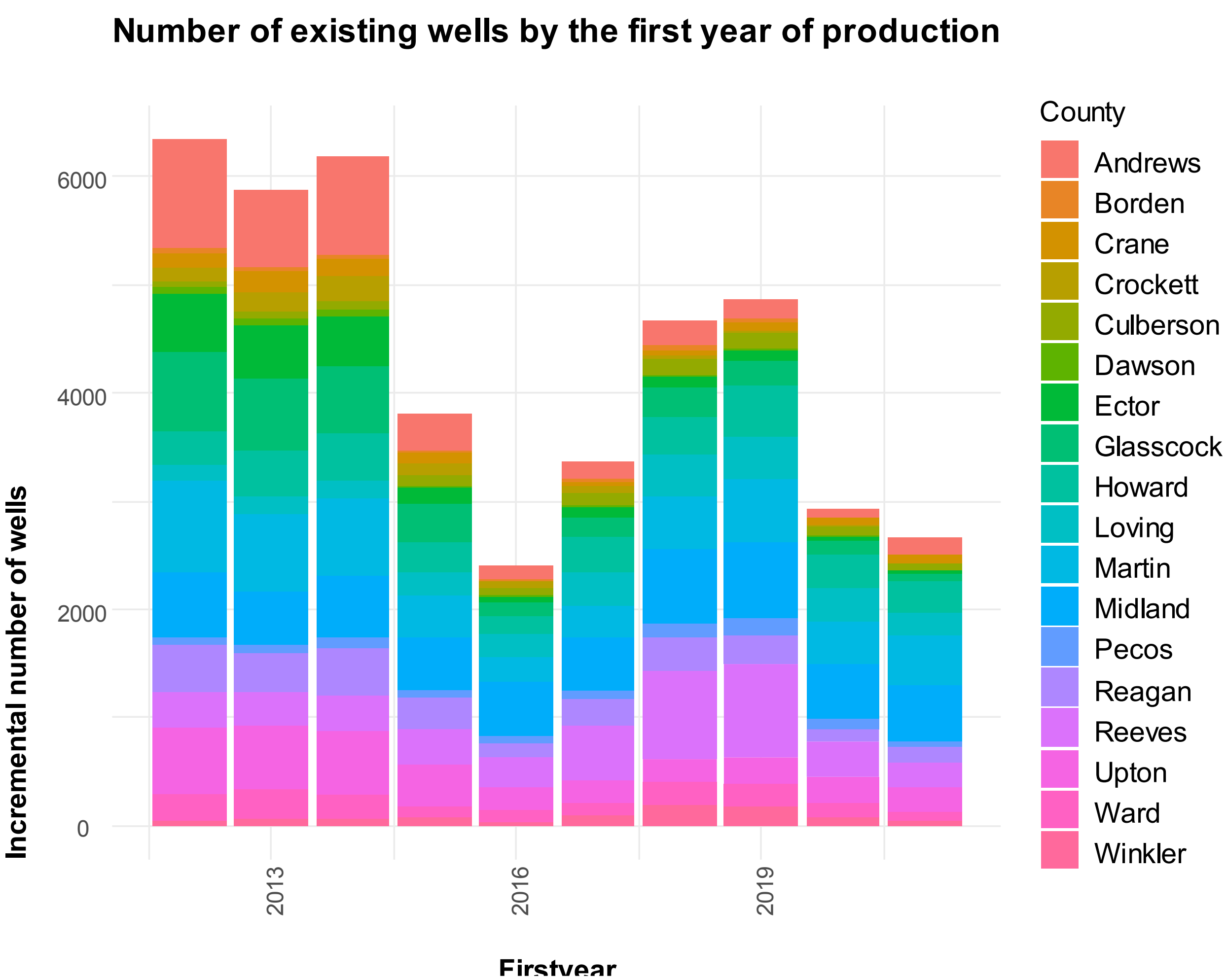


Figure 7-8 Number of existing wells by the first year of production

Figure 7-9 Number of existing wells by the first-year of production by county

Figure 7-10 shows the production profile, also known as the type curve, for existing horizontal wells in the Delaware and Midland Basins, from TORA under Wolfcamp A and Wolfcamp B sections. The existing wells' inventories would go through their typical life cycle with a decline in production volume over time. That is why there is a long decline, representing the declining well-level production on existing wells (starting from different years). If taking a well that was drilled in the year 2020 and the year 2021 is its second year of production, it would appear in the category of the year 2020 in the following plot. Furthermore, each well continues to produce until it is no longer economical to continue. The methodology of estimating existing wells' decline curve (or type curve) is similar to future wells, except the drilling decision was already made. The speed of decline and ratio of oil, gas, and produced water of a producing well is determined based on its subsurface geological formation, operation technology, and cumulative producing intensity.

Besides the horizontal wells in the most prolific areas, there are also existing horizontal and vertical wells that would continue their production in other areas in the Permian, shown in Figure 7-11. The methodology for the non-TORA area is similar to the productivity of an existing well also follows a typical type curve with a year-on-year decline in oil, gas, and produced water production. Those profiles are applied based on the observed current output and the number of years of production of all existing vertical wells.

Figure 7-12 shows the total electric load for these existing wells by scenario. Note that the existing wells are not affected by the price scenario. Therefore, the difference between the scenarios is solely from the electrification assumptions of operation. It is clear to observe the difference in the portion of the midstream sector from each scenario in the chart.

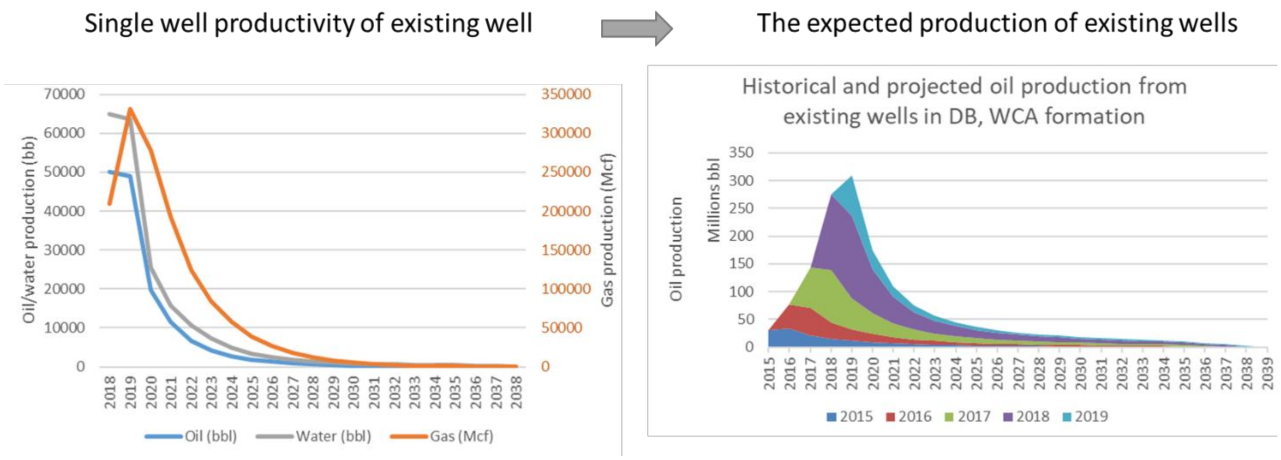


Figure 7-10 Single well productivity (type curve) of existing well, and its aggregated production over time

