West Texas Forecasted Load Additions: Permian Basin –

Oncor Electric Delivery Company LLC

April 6, 2020

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Executive Summary

Introduction

Oncor commissioned IHS Markit to perform an independent study to determine the future power needs associated with the recent and ongoing growth in oil and gas activities in 24 counties within the Permian Basin of West Texas (Figure 1-1). This study was designed to provide a bottom-up analysis of electric load based on oil and gas industry intelligence, equipment requirements, and market dynamics. In this study, IHS Markit forecasts that the electricity needs of the Permian Basin will nearly double by 2030, based on a detailed examination of the key drivers underlying power demand in the Midland Basin, Delaware Basin, Central Basin Platform, and Fringe regions of the Permian Basin.

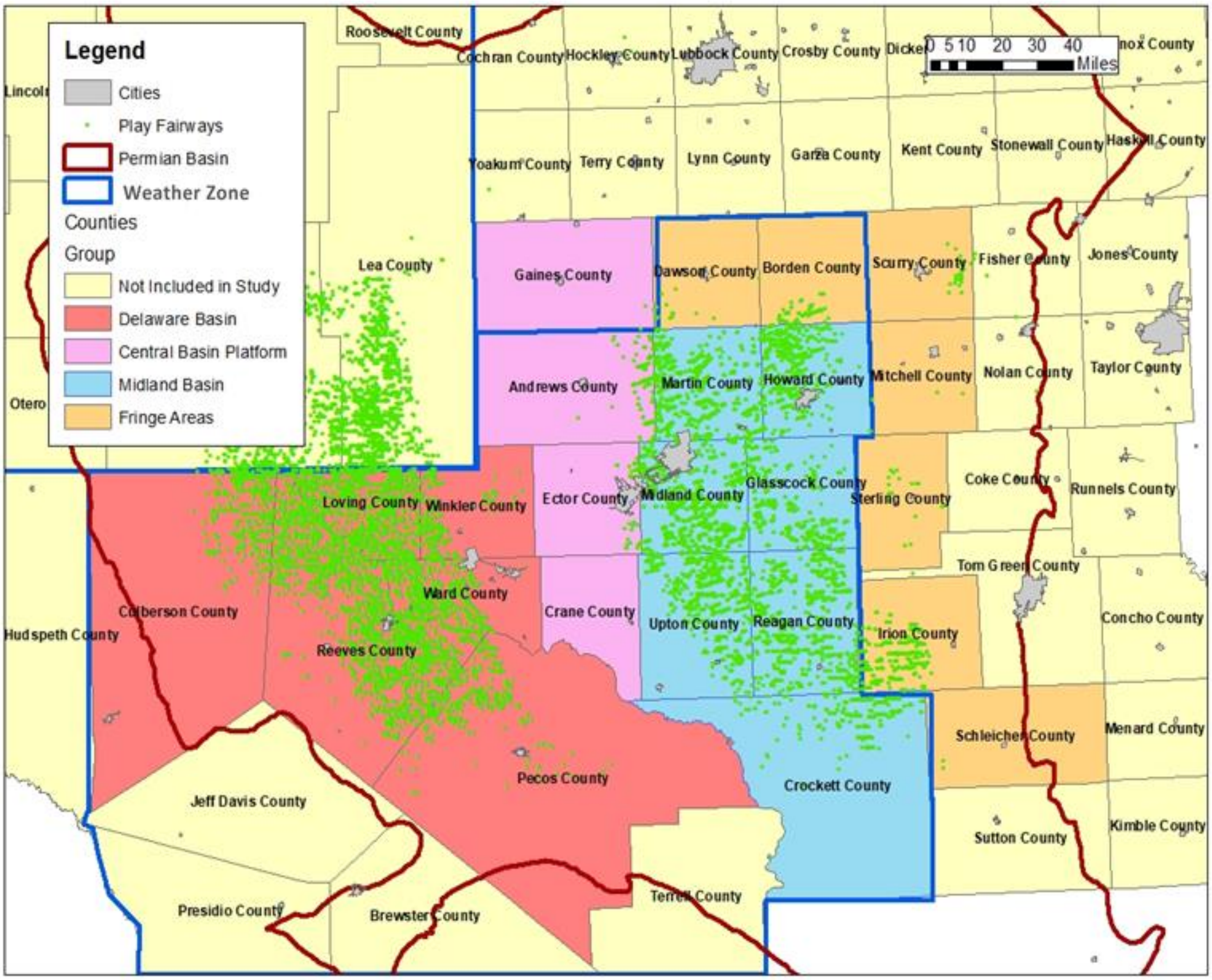

Figure 1-1. Map of the Permian Basin, outlining regional groups and counties included in the project scope

Summary of Findings

The Permian Basin region of Texas will continue to require dramatic increases in electrical power over the next decade. This is due to the vast mineral resources available for extraction at extremely economic levels. The Permian Basin enjoys some of the lowest break-even price levels for oil and gas production in the country, incentivizing producers to invest and develop the Permian Basin resources heavily now and into the future even if investment is flat or declining in other regions. Notably, IHS Markit expects long term growth in the Permian Basin to continue even with oil and gas prices at relatively low levels.

As the industry further develops these resources, so will the need for electricity increase. This is especially true given that there are substantial portions of the Permian Basin today that have no access or limited access to grid power. Most notably, today the most profitable area of oil and gas development in the Permian—the Delaware Basin—has the lowest access to grid power at only 61% of existing load being served from the electric grid. By 2030, IHS Markit assumes that 97% of Delaware Basin demand will have access to the electric grid, similar to the more mature Midland basin. Total electric load in the Delaware Basin is also expected to increase nearly 300%. In 2030, IHS Markit anticipates that electric load for the full 24 county area studied herein will nearly double as oil and gas activity is forecasted to increase in both the Delaware and Midland Basins.

Conservative Assumptions

The analysis was highly complex and relied on information obtained from industry interviews, public information, and internal sources. Competitively sensitive information is not readily available of course, and therefore, a certain number of assumptions must be made based on models and general industry standards.

Upon presenting initial findings to a combined gathering of ERCOT Market Participants and oil and gas company representatives, IHS Markit received feedback from several oil and gas companies expressing concerns of understatement of power demand related to certain oil and gas related operations. IHS Markit acknowledged these concerns as valid, but indicated that electrical use assumptions are intentionally skewed towards the conservative end of the range of possible outcomes to avoid inadvertently over-forecasting the power demand. These conservative assumptions include the following:

- Delayed use of Electric Submersible Pumps (ESPs) for artificial lift by assuming longer duration of natural lift and gas lift of a well's production when production is greatest.
- Pump efficiencies held constant, despite the fact that efficiency per unit of liquid flow decreases over time.
- All water production presumed disposed of into the historically used but shallower San Andres Formation utilizing low-horsepower high-efficiency pumps. This ignores the higher power demand required for: less-efficient pumps, enhanced oil recovery, and the need to utilize deeper, higher pressure water disposal sites such as the Ellenberger Formation.
- Electrical fracking and electrical rigs excluded from forecast, although some operators indicate that they are beginning use of electric rigs to drill wells and electric pumper units (or frack spreads) to perform hydraulic fracturing ("fracks"), and they prefer to use electric equipment where they have grid access (which will increasingly be available).
- Long-haul gas pipelines are assumed to be powered by gas turbines, which use 1 to 1.5% of the transported gas for fuel, rather than directly from the power grid.
- NGL pipelines being on the grid, but having only about 10% of the overall power requirements of long haul oil pipelines.
- Gas processing plants individually assessed on maps, and only those plants with clear access to the electric grid counted as being served by the grid.
- Excluded electric grid distribution losses of approximately 4%, and all loads were assumed to have a unity power factor and are expressed in watts only, without consideration for reactive load (vars), which also utilizes transmission and distribution capacity.

The combined impact of these conservative assumptions results in a greater probability of an under-forecast, rather than an over forecast of future power demand in the Permian Basin.

Report Roadmap

In Part 1 of this report, we discuss our analysis of the historical oil and gas activities and historical industrial activities in the Permian Basin. Through this analysis, IHS Markit determined that in 2019, TDSPs provided 79% of the total actual power requirements for oil and gas activities in the four regions of the Permian Basin, with the greatest shortage in the rapidly expanding Delaware Basin region, which is currently serving 61% of demand (Table 1), as noted above.

Part 1 also describes how IHS Markit developed an oil and gas production forecast for the Permian Basin and allocated that forecast to the individual county level to forecast the necessary power demand for each county. The forecast reflects the following:

Group	2019 O&G Activities (MW)	Oncor Billing Last 3 months 2019 (MW)	% On Grid - 2019 Avg (MW)
Delaware	1,640	993	61%
Midland	1,322	1,269	96%
CBP	695	668	96%
Fringe	438	393	90%
Total	**4,095**	**3,223**	**79%**

- Low break-even levels for unconventional resources that will continue to incentivize drilling activity in the Permian Basin as many of its core areas remain profitable at oil prices below $50 a barrel, with operators in some areas achieving break-even levels below $35 a barrel.

- Low break-even prices, expansive drilling opportunities, and the elimination of pipeline bottlenecks in the region, which will cause operators to move away from higher cost areas and focus their operations in the Permian Basin.