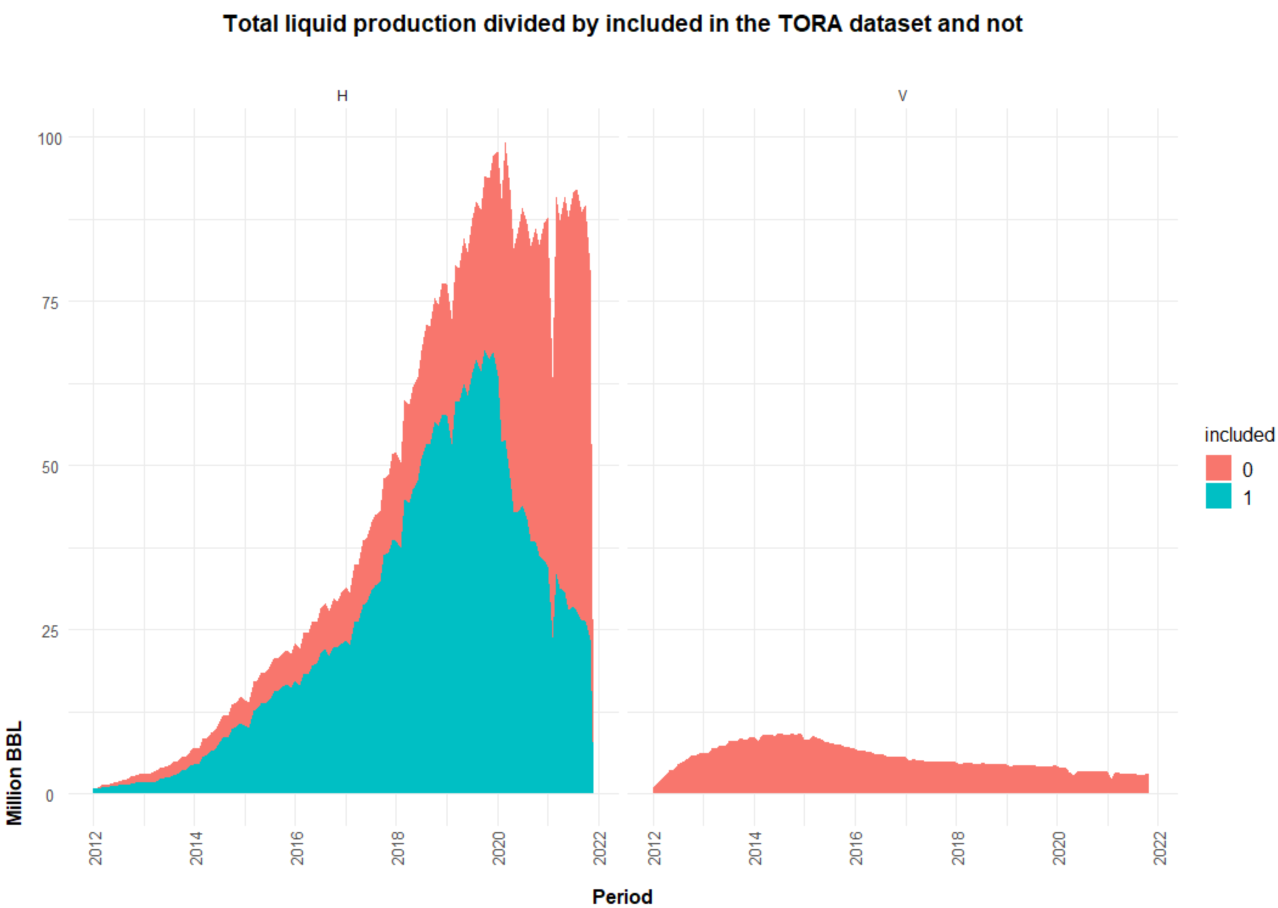


Figure 7-11 - Total crude production divided by TORA area versus non-TORA area

Figure 7-12 Total load requirement from existing wells by load type[5]

The second category of production presented in the forecasts is from future wells that were not yet drilled before 2021. For example, Figure 7-13 shows the expected drilling in the most prolific area like Wolfcamp A and B of the Delaware and Midland Basins of the TORA focused area, based on the perception of the future oil prices. Drilling activities indicate incremental wells being drilled each year.

[5] This does not include load for major gas pipeline.

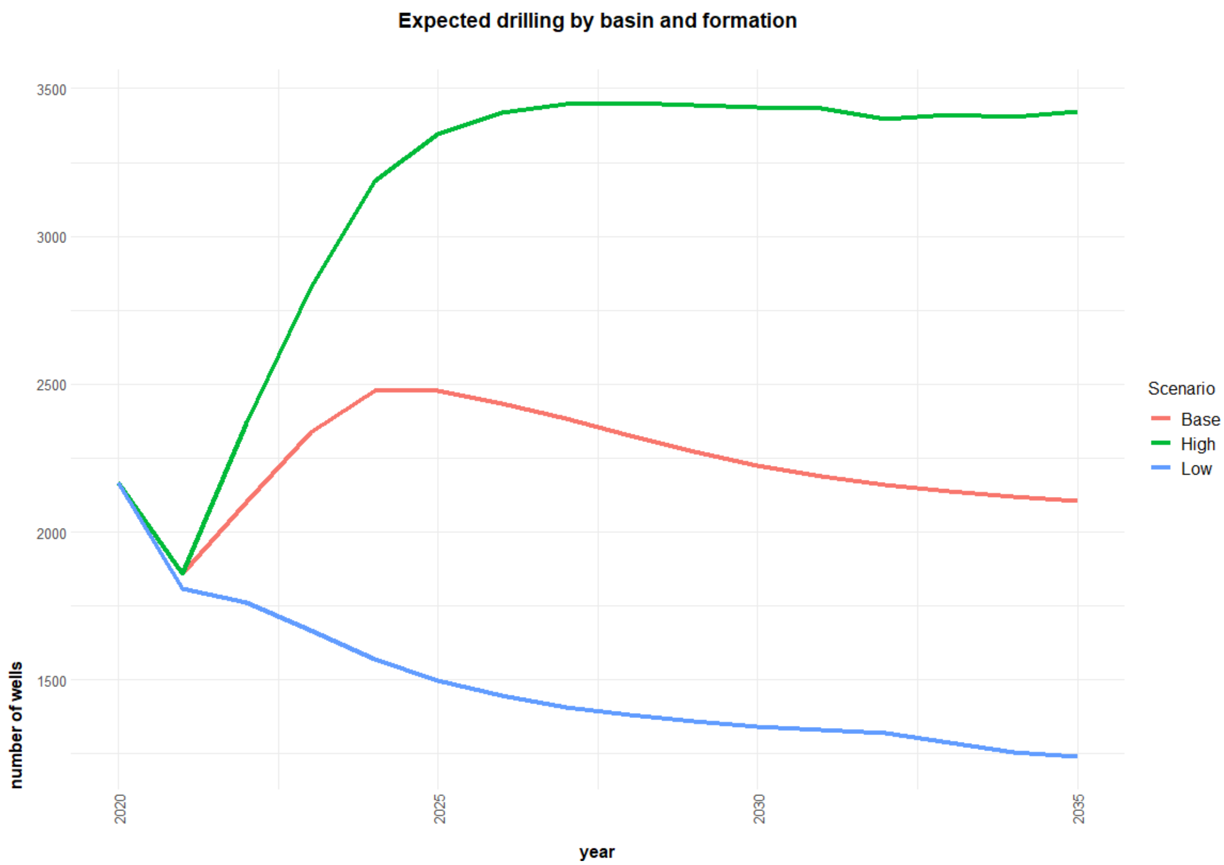


Figure 7-13 Expected drilling by the scenario in Delaware and Midland Basins (TORA focus area)[6]

[6] Number of wells drilled each year indicates the incremental wells.