- Undeveloped unconventional resources that include 78.7 billion barrels of oil, 15.8 billion barrels of natural-gas liquids (NGLs), and 239 trillion cubic feet of natural gas will provide ongoing opportunities for economical oil and gas development in the region for at least the next decade and beyond.

- Permian daily oil production that will reach 8 million barrels per day by the end of 2030 – nearly a 60% increase from 2019 levels. Forecasted water handling associated with the oil production will also increase at an even faster rate.

- Constant year-over-year increases in industrial peak power demand, driven by the influx in oil and gas development that will grow from a current peak demand rate of approximately 3,600 MW to approximately 8,700 MW by 2030.

- Coincident peak load for combined industrial, residential and commercial sectors within the 24 counties included in the study will approximately double by 2030, increasing from about 5,160 MW at the peak of 2019 to about 10,180 MW in August 2030.

- By 2030, the industrial portion of peak power demand will comprise about 86% of the total 10,180 MW of all peak power demand, which is an increase from the current 70% of the total 5,160 MW of all peak power demand.

Part 2 of this report describes the county-level forecasts IHS Markit developed and the associated oil and gas operations, which included upstream (production, separation and water handling activities) and downstream (processing and transportation of oil and gas prior to market) activities. It also describes the various oil and gas activities that require electrical power, relates these activities to production and drilling historical data at the county level, and describes the methodologies used to quantify power usage for each activity. Through this analysis, IHS

Markit established relationships between specific oil and gas activities and documented power requirements of those activities. This analysis reveals the following:

- The mature fields in the Central Basin will experience gradual decline in the years ahead, even as power demands remain constant, while the Midland and Delaware basins will experience rapid, ongoing development between the years 2020 and 2030.
- Increasing water to oil ratios (WOR) will drive liquids production in the long term and will increasingly contribute to overall power demand as wells mature.
- While electric power from the grid is the most cost effective and more reliable option, many operators currently rely on on-site generators to power their equipment and facilities but would prefer, and are entitled to receive, electric-grid service.

In Part 3 of this report, IHS Markit builds on the analysis presented in Part 2 by comparing, within each of the 24 counties, historical power usage to the actual power demand of oil and gas related activities to validate the calculated power usage against real historical data, determine to what extent oil and gas operations are on the electrical grid within each of the counties, build a power demand forecast at the county level by applying these comparisons, apply appropriate load factors to calculate peak coincidence, and integrate the county-level power forecast with current and projected oil and gas activities. Also included are a set of maps with one-mile grids showing where load demand is most likely to occur in 2-year increments over the forecast period. Results obtained for each county are rolled up to the region and basin level. This analysis demonstrates that:

- Industrial power usage grew strongly, from less than 2,000 MW in early 2016 to approximately 3,400 MW by the end of 2019.
- Over that four-year period, Oncor has provided service for over 70% of total power usage.
- By the end of 2019, Oncor provided almost 2,500 MW of the 3,400 MW total estimated average industrial power usage within the 24 counties.
- Power demand has been, and will remain, stable in the Central Basin Platform and Fringe areas of the Permian Basin. However, the Delaware and Midland basins are experiencing rising power demand, driven by the steadily rising industrial loads due to ongoing and forecasted increases in oil and gas activity.
- Industrial loads in the Permian Basin will continue rising substantially over the next 10 years, with a majority of this rise attributable to the Delaware Basin, where peak demand is projected to increase from ~1,100 MW to ~4,800 MW, and the Midland Basin, which will see an increase from ~1,300 MW to ~2,500 MW by 2030.
- Only 61% of operations in the burgeoning Delaware Basin currently rely on grid power. This is far less than the more mature fields in the Midland Basin, and Central Basin Platform, and Fringe regions, where the on-grid percentage ranges from 90% to 97%.

Part 4 of the report presents the methodology that IHS Markit used to develop the Permian Basin total power demand forecast, including the methodologies for residential energy and peak demand forecasts and commercial energy and peak demand forecasts, and the associated econometric modeling. IHS Markit utilized a “top-down, bottom-up” forecasting approach for residential and commercial load, which focuses first on the internal growth dynamics of an area before linking the area model to a national system. This allows for more accurate forecasting than most previous multi-regional forecasting efforts, which have tended to describe a region’s growth as a proportion of the projected total for the U.S.

1 Permian Basin Forecast and Fundamentals

1.1 Introduction

Oncor Electric Delivery Company, LLC ("Oncor") is the largest electric delivery company in the State of Texas with over 16,000 miles of transmission lines located throughout the western portion of the state. Due to the recent and ongoing expansion of oil and gas production from the Permian Basin of West Texas, Oncor retained IHS Markit to assess the need for additional electrical infrastructure capability within this area.

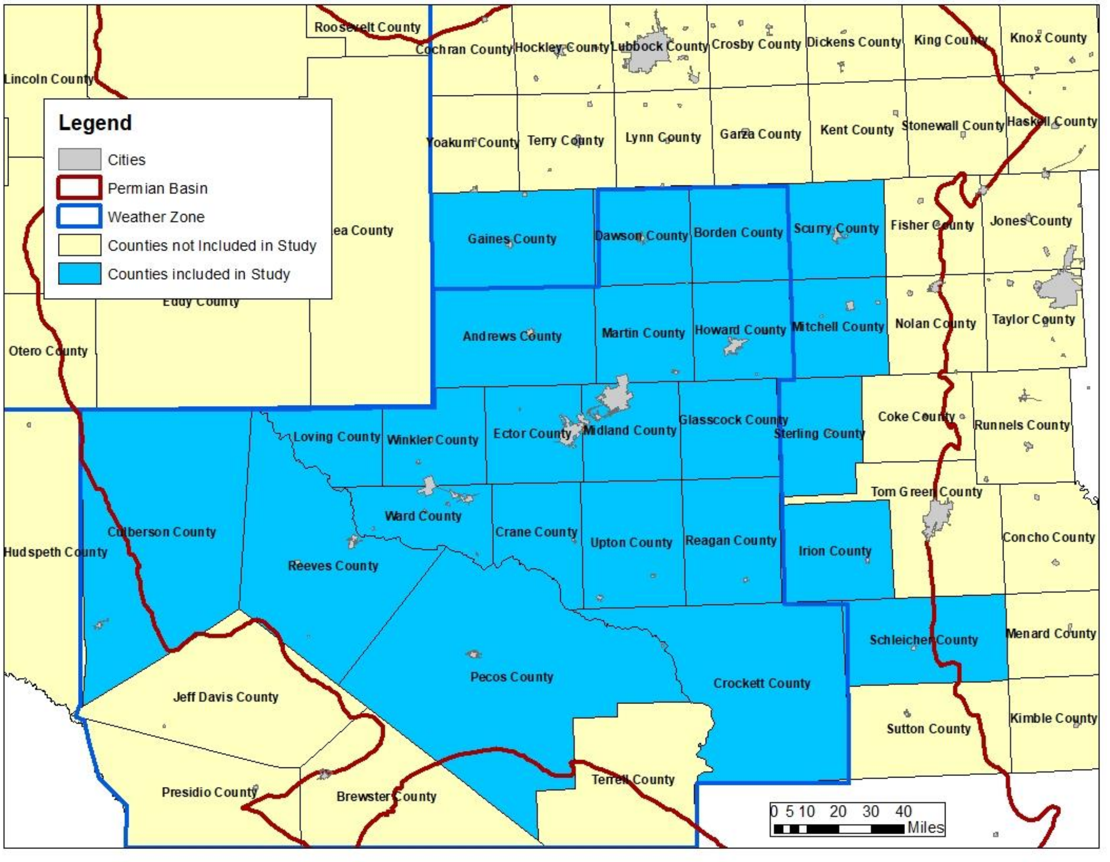

Figure 1-1. Permian Basin map, with regions – includes far west weather zone and 6 adjacent counties

Over the past several months, IHS Markit and Oncor have been working together to facilitate the completion of this study. Oncor has supplied to IHS Markit (subject to a non-disclosure agreement) historical electric load and distribution information, which has been integrated with IHS Markit proprietary data, information, analysis, and research to produce the results of the study. IHS Markit and Oncor have also reached out to oil and gas industry sources and contacts to further enhance and validate study assumptions and methodology. Our goal has been to employ a data-driven analytical process to generate a forecast of future power demand tied to specific locations within the Permian Basin of West Texas. While the bulk of the analysis has been focused on the use of industrial power related to oil and gas operations, applicable commercial and residential forecasts are also included in order to complete the overall load forecast.

This report will describe and summarize the results of the study, as well as describe the assumptions, data and data sources, methodologies and analysis that underlie the conclusions. While the report addresses the overall Permian Basin, the bulk of the analysis specifically focuses on 24 counties, most of which are in the Far West Weather Zone (figure 1-1). We also assess additional residential and commercial power needs for the region and at the county level. The various parts and chapters of this report will detail the steps and approaches which underlie the forecast and will provide basin-wide and regional results and conclusions. This includes the following:

- A regional overview of the Permian Basin; an oil and gas production forecast and key drivers underlying that forecast which serves as a foundation for the entire study,

- A determination of key oil and gas operations (both upstream and midstream) that require power usage, and to what extent these are being employed in each county and throughout the basin.

- A historical perspective and forecast of industrial power demand related to oil and gas operations, which includes matching of historical load data (which includes public data and data supplied by Oncor) with actual oil and gas power usage at the county level and projecting future industrial power demand. A section showing highly granular one-mile gridded areas where we believe future industrial power demand growth related to oil and gas activity is also included,

- A forecast of total future power demand, including residential and commercial demand, which is included along with the industrial power demand

Near the end of the report are summary analysis and forecasts for each of the 24 counties included in the study, which describes the entire process undertaken to generate these individual forecasts for each county.

1.1.1 Findings

- While we expect to continue to see modest year over year increases in oil production from the Permian Basin, industrial power demand will grow at a much faster rate. Along with production increases, other drivers include interconnecting oil and gas operations not currently connected to the grid, increased associated gas gathering, compression, and increased water production and disposal related to all oil and gas operations.

- Overall, we forecast that the coincident peak load for industrial, residential and commercial sectors within the 24 counties included in the study will approximately double by 2030, increasing from about 5,160 MW at the peak of 2019 to about 10,180 MW in August 2030. The approximately 4,300 MW in August 2019 as reported by ERCOT in the Far West Weather Zone is less than the 5,160 MW; however, there are six counties in this study area that lie to the east and north of the Far West Weather Zone with significant oil and gas activity. In August 2019, industrial demand accounted for 3,617 MW or about 70% of the coincident peak load, while at the end of the forecast period in 2030, industrial demand will account for 8,725 MW or about 86% of the total peak demand.

- In the base case, total undrilled resources reach 78.7 billion barrels of oil (Bbbl), 15.8 billion barrels of Natural Gas Liquids (NGL), and 239 trillion cubic feet (Tcf) of gas. About 80 to 90% of the future locations have yet to be drilled with less than 10% of the future production being Proved Developed Producing (PDP) reserves.

- Because the Permian Basin plays have the lowest breakeven prices and highest number of drilling opportunities (compared to other North American unconventional plays), IHS Markit expects that operators will consolidate their operations to focus on the Permian Basin, while moving out of or cutting operations in higher cost areas such as the Bakken (North Dakota), Eagle Ford (South Texas) and STACK (Oklahoma) unconventional plays.

- Permian Basin oil production is expected to reach 8 million barrels per day by the end of 2030 – nearly a 100% increase from the 2019 levels. Of that portion, about 5.8 million barrels per day will be from the Texas portion of the basin.

- The pipeline capacity emerging out of the Permian appears enduring, removing significant risk of further in-basin bottlenecks or basis blowouts for the foreseeable future. In total, at least 3.7 million barrels per day (bbl/d) of new capacity is already operating or planned by 2021.

- New drilling in the Permian Basin will outpace the natural declines in production which have been increasing in recent years. The growth spurt from 2017 through 2019 has pushed base decline rates for the onshore system to record levels in both absolute (about 3.5 MMbbl/d) and percentage (about 35%) terms. Overall, we expect the base decline rates of the Permian Basin to moderate from 2020-2023, dropping below 40%. This will allow for moderate growth in net production at West Texas Intermediate (WTI) prices in the mid-$50’s by the early 2020s.

- While there is uncertainty in any oil or gas price forecast, most experts, including IHS Markit, agree that the price will remain above $50/bbl (in real terms) throughout the initial forecast period. As far as gas resource is concerned, this means that oil will drive the gas production forecast and given the high Gas Oil Ratios (GOR), particularly in the Delaware Basin, we can expect that low-cost to no-cost gas will continue to flow from the Permian Basin.

1.2 Permian Basin Oil and Gas Outlook

1.2.1 Summary outlook

The IHS Markit real WTI price forecast calls for crude oil prices to remain in the low $50s through 2022, with a gradual escalation thereafter until the price reaches $65 per barrel (in real dollars) in the late 2020s. After several years of million barrels per day growth annually in US production, we expect the growth to slow to about 440,000barrels per day in 2020, followed by a similar growth rate in 2021.

It can be said that 2019 marked the oil and gas industry transition to a new business model which de-emphasizes growth as investors are urging producers to yield higher returns. While IHS Markit supports the general view that producers would need a sustained WTI price above $65 to defy investor demands, it believes that prospective opportunities capable of generating a healthy rate of return will continue to attract investments, despite the apparent realignment of priorities. From this perspective, the Permian region is projected to become the primary target for future upstream tight oil investments. IHS Markit projects that vast and relatively low-cost resources of approximately 78 billion barrels of oil remain to be produced in the Permian Basin, much of which will be developed through 2030.

The $50–70 per barrel oil price level is still adequate to incentivize drilling activity in the basin. The cost to develop unconventional oil resources has declined significantly since the oil price collapse of 2014–2016. IHS Markit estimates that most of the long-term growth in North American unconventional resources can be supplied at $65 or below.

For the foreseeable future, the Permian Basin will likely continue to be the worldwide swing producer, but the output should continue to grow along with expected worldwide demand. The unconventional plays in the Permian Delaware region will be responsible for over 85% of the total Permian production by 2030.

Many of the Permian Basin core areas that are described below remain profitable below $50/bbl. A majority of the Bone Spring play’s inventory requires a $45/bbl WTI price, and very few wells in the Wolfcamp Delaware play are uneconomic at $50/bbl. Likewise, many of the Permian Midland Basin wells have strong economics, with the most productive and economic wells located in the Northern Midland basin, where operators achieve break-even prices below $40/bbl for a majority of their wells.

New pipelines have debottlenecked the Permian Basin and Cushing, which should keep the Brent-WTI spread narrow for the foreseeable future.[1] Large diameter pipelines out of the Permian have begun flowing, providing Permian barrels more direct access to the Gulf Coast and international pricing than barrels sold in Midland or Cushing. Meanwhile, this more competitive situation has led pipelines to cut tariff rates to attract customers. These dynamics have dramatically reduced the price differential (or penalty) between Midland/Cushing and Houston.

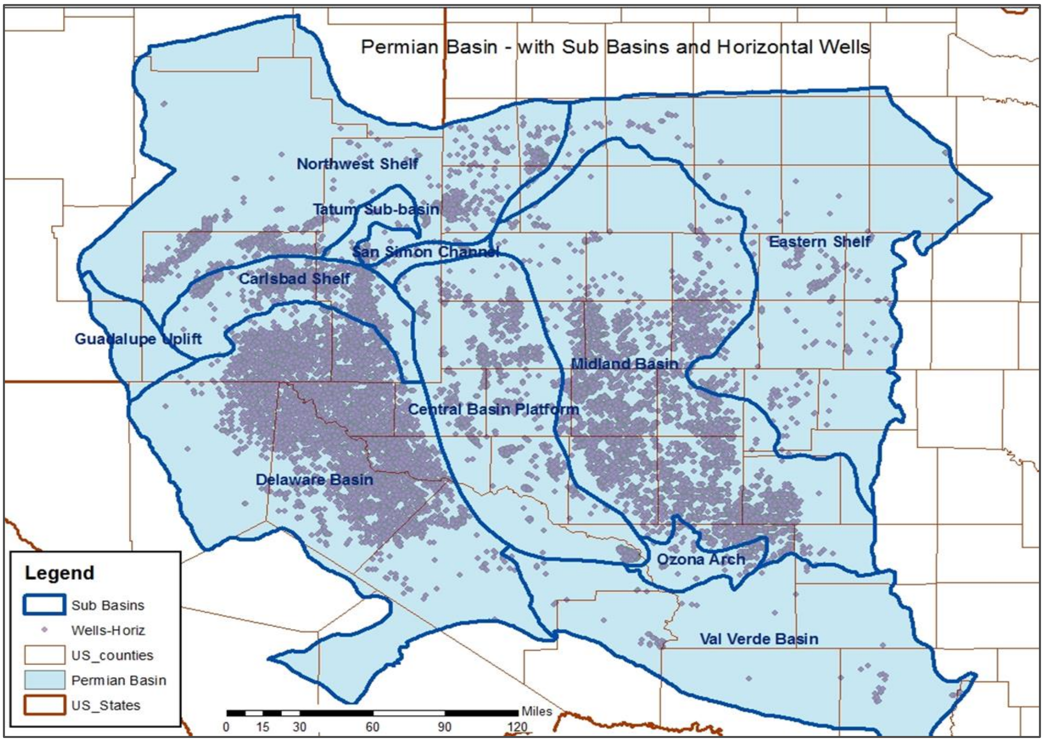

Figure 1-2. Permian Basin map, with regions

Roughly 2 million barrels per day of new Permian pipeline capacity commenced operations by the end of 2019. The ramp-up of pipeline throughput has prompted Permian operators to liquidate their large inventories of drilled-but-uncompleted wells (DUCs), boosting crude oil production in 2019 and early 2020.

Because the Permian Basin plays have the lowest breakeven prices and highest number of drilling opportunities, compared to other North American unconventional plays, IHS Markit expects that operators will consolidate their operations to focus on the Permian Basin, while moving out of or cutting operations in higher cost areas such as the Bakken (North Dakota), Eagle Ford (South Texas) and STACK (Oklahoma) tight oil plays.