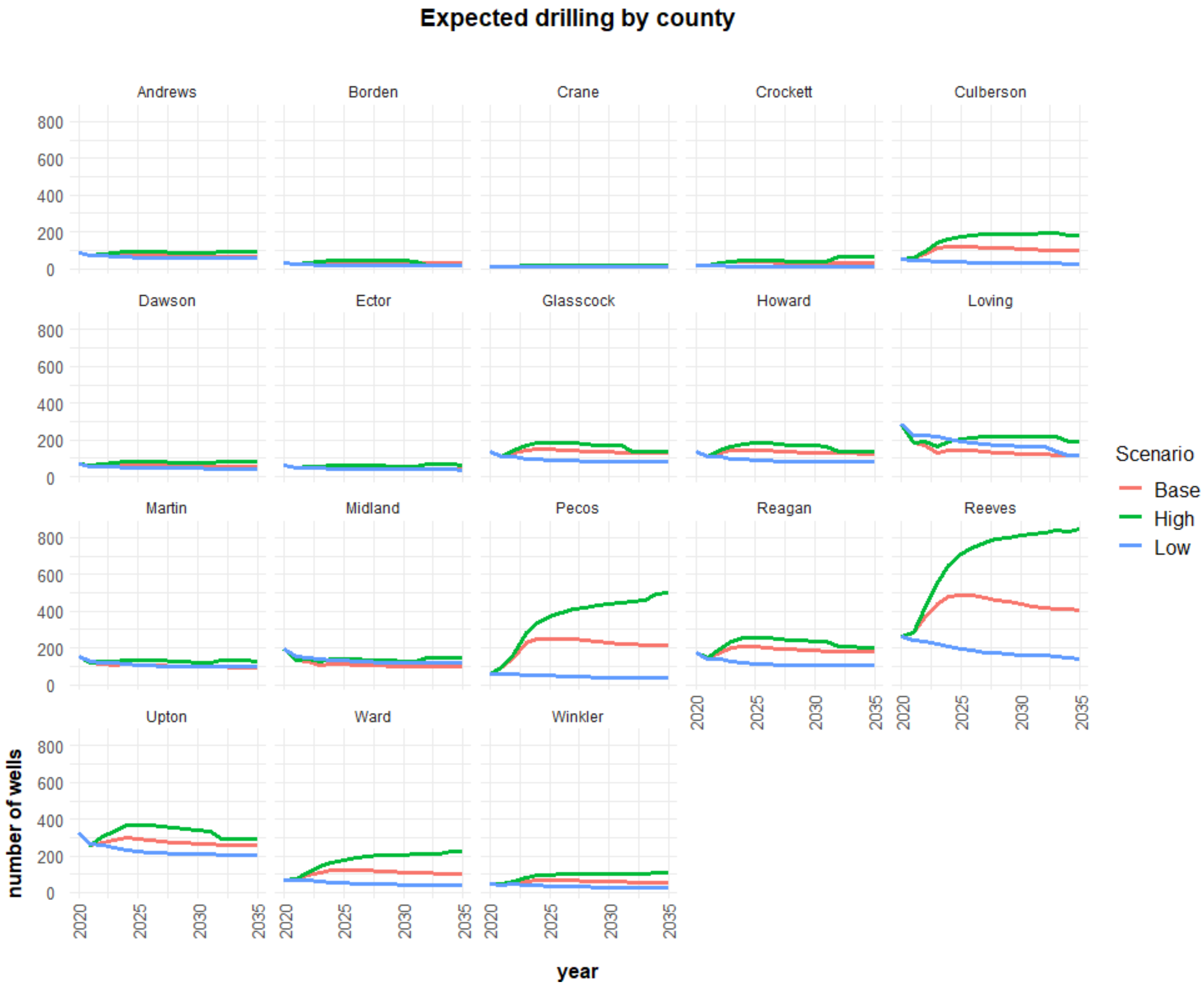


Figure 7-14 Expected drilling by county in the TORA area

Figure 7-14 shows the expected drilling by the county under each scenario in the TORA focused area. Here the scenario difference is mainly driven by price assumptions. It is important to note that Pecos county and Reeves county continue to have a strong growth of activities in the high price scenario, while some other countries have limited upside. The counties with higher upsides indicate that more wells may not be in the "sweet spot" of production that may become economical at a higher price. Of course, it is important to note that the number of wells drilled does not indicate the highest throughput of products. Therefore, we need to continue diving into the single well productivity in these expected drilling areas and calculate its expected productivity at the well level depending on its location.

For vertical wells, the methodology is similar. The drilling rate is estimated based on the trend of incremental vertical well drilling in historical data, with about 300 wells drilled per year since 2018.

The next step is to aggregate all the future well load requirements by scenario. With continuous drilling assumptions, whose intensity differs based on the price assumption, the drilling activities under each scenario result in different production levels and are impacted by the assumption of electrification of midstream pipelines (mainly for natural gas). With the higher price of oil, it is expected that there will be a higher level of drilling each year, leading to a higher level of production throughout the forecasted period. Higher electrification levels in the midstream sector imply more conversion from gas-fired turbines to electric ones for compressing and transporting gas, leading to a higher electric load on the grid, even with the same expected production throughput of gas. Figure 7-15 shows the aggregated load for future wells (excluding major pipeline load) for the study area[7].

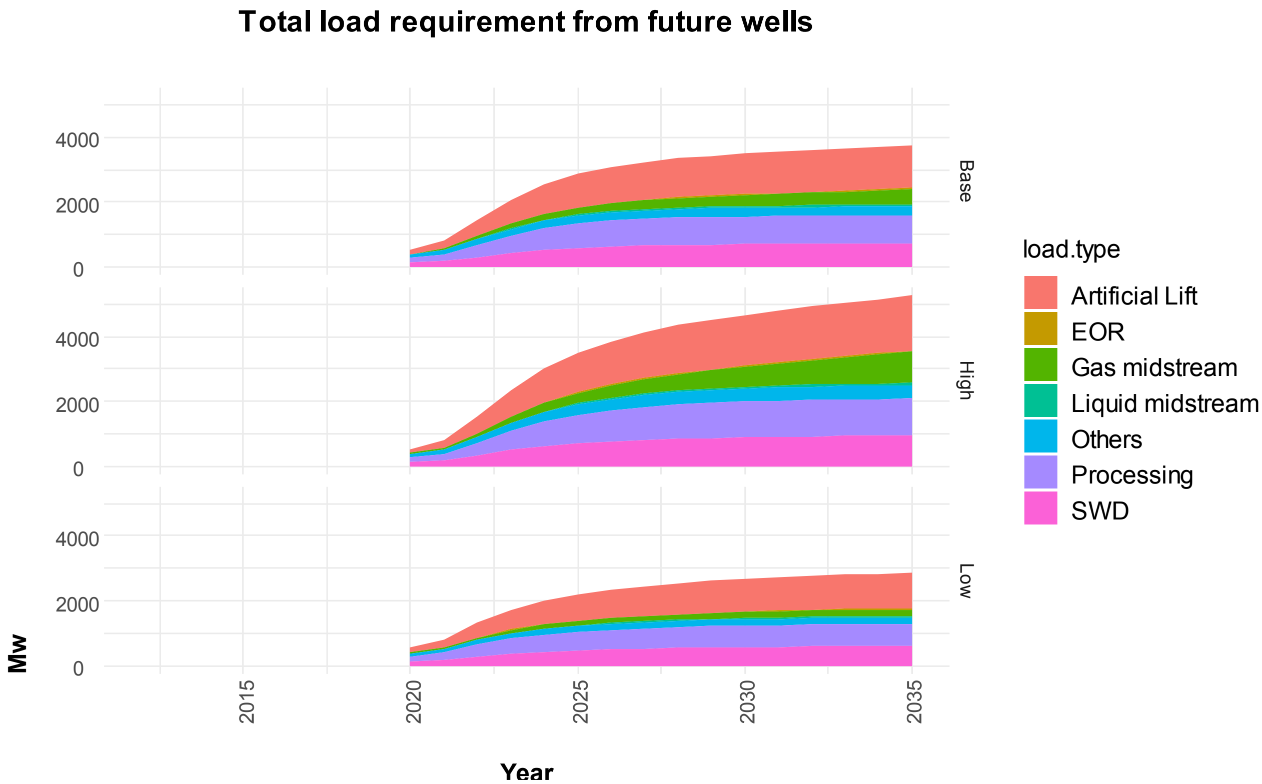


Figure 7-15 Total load requirement from future wells

In addition to the well based load requirement, the load requirement of major pipeline cross-county load, mainly for natural gas, is also included here based on the methodology mentioned in section 5.6. Combining existing and future wells production outlook with major pipeline load on the county level, Figure 7-16 and Figure 7-17 summarize the total load assessment from 2012 through 2035, with forecasts starting in 2021.