1.2.2 Permian Basin structure

The Permian Basin has quickly become the largest producing basin in the United States, supplying nearly 5 million barrels per day by the end of 2019 – a fivefold increase since 2010. The vast amounts of economic unconventional resources of the Permian Basin have been the primary driver behind its growing share of the US oil supply.

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[1] Cushing, Oklahoma is a major trading hub for crude oil and a price settlement point for West Texas Intermediate on the New York Mercantile Exchange.

Among the Permian Basin unconventional plays, Bone Spring and Wolfcamp in the Delaware region, and Spraberry and Wolfcamp in the Midland region, will likely be responsible for future production growth.

The Central Basin Platform, which lies between the Delaware and Midland regions, has been the primary target of horizontal drilling into historically conventional formations.

A fair amount of conventional vertical drilling activity remains in the basin, but it has been steadily declining year over year.

Similar strata accumulated in the Midland and Delaware regions, resulting in thick sequences of potential reservoir rocks that could be developed using the new technologies of horizontal drilling and hydraulic fracturing (fracking). These thick sequences could accommodate between six and ten stacked reservoirs developed from a single drill pad.

The Delaware region represents up to 5000 feet of potential pay column in the combined Bone Spring and Wolfcamp plays. The Bone Spring Delaware play spans five to eight stacked benches or pay zones. It is comprised of a series of tight sands separated by carbonate bands with three Bone Spring sands that can be produced, as well as the Avalon Shale and two potential Carbonate/Shale zones.

The Wolfcamp Delaware play spans three to five stacked benches or pay zones. It is composed of multiple productive benches, with the Wolfcamp A and B benches being the most productive. The Wolfcamp C and D benches carry additional potential, albeit these are much gassier. The thickness of the Wolfcamp Delaware ranges from 2,000-3,500 feet.

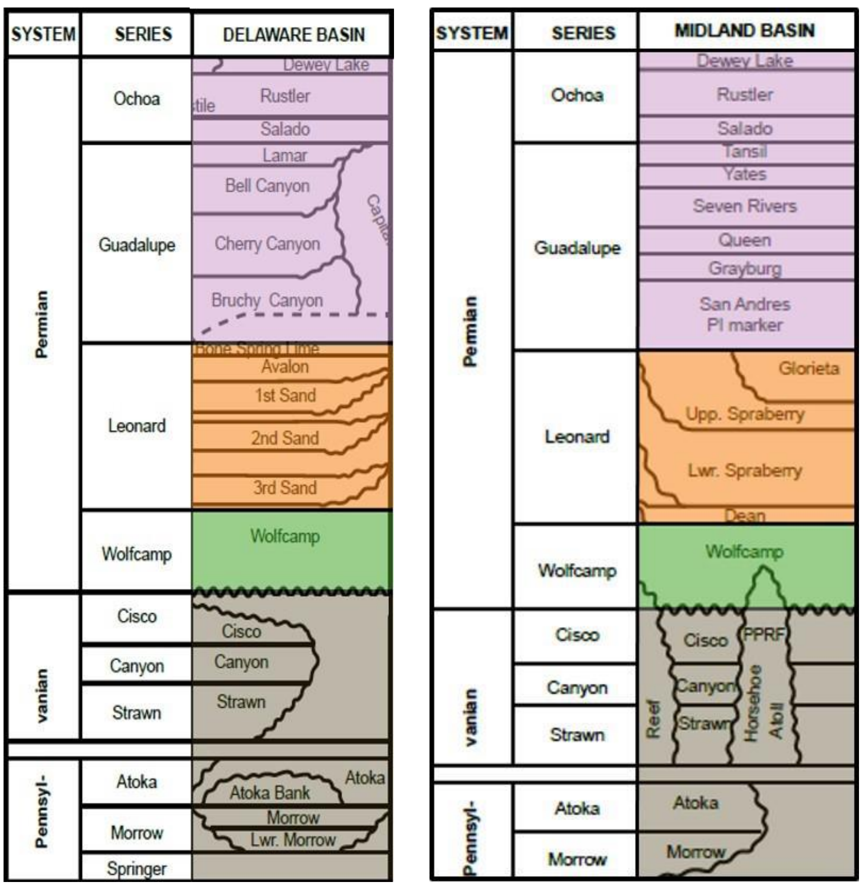


Figure 1-3. Stratigraphic columns for the Delaware and Midland regions

The Spraberry play in the Midland region has been developed vertically for decades, and now it is also being developed horizontally, although much of the focus is on the underlying Wolfcamp Midland shales.

Both Spraberry and Wolfcamp plays have multiple benches, which include the Middle and Lower Spraberry, A1, A2, B1, B2, C1, C2, and D (also known as Cline shale). On average, three to five pay zones can be economically developed.

Sweet spots have been identified in most of the benches, and the latest advances in stacked drilling from a single pad enable development of multiple zones, including those less prospective, at a substantially lower cost per well.

To date, most of the unconventional development has occurred in the Lower Spraberry shale located in the north of the basin, and Wolfcamp A and B zones.

1.2.3 Oil and gas activity forecast

The IHS Markit forecast is based on a highly granular methodology, which engages cross-sector industry expertise and technical research delivered by our numerous teams, including upstream and midstream technical consulting, commodity markets, costs, and companies and transactions. Together, the teams analyzed industry market forces, external events and limiting factors, such as capital availability and investor sentiment, that are likely to shape short-term production performance in the major US plays.

As part of this collaboration, IHS Markit gathered and analyzed the latest information about rig counts, production, and wells coming on-stream.

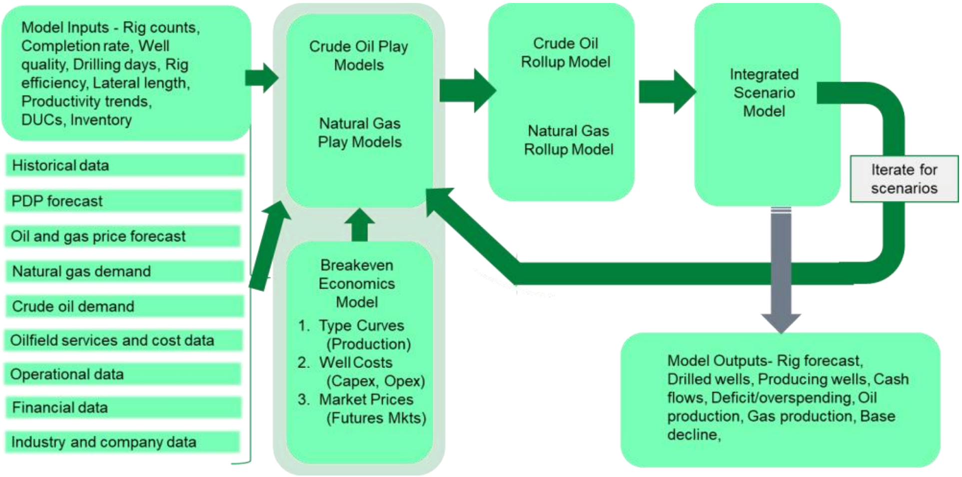


Figure 1-4. IHS Markit production forecast workflow chart

Production type curves were appropriately revised in the assessment of remaining inventories, and recent play-level trends for lateral lengths and proppant loading, as indicators of future gains.

The future activity outlook is representative of the IHS Markit teams' consensus on the expected rig activities for primary operators in plays, with the view to single-well economics by inventory quality level and commodity price outlooks. Where applicable, the activity outlook is adjusted further to account for any identified constraints to production. As a last step, power demand is linked to the resulting production forecast.

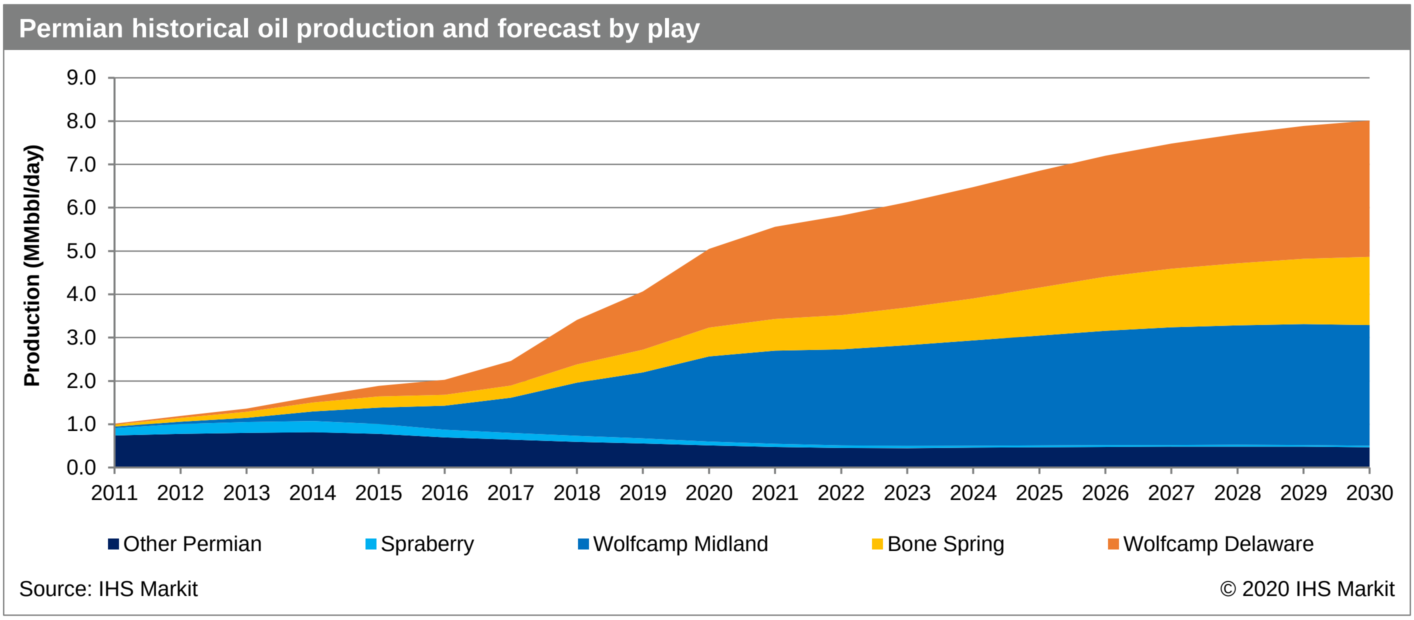


Figure 1-5. IHS Markit forecast for Permian Basin production, by play

Permian cumulative oil production is expected to reach 8 million barrels per day by the end of 2030 – nearly a 100% increase from the 2019 levels.

Associated gas, produced along with the oil, will also require power for transport, treatment and processing. At the same time, GORs will show slight increases over time in most plays, except for Spraberry. Increasing GORs imply greater power needs for gas processing.

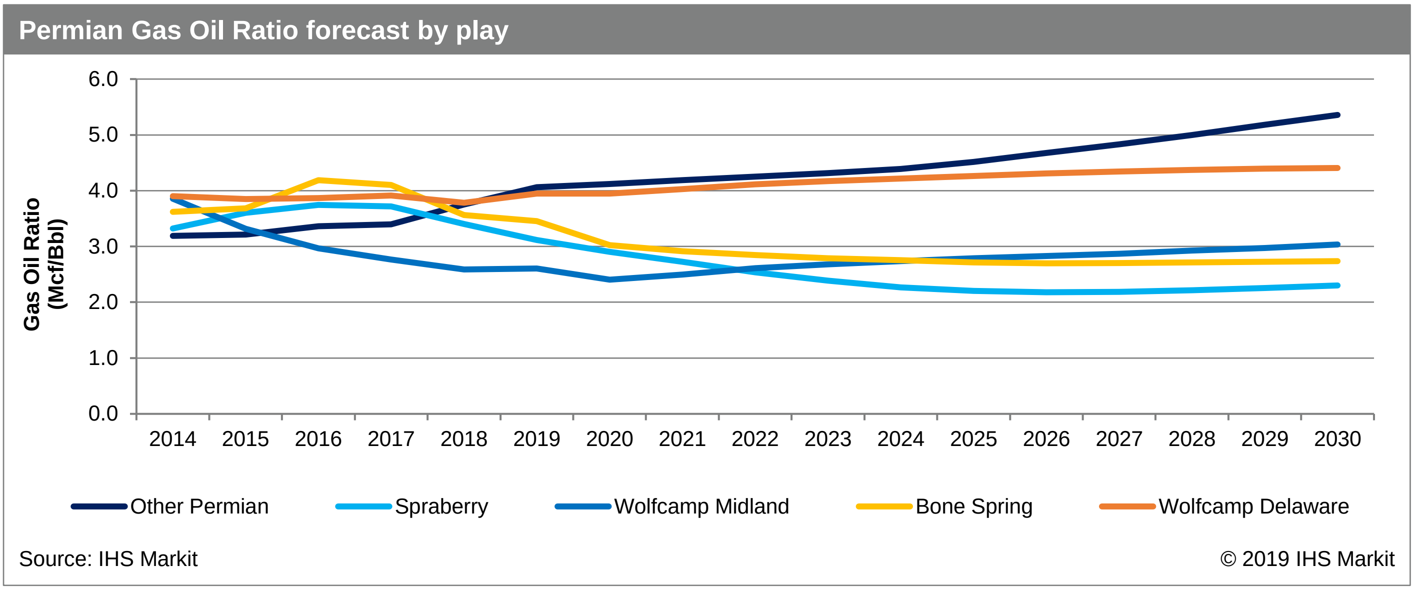


Figure 1-6. IHS Markit forecast for Permian Basin Gas Oil Ratios, by play

Power demand will also be a function of increasingly complex wells. With the cumulative vertical well count in the Permian Basin on track to reach plateau after 2020, the total well count will increase, owing to more productive and complex horizontal well drilling. Much of the new unconventional drilling activity will be focused on the Delaware and Midland regions of the Permian Basin where unconventional resources occur.