Here are some key observations from the results:

There was astonishing growth for 2015-2020, from 950 MW to around 3400 MW, with about a 29 percent annual growth rate. The growth of future load is described based on scenarios here.

The base scenario of $70 per barrel of oil remains a steady production level, increasing electrification by about 1.2 percent per year, converting 30 percent of the total midstream compression load by 2035. There is an increase over 60 percent, reaching 5682 MW assuming conservative drilling plans, where operators only rely on internal revenue without additional borrowing.

The high scenario of $90 per barrel of oil with 58 percent of electrification of midstream transportation by 2035, lead to higher drilling levels and production in the future and the higher converted load from midstream. The 2035 level of total load will reach 8951 MW, almost 2.6 times the level in the year 2020.

[7] Major pipeline load were not aggregated from well level, instead it is calculated based on county level.

The low scenario of $35 per barrel of oil, in the long run, will have a declining production with almost no growth and a status quo electrification level of around 10 percent. This scenario leads to a stagnant total load level in the study area, with mild growth in the forecasted period, peaking at 3800 MW and then declining slowly through 2035 to 3750 MW. This scenario combines the industry's most pessimistic and conservative assumptions to help provide a boundary scenario for the future load.

It is important to recognize that these three scenarios describe the range of possibilities for future estimated load in this area. The upside with the high oil prices and aggressive electrification efforts will fuel a high annual growth rate of 6.6 percent for the required load through 2035. The downside with low oil prices and no progress in electrification will maintain the current load level. In other words, this study concludes that the total load associated with oil and gas activities in West Texas is not likely to decrease over time, even in the most conservative setting.

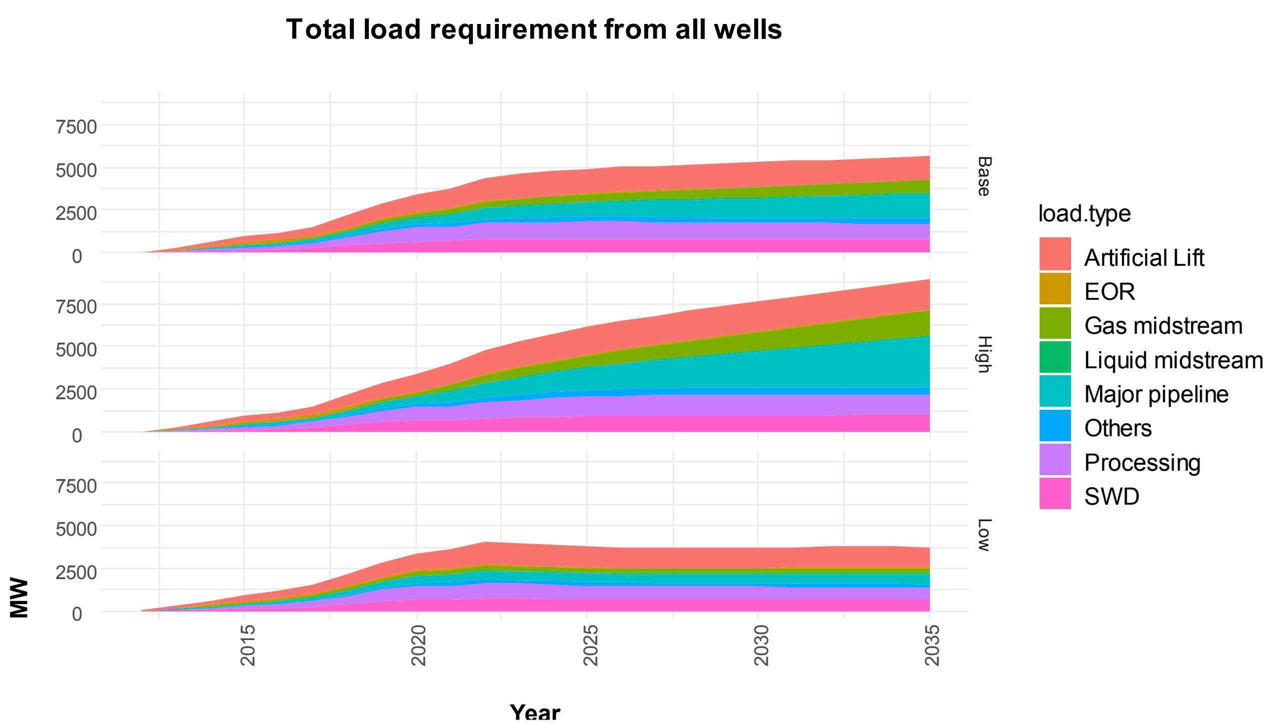


Figure 7-16 Total load requirements by scenario and by load type

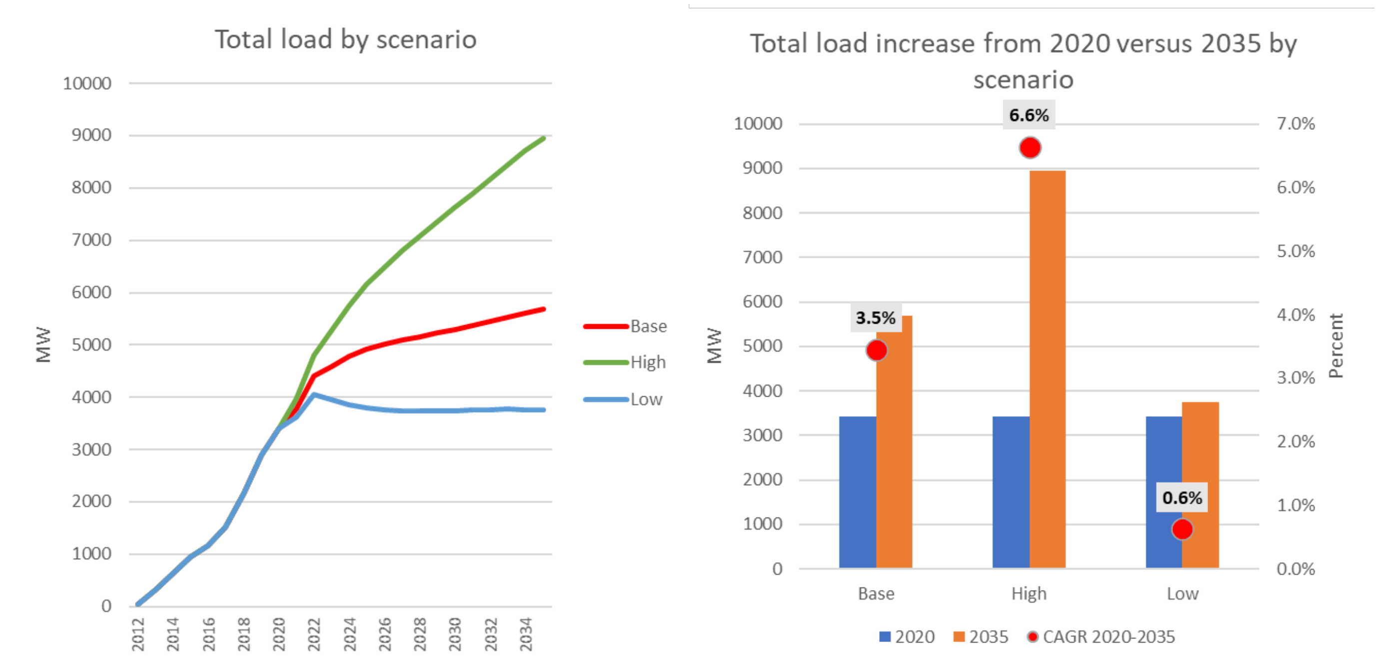


Figure 7-17 Total load requirement by scenario [8]