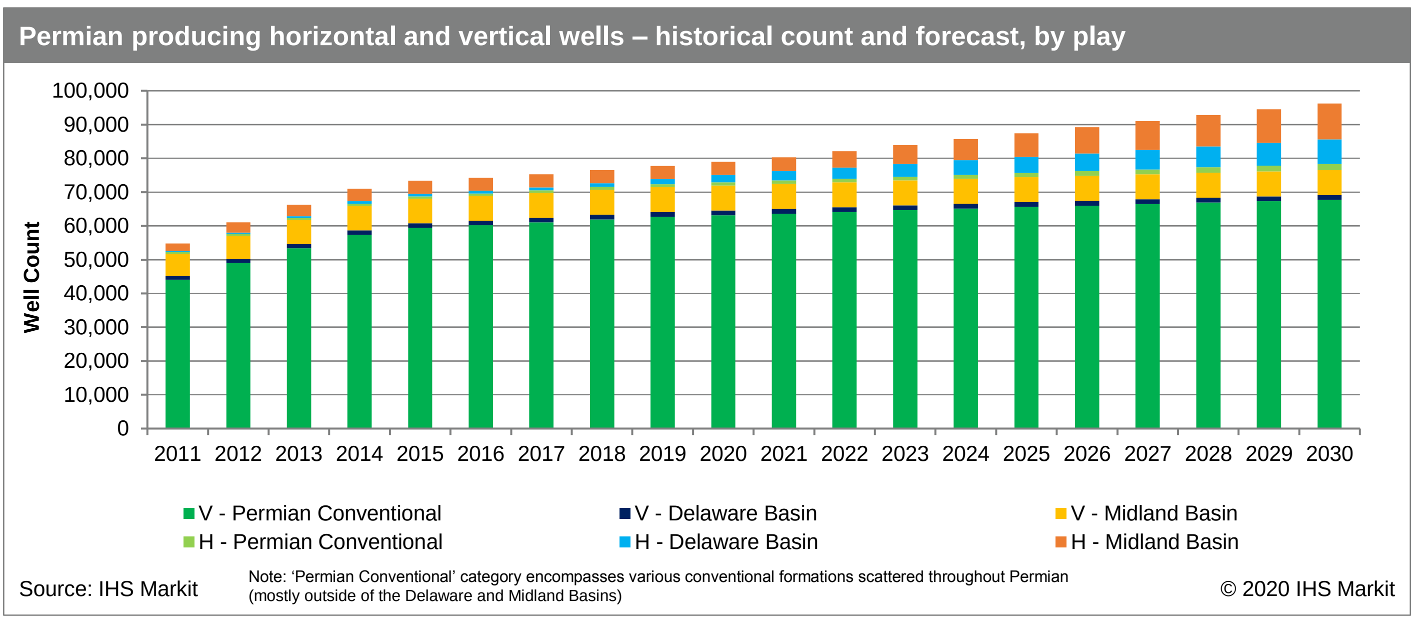


Figure 1-7. IHS Markit forecast for Permian Basin wells, by play and type

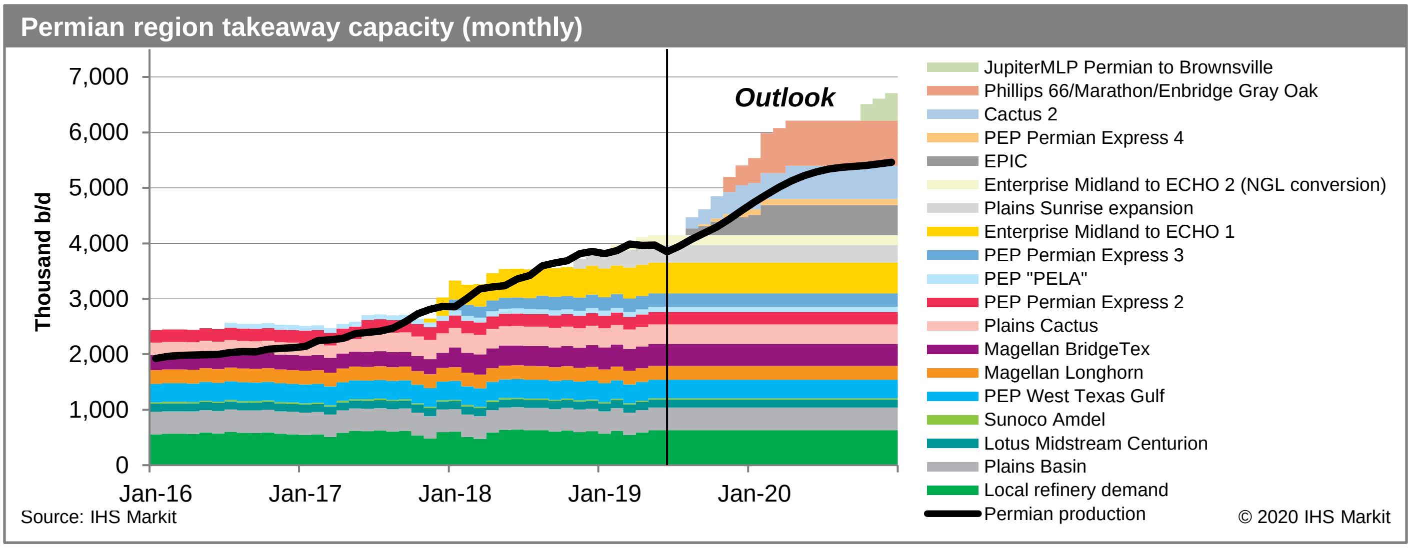


Figure 1-8. IHS Markit forecast for Permian region takeaway capacity

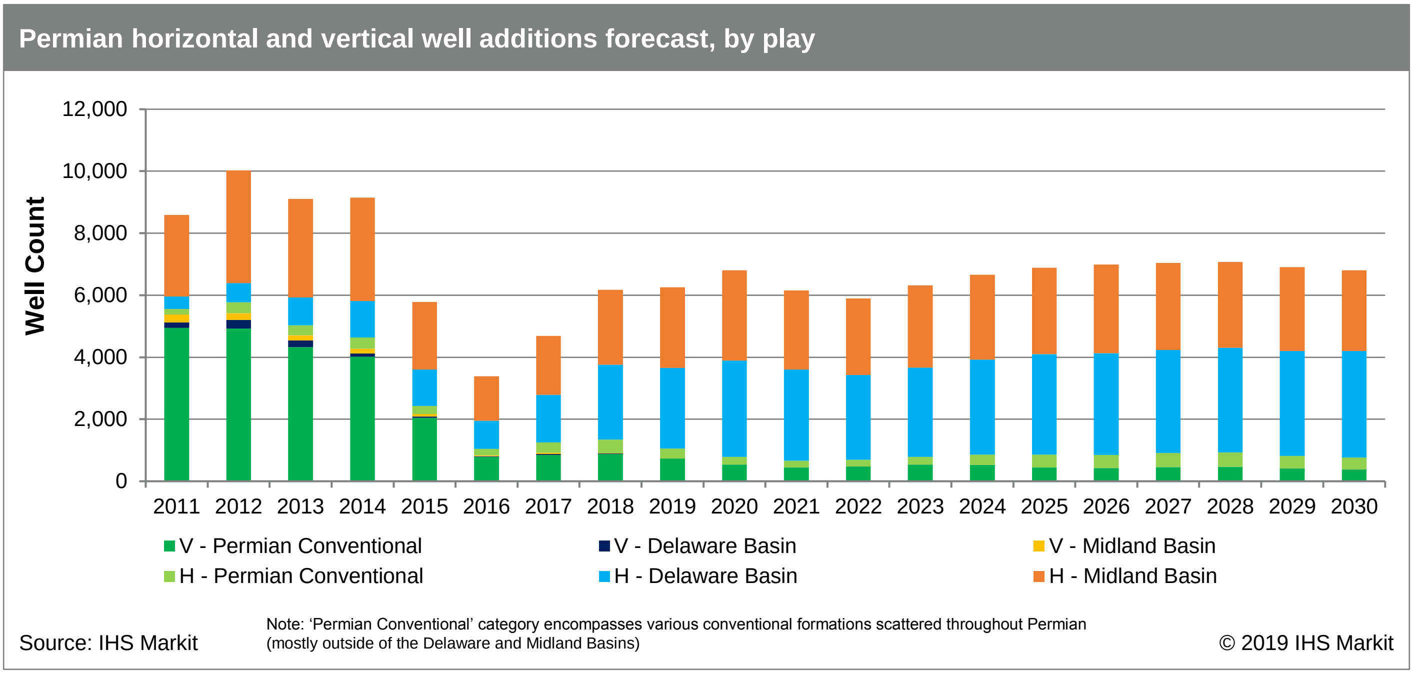


Figure 1-9. IHS Markit forecast for Permian Basin wells, by play

The pipeline length emerging out of the Permian appears enduring, removing significant risk of further in-basin bottlenecks or basis blowouts for the foreseeable future. In total, at least 3.7 million barrels per day (bbl/d) of new capacity is already operating or planned by 2021.

Slowing production is likely to see spot rates reduced to compete for barrels to fill the new lines, and expensive options, such as rail and truck, should largely cease, all conferring advantage to Permian oil getting to market.

Cactus 2 (670,000 bbl/d, operated by Plains All American), EPIC (ultimately 600,000 bbl/d, operated by Ares Management Corporation), and Gray Oak (900,000 bbl/d, a JV between Phillips 66, Marathon Petroleum, and

Enbridge) are now operational. Much more will come online. As of late September, Energy Transfer Partners has expanded its Permian Express pipeline system by 120,000 bbl/d, Enterprise is expanding its Midland-ECHO system by 450,000 bbl/d in second half 2020, and the Wink-to-Webster project (a JV between ExxonMobil, Lotus Midstream, Plains All American, Marathon Petroleum, Delek, and Rattler Midstream) is expected by 2021 at a capacity between 1 and 1.5 million bbl/d.

The large DUC inventory, which accumulated modestly in the first half of 2019 due to takeaway capacity constraints, will be a key contributor to Permian Basin growth over 2020. With new pipes to fill and company spending under pressure, we expect producers to start converting some of their DUCs in the second half of 2020, thus, improving the capital efficiency, lifting overall well additions, and boosting output. Considering the lower oil price outlook, IHS Markit expects a lower DUC conversion rate, effectively extending the period to drawdown DUC wells to levels closer to the normal working inventory.

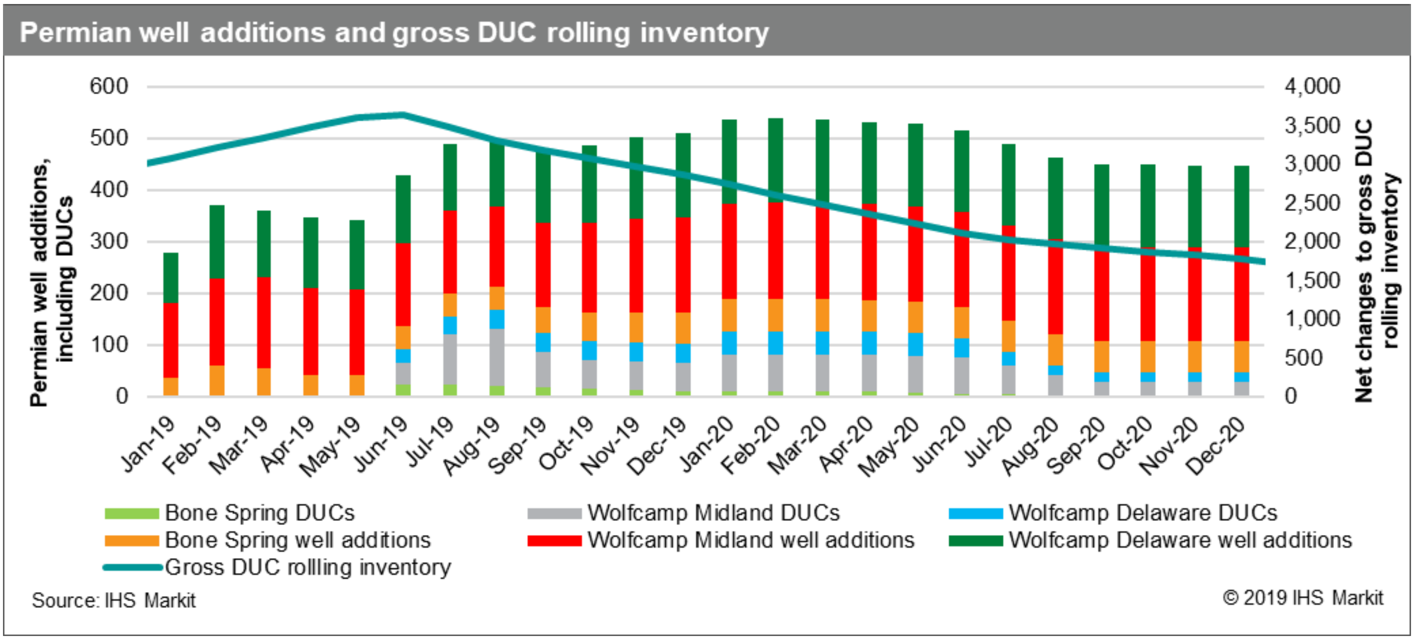
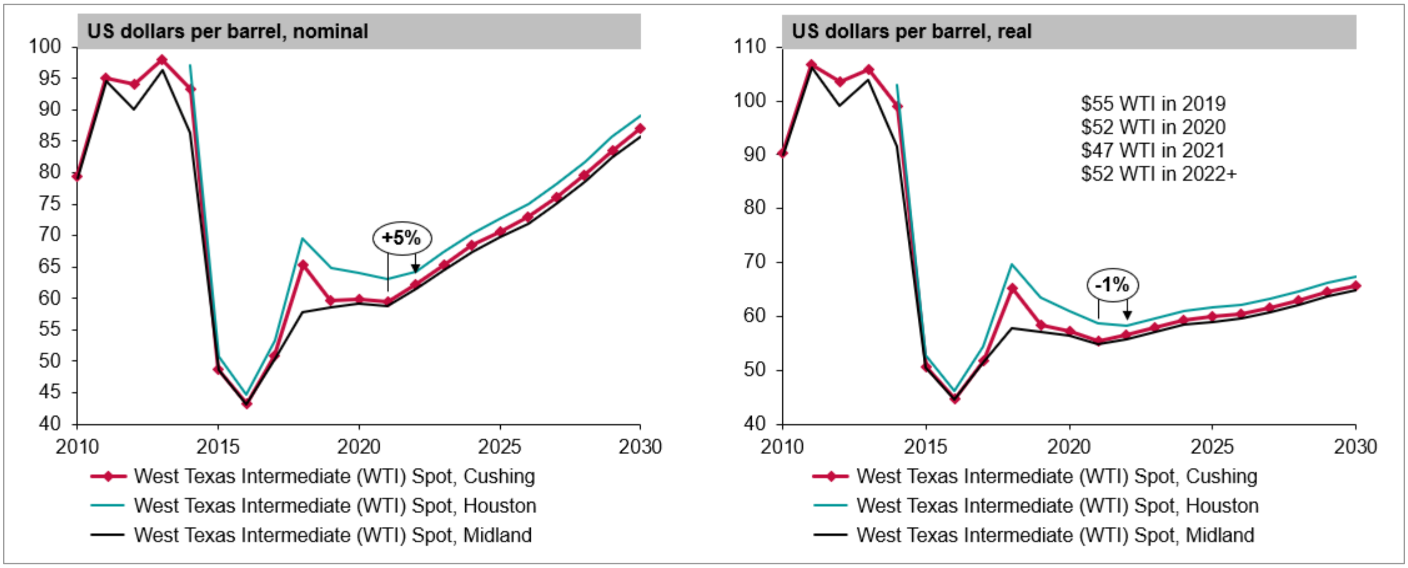


Figure 1-10. IHS Markit forecast for Permian well additions and gross DUC inventory

1.2.4 Short-term industry trends

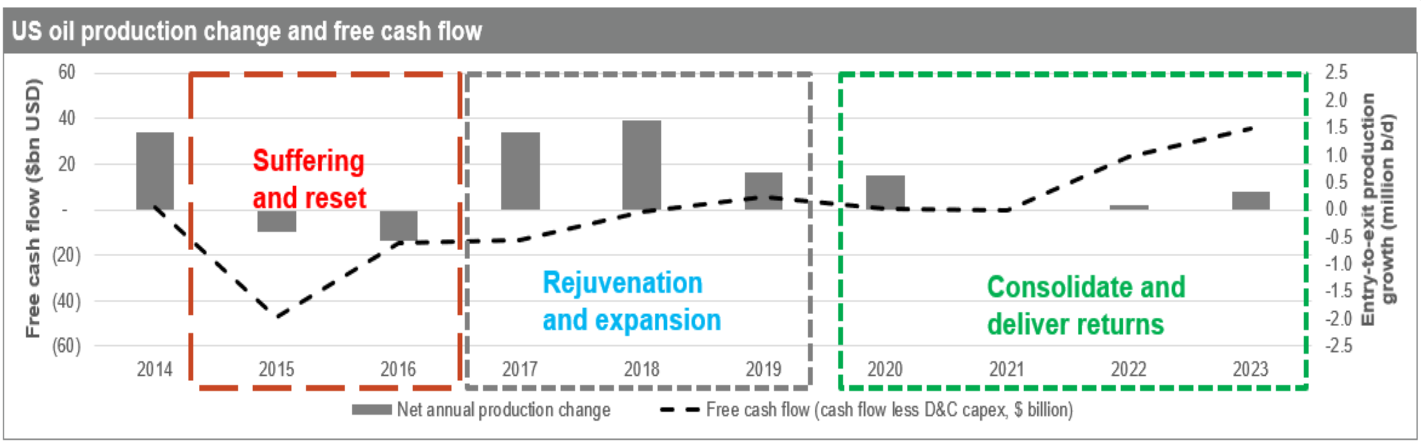
In the IHS Markit North American long-term crude oil price outlook, WTI Houston is expected to trade at a much smaller premium to WTI Midland.

With stable oil pricing in the $55 to $65 per barrel range, keeping capex growth below output growth over several years slows supply expansion, moderates decline, and promises to allow US producers to enjoy a rising and substantial yield of fee cash.



Figures 1-11 and 1-12. IHS Markit North American price outlook (WTI)

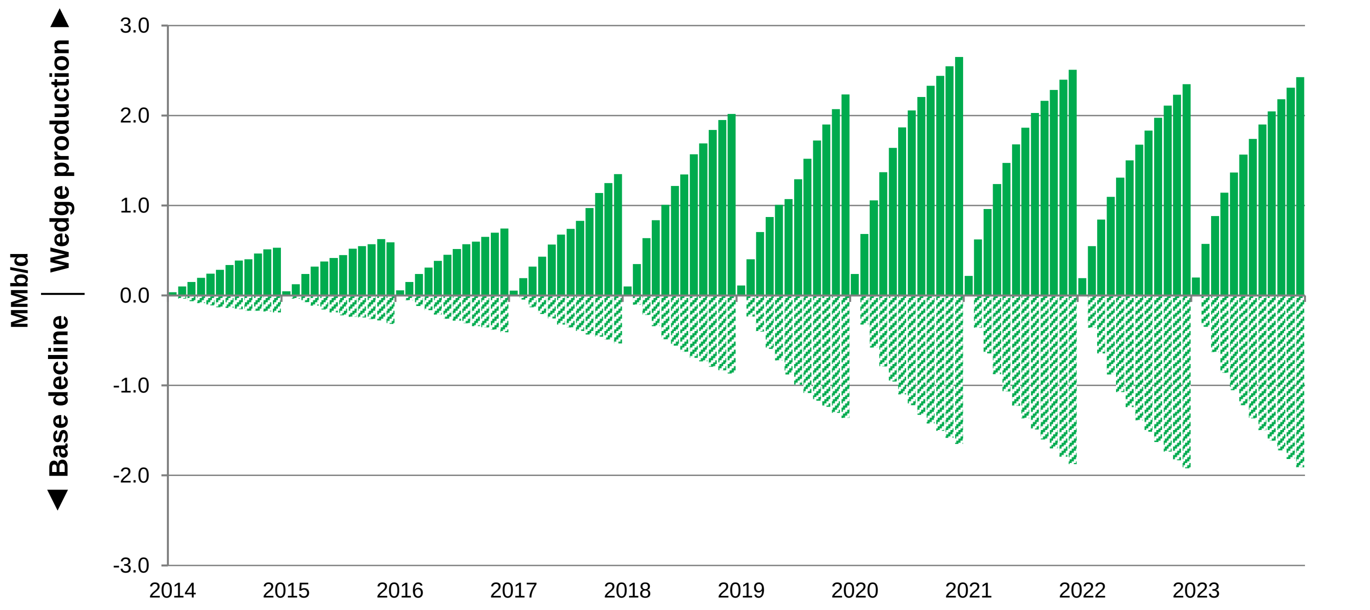
Figure 1-13 and Table 1-1. IHS Markit outlook for production growth capital, by year



Maintenance (flat production) and growth capital split, and US onshore free cash flow, by year	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Maintenance capex ($ billion)	90.3	96.1	49.1	44.0	71.9	86.3	77.6	83.5	87.8	96.0
Growth capex ($ billion)	65.6	-	-	32.2	40.1	15.3	12.3	-	2.1	8.3
Free cash flow (cash flow less D&C capex, $ billion)	1	(48)	(14)	(13)	(1)	6	0	(1)	23	36
Free cash flow margin (%)	1%	-66%	-27%	-16%	-1%	5%	0%	0%	17%	22%