Figure 7-18 shows the total load assessment by county from 2012 through 2035. Reeves county continues to be the top county of production and load requirement in the forecasted period. However, there is slower growth in counties in the Midland Basin, indicating the expected increasing drilling activities in the Delaware Basin. It is noticeable that the scenario difference varies in magnitude for different counties. For Loving, Martin, and Midland counties, the difference between scenarios is fairly narrow, while there is a greater impact for Pecos and Reeves counties. Since those counties are mainly located in the Delaware Basin, it implies that Delaware Basin has more potential for load growth across the different conditions. In other words, there is a greater need for adding additional infrastructure to the grid in these counties with the highest load potential.

Furthermore, based on the type of activities, the breakup of load by type is also different by county. For example, Pecos County has one of the highest infrastructure networks of natural gas, including the Waha header hub, connecting to multiple major pipeline systems to transport gas out of the Permian Basin. Therefore, the cross-county pipeline flow on major pipeline systems is higher for Pecos County than other counties.

It is worth noting that all the load-requirement projections by county assume that most of the load related to oil and gas activities are occurring in the same county as its source of production. In reality, it is possible to have cross-country load occurrence. The later sections of this chapter will discuss the assumptions and their implications for locating the future loads in the forecasted period.

[8] CAGR: compounded annual growth rate.

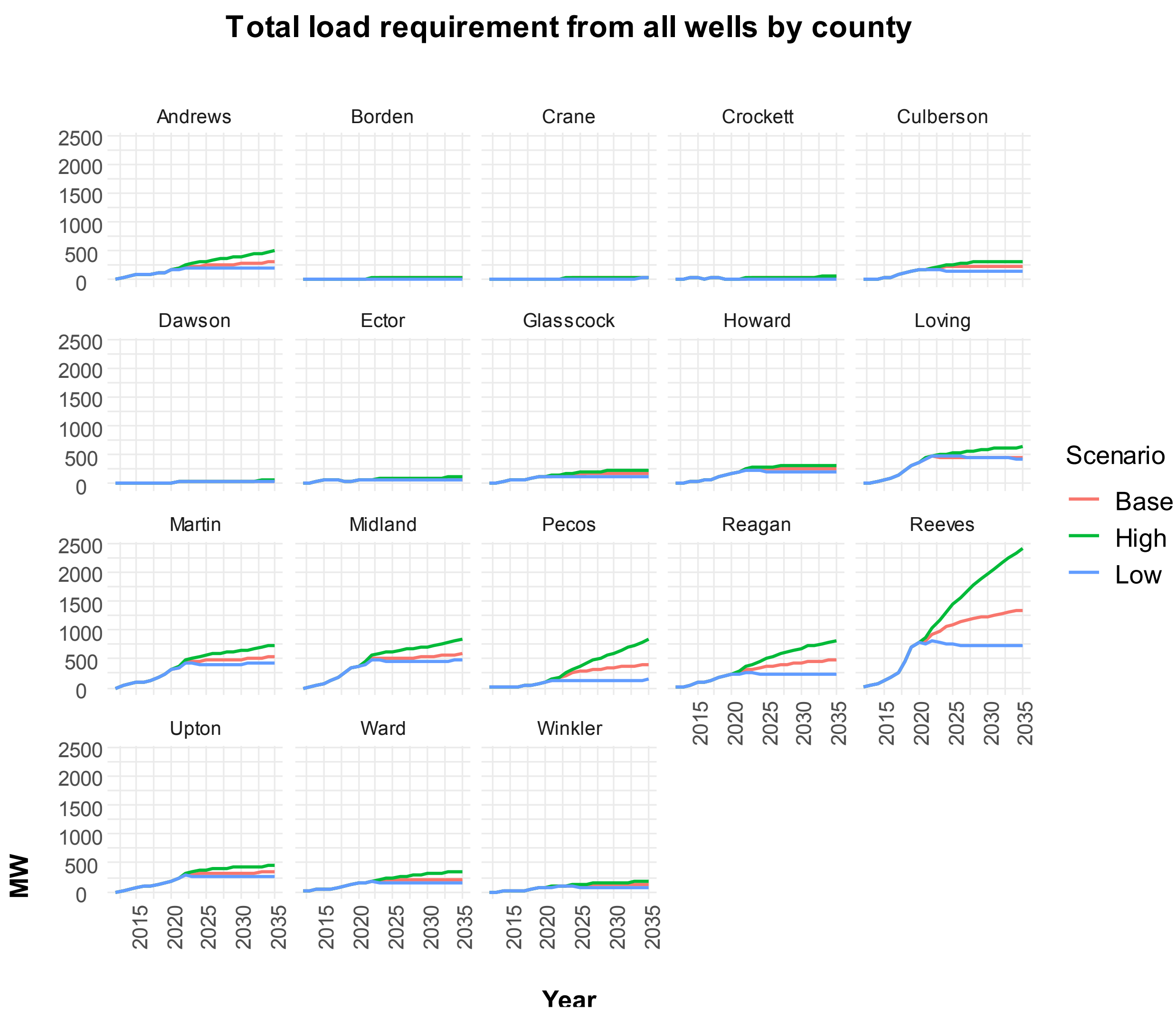


Figure 7-18 Total load requirement from all wells by county

Instead of looking at the aggregated impact, Figure 7-19 demonstrates a tornado chart of impacts between scenarios by load type. The chart shows the top load type that would drive the difference between scenarios: midstream gas transportation in both gathering and major pipelines, artificial list, and SWD injection. In the scenario set up of this study, we have selected three different electrification assumptions and three price scenarios. Therefore, there are dual impacts from prices and electrification on midstream load for natural gas.

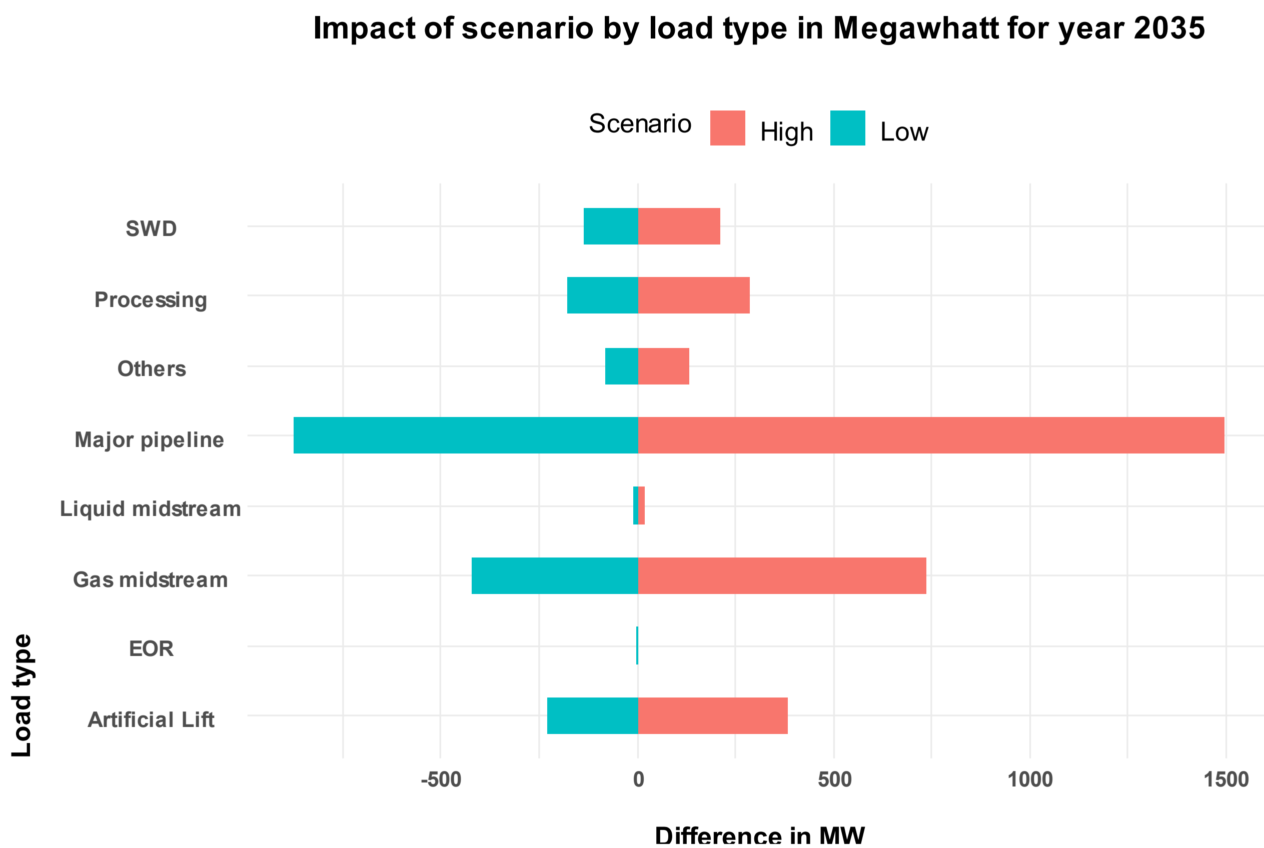


Figure 7-19 Impact of the scenario by load type for the year 2035

Recognizing that there are two drivers (oil price and electrification) for each scenario, the following analysis helps identify and isolate the impact of the two drivers on total load a bit further, shown in Figure 7-20. Each chart of the panel presents one single price scenario - low price ($35/bbl), base price ($70/bbl), and high price ($90/bbl). There are four different levels of electrification assumption, represented by the average annual growth rate from the year 2021 within each chart.

"Status quo" case – maintain the current 10 percent electrification with **0 percent growth**. This is used in the low scenario definition. A **1.2 percent annual growth** from 2021 to 2035 will reach around 30 percent of compressors' electrification used in the base scenario. A **3 percent annual growth** from 2021 to 2035 will reach around 58 percent (around 2/3) of the electrification of compressors, and this is used in the high scenario. A **5.5 percent annual growth** from 2021 to 2035 will reach around 97 percent of the electrification of the compressor and is used as an upper bound in this analysis to indicate the full electrification case. It is not used as a scenario assumption. In each chart, the particular electrification assumption picked for the scenario is highlighted in red with the black border of the area chart.

It is worth noting that the impact of electrification increases as underlying production increases, from the low price to high price scenarios. Taking the example of the year 2035 estimates, the range of outcomes is around 4400 MW of impact from 10 percent electrification assumption to 97 percent conversion in the low-price scenario. The range of outcome in high priced scenario grow to over 5600 MW of impact in the high-priced scenario, when comparing the estimated 2035 load under 97% electrification level versus 10% electrification level.

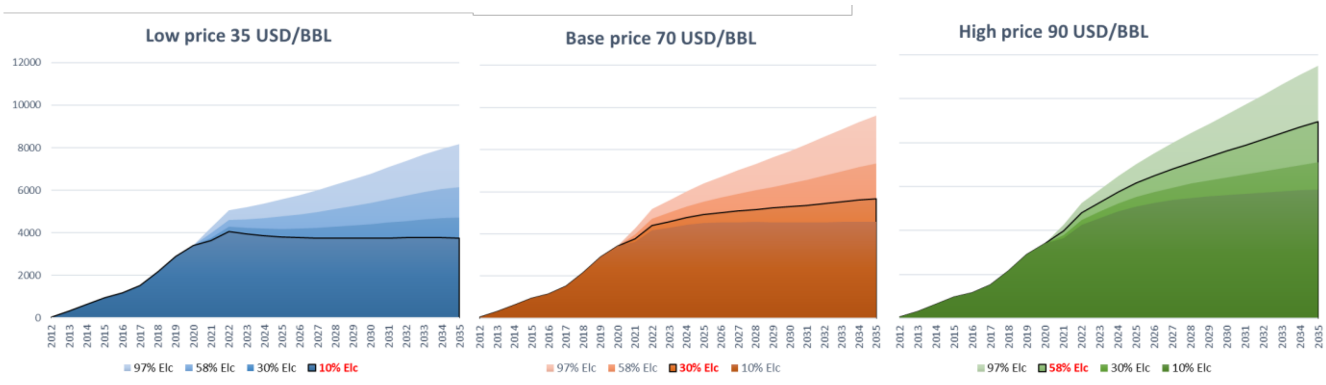


Figure 7-20 Sensitivity of load on price and electrification assumptions

7.4. Load heatmaps

It is also important to know where the load occurs for the forecasted period. The following section analyzes the location and volumetric relation of load in two steps. The first step is to map oil- and gas-related load to its location. The mapping load to location differs depending on the type of activities and availability of data. The second step is to discuss further the role oil and gas activities play in the aggregated load in West Texas via historical load from ERCOT as a reference of reported load in the region.

Although historical data could be mapped precisely to a point, forecasted data are presented in one-by-one square mile "blocks" in this study. For the consistency of the data, all mapping is done at the block level. A couple of factors would determine the methodology and assumption used in mapping, and the rest of the section discusses each type of activity separately. There are three types of mapping methods used in this study:

- The load impacts are near well sites for most upstream activities, which can be identified by either well location or presented at one-by-one mile blocks.

- The second impact category is mainly water disposal and midstream activities, which do not have granular and accurate locational information for the forecasted period. The specific challenges of data availability and rationales are covered already in previous chapters (Chapters 3 and 4). For those load impacts, an alternative solution is to map an approximate impact radius centered around producing well sites and based on historical average distances from well sites to the specific facilities, including compressor stations, pump stations, processing plants, and saltwater disposal sites. To study the locational relation of SWD to producing wells, we have mapped all producing wells to the closest two SWD facilities. The result shows that the disposal sites can be located anywhere between 2 miles to 20 miles from the producing wells.

- The last category of impact is on major transmission pipeline systems. The load impact is estimated at the county level and mapped based on potential locations of impact on existing infrastructure. These impact locations are no longer centered around production.

With the mapping methodology, the load for the entire study area is mapped one mile by one-mile block across the area with 27272 blocks, indicating its load impact locations. To provide a reference of history, Figure 7-21 shows the results of the load assessment by blocks in West Texas in the year 2020. Figure 7-22 shows the panel of heatmaps for total load in the year 2025, the year 2030, and the year 2035 by scenario. Here are some key observations:

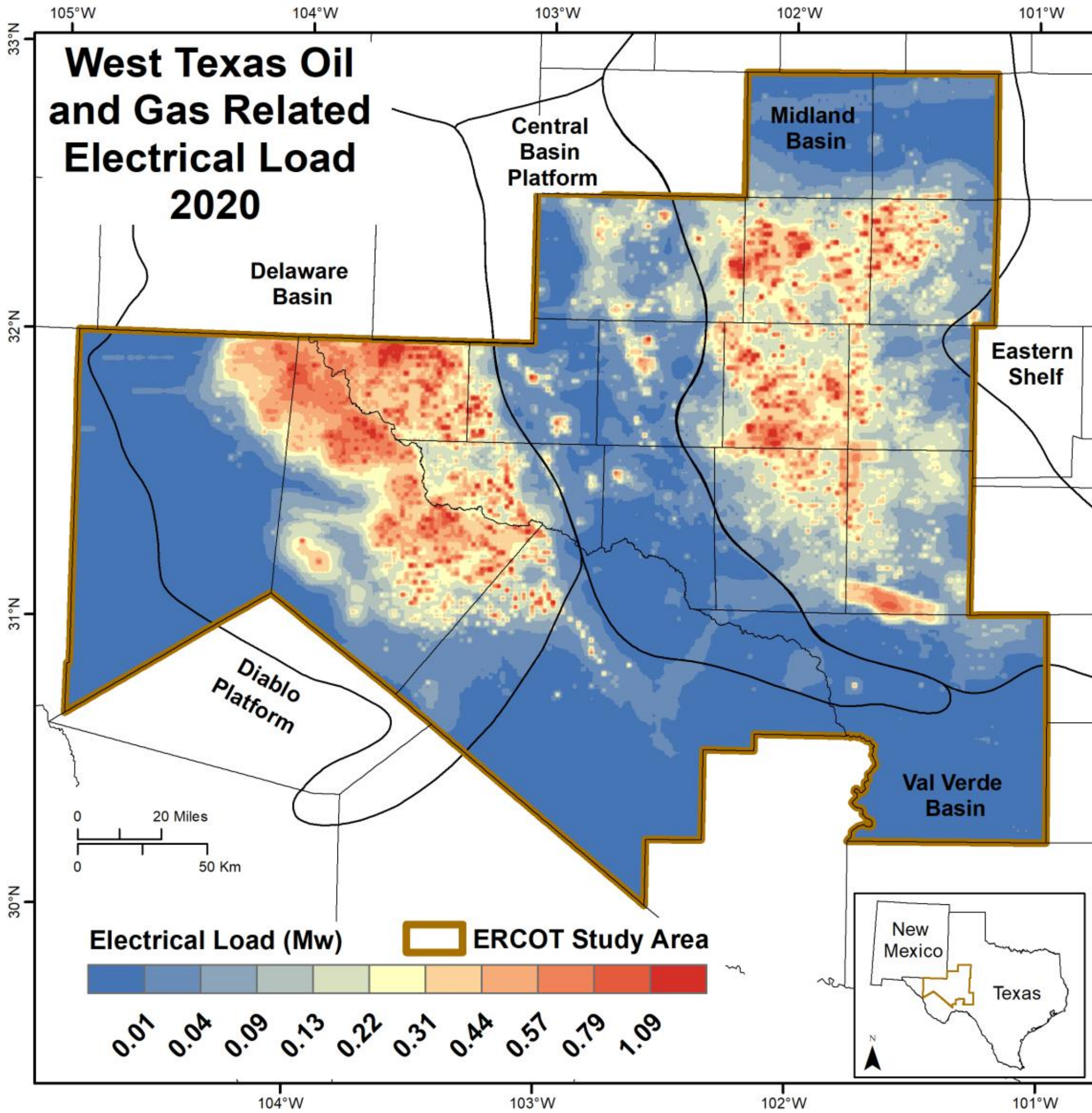


Figure 7-21 Heat map of electric load in West Texas in the year 2020

First, the areas with the most activities-related load are located in the sweet spot – the most prolific areas of the Delaware and Midland Basins. In contrast, the Central Basin Platform continues to have some additional load activities due to local vertical well production and some pipeline transportation load crossing the basin, especially delivering gas to the Waha hub located in Pecos County.

Second, the geographic coverage of electric load related to oil and gas activities grows for both Delaware and Midland Basins over the forecasted period, based on the forecasted drilling activities. It is easy to observe the intensified load by color in the maps of the high scenario of 2025, 2030, and 2035. Furthermore, it is worth noting that although there is almost no change in total load in the low scenario, with low oil price for the long-term and status quo in electrification, there are changes in the locations of load occurrences in both basins.

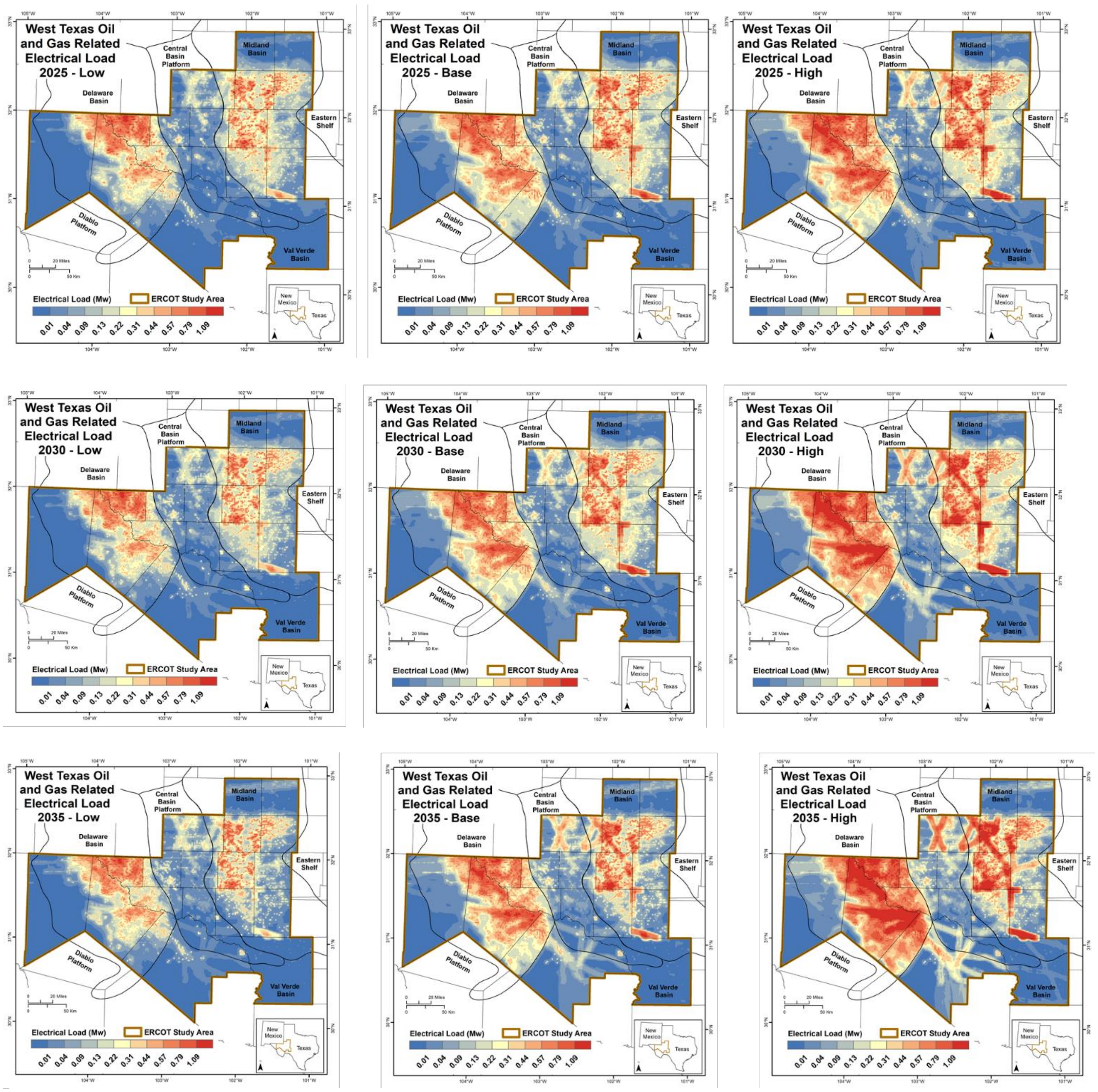


Figure 7-22 Heat map of electric load in year 2025 and year 2030 by scenario

Chapter 8. Conclusion and additional research

This study provides two major deliverables: first, a comprehensive analysis of load estimates related to oil and gas activities in upstream and midstream in the Texas portion of the Permian Basin; second, a detailed scenario-based load forecast, which can be mapped onto one square mile blocks, for the study area through the year 2035.

The major conclusions of the study include:

The projected growth of load in Permian is driven by a range of factors, including market conditions and a future trend in operation and regulation of emissions in the oil fields. It is important to recognize that additional factors drive the load growth in the next 10 to 15 years, along with the oil price, for Permian electric load, which is driven by the decarbonization efforts in the basin.

The study has effectively provided a robust method to identify the range of outcomes based on the defined scenarios. Besides estimating the aggregated load, this study also discussed the impact sensitivity with individual load types from oil and gas activities.

The scenarios described in this study cover two fundamental axes for the future: the market condition of the oil and the progress of decarbonization. The study concludes in March 2022 that the world oil price has increased to over 100 dollars per MMBtu, with a rise in natural gas prices in all markets. It is important to recognize that it is early to tell if that would be sustainable. Suppose this concern remains for the long-term, where what occurred in the year 2021 and early year 2022 becomes a norm, it would make the high scenario discussed here in the study more plausible, with a high oil price in the world, while a continuous progression in regulation on electrifications as part of the energy transition policies in the United States.

Furthermore, a few factors are not included in the current scope of the study, which may emerge in the future and require additional attention when ERCOT considers the load forecasts. For example, there is additional momentum of new projects that is worth monitoring:

Electric fracking: This study does not include any load that occurred during the fracking and drilling activities at the well site. The load required for fracking is significant but short-last (in weeks). Currently, fracking is supported by on-site generators instead of relying on the grid. This study assumes that the drilling and fracking continue to use on-site generation instead of the grid because it is challenging to accommodate these intense and short-term load peaks due to fracking operations. However, there are some indications from producers in the Permian that they are considering the electric fracking process as part of the strategy of further decarbonization efforts. The current momentum in electric fracking is slow, and it is worth monitoring its future development. The potential load impact could be significant on the grid.

Carbon Capture Utilization and Storage (CCUS): about 15 major carbon capture projects are expected to reach a final investment decision in 2022 around the world. Oxy's DAC-1, a direct air capture project in the New Mexico portion of the Permian Basin that would eventually capture1 million tpa of CO_2 emissions, is on the list. There are no major CCUS projects within the current study area for the ERCOT West Texas zone.

Blue hydrogen projects: Permian basins has the advantage of inexpensive associated gas production, which provides cost-competitive feedstock for blue hydrogen production. Blue hydrogen refers to splitting hydrogen atoms from natural gas, either by auto thermal reforming (ATR) or steam methane reformation (SMR), then preventing carbon dioxide (CO_2) emissions from being released. The emerging interests in leveraging Permian gas for blue hydrogen attract operators' attention to new investment opportunities.

In the current stage, there are no major projects of CCUS or blue hydrogen for the West Texas portion of the Permian.

However, it is plausible to expect additional projects from CCUS and blue hydrogen to emerge in the study area in the future.

Microgrids and distributed energy resources (DER) in oil field operation: A recently published study by the Joint Institute for Strategic Energy Analysis and the National Renewable Energy Laboratory (2022) studied the techno economics of renewable energy technologies colocating with oil production in the Permian Basin. The key conclusion is that only smaller renewable energy technologies (that generate 5 % of a site's load) are cost-optimal. Larger systems (that generate 50 % of the site load) offset significant amounts of CO_2 and present a negative net present value. It is also interesting to note that the assumption of industrial electricity rate for these facilities is relatively low in the study, around $0.03 per kilowatt-hour. In other words, these projects may be more profitable in counties with higher industrial electricity rates. In the interests of the current study, these microgrids and DERs projects may not be contributing much to the estimated grid load in the future, based on the current economics.

As oil and gas resources are expected to comprise a significant portion of the U.S. energy demand and economic output in the next decade, according to U.S. Energy Information Administration, additional attempts in decarbonization in the oil field would continue in the efforts to reduce the impacts on the environment and increasing operational efficiencies.

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Appendix

A. Oil pipeline power requirement

*linear interpolation algorithm: https://engineerexcel.com/bilinear-interpolation-excel/

3-inch Diameter [KW]

	Distance [miles]				
		0.1	1	10	100
Volume [bbl/d]	10	0.00564	0.00894	0.0156	0.029
	100	0.0565	0.0904	0.1670	0.403
	1000	0.582	1.07	3.27	20.3
	10000	15	103	954	9410

8-inch Diameter [KW]

	Distance [miles]				
		0.1	1	10	100
Volume [bbl/d]	10	0.00564	0.00894	0.0155	0.0287
	100	0.0564	0.0894	0.1550	0.289
	1000	0.564	0.894	1.58	3.1
	10000	5.73	11.5	25.2	126
	100000.0	114	669	5950	58300

20-inch Diameter [KW]

	Distance [miles]				
		0.1	1	10	100
Volume [bbl/d]	10	0.00564	0.00894	0.0155	0.0287
	100	0.0564	0.0894	0.1550	0.287
	1000	0.564	0.894	1.55	2.87
	10000	5.64	8.94	15.7	30.1
	100000	57.3	64.7	237	1120
	1000000	573	975	2380	11200

B. NGL pipeline power requirement

*linear interpolation algorithm: https://engineerexcel.com/bilinear-interpolation-excel/

3-inch Diameter [KW]

		Distance [miles]			
		0.1	1	10	100
Volume [bbl/d]	10	0.00282	0.00447	0.0078	0.0145
	100	0.02825	0.0452	0.0835	0.2015
	1000	0.291	0.535	1.635	10.15
	10000	7.5	51.5	477	4705

8-inch Diameter [KW]

		Distance [miles]			
		0.1	1	10	100
Volume [bbl/d]	10	0.00282	0.00447	0.0078	0.0144
	100	0.0282	0.0447	0.0775	0.145
	1000	0.282	0.447	0.79	1.6
	10000	2.87	5.8	12.6	63
	100000.0	57	334.5	2975	29150

20-inch Diameter [KW]

		Distance [miles]			
		0.1	1	10	100
Volume [bbl/d]	10	0.00056	0.00089	0.0016	0.0029
	100	0.0056	0.0089	0.0155	0.029
	1000	0.056	0.089	0.16	0.29
	10000	0.56	0.89	1.6	3.0
	100000	5.73	6.47	23.7	112
	1000000	57.3	97.5	238	1120

C. Gas pipeline power requirement

*linear interpolation algorithm: https://engineerexcel.com/bilinear-interpolation-excel/

3-inch Diameter [KW]					
	Distance [miles]				
		0.1	1	10	100
Volume MCFD	10	0.21110	0.21110	0.3180	0.557
	1000	0.6550	1.4800	6.5300	31.600
	10000	49.100	352.00	767.00	1380.0
	100000	10300	40600	56700	174000

8-inch Diameter [KW]					
	Distance [miles]				
		0.1	1	10	100
Volume MCFD	10	7.36	7.36000	7.4200	7.480
	1000	58.90	58.9000	59.4000	60.000
	10000	552.00	552.00	563.00	598.0
	100000	4360	4640	6150	10600

20-inch Diameter [KW]					
	Distance [miles]				
		0.1	1	10	100
Volume MCFD	100	7.36	7.36	7.42	7.48
	1000	58.9	58.9	59.4	60.0
	10000	552	552	557	563
	100000	4320	4320	4400	4710

D. Table of Figures