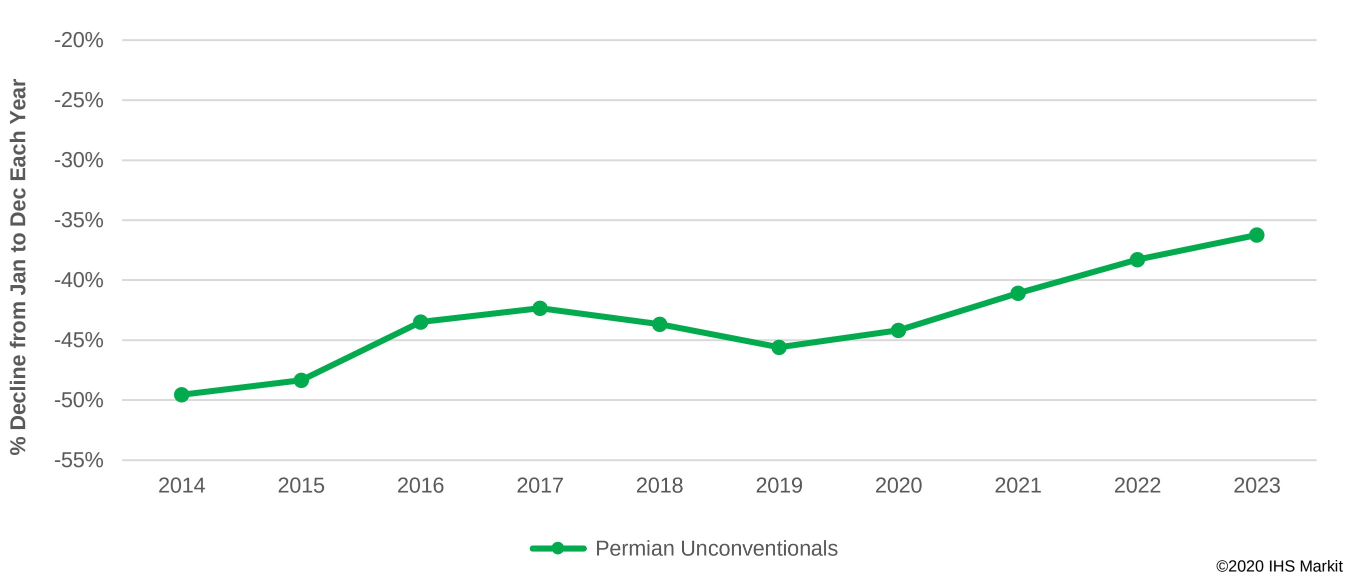
New drilling in the Permian Basin will outpace the natural declines in production which have been increasing in recent years. The growth spurt from 2017 through 2019 has pushed base decline rates for the onshore system to record levels in both absolute (about 3.5 MMbbl/d) and percentage (about 35%) terms. At the play level, we expect the base decline rates of the Permian Basin to moderate from 2020-2023, dropping below 40%. This will allow for moderate growth in net production at WTI prices in the mid-$50's by the early 2020s.

Base decline and wedge production for the Permian Basin



Source: IHS Markit © 2020 IHS Markit

Permian Basin - base decline evolution: historical and forecast



Figures 1-14 and 1-15. IHS Markit outlook for production growth vs. base decline

Exploration and production (E&P) companies' inability to outspend cash flow, coupled with high decline rates following years of rapid growth, leave them exposed to a sharp deceleration with WTI prices around $50, tipping into contraction if prices fall into the $40s. In the near-term low-price forecast, the Permian Basin will be the only growth engine within the US, with decreases in other plays.

Total US oil production scenarios based on various prices and cash return strategies

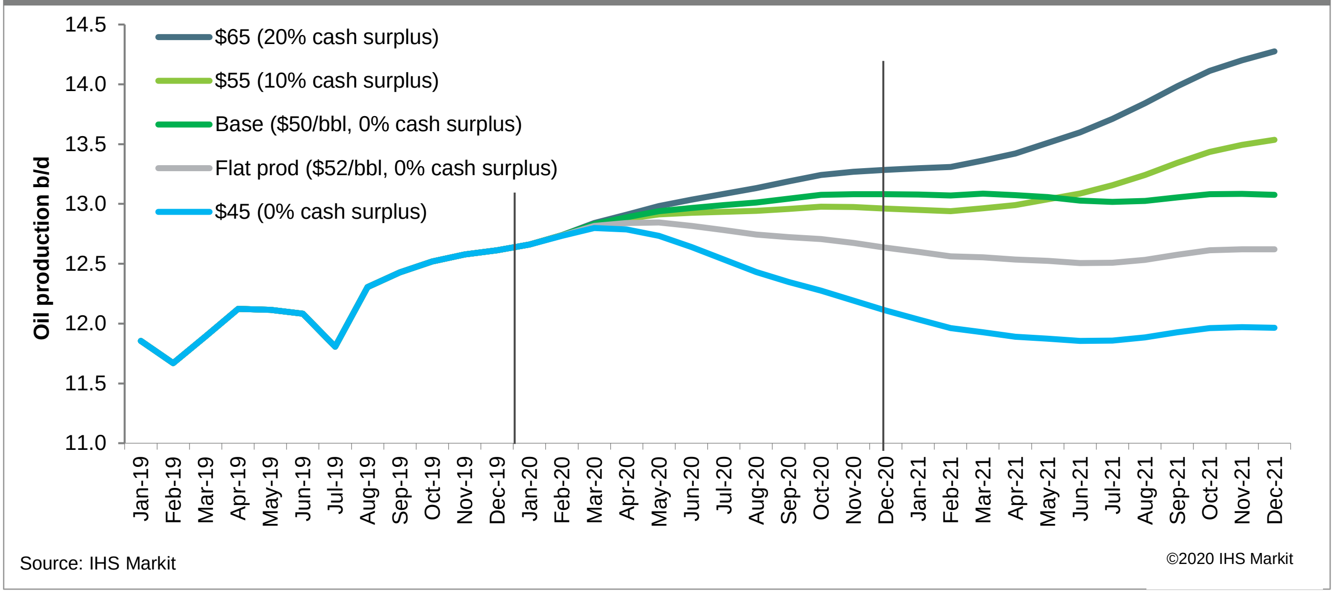


Figure 1-16. IHS Markit outlook for production growth at various price

Short-term US production growth for key basins

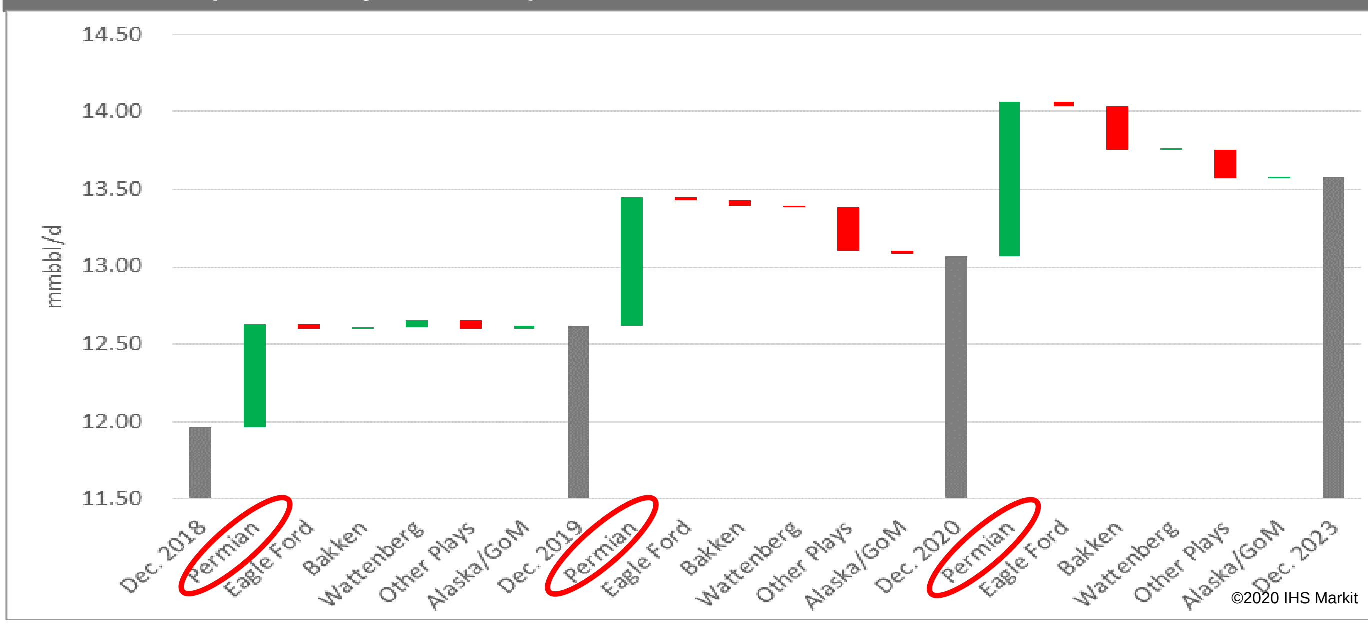


Figure 1-17. IHS Markit outlook for production growth at various price

1.2.5 Long-term resource estimates

Wolfcamp Midland continues to yield consistent well results as over 90% of the wells brought online during the past year break-even economically below current WTI prices, with most of the uneconomical wells located in the Southern Midland sub-play. The most productive and economic wells were in the Northern Midland sub-play, with many of the operators having wells break even at less than $35/bbl. The Eastern Midland sub-play also had attractive well economics, with wells having a breakeven under $40/bbl. Wells in the Southern Midland sub-play remain unproductive and uneconomical as very few operators break even below $50/bbl.

All but the fifth quintile wells in Wolfcamp Midland break even at current WTI prices. Over the past year, the first three quintiles accounted for over 70% of well activity and about 80% of production in the Wolfcamp Midland.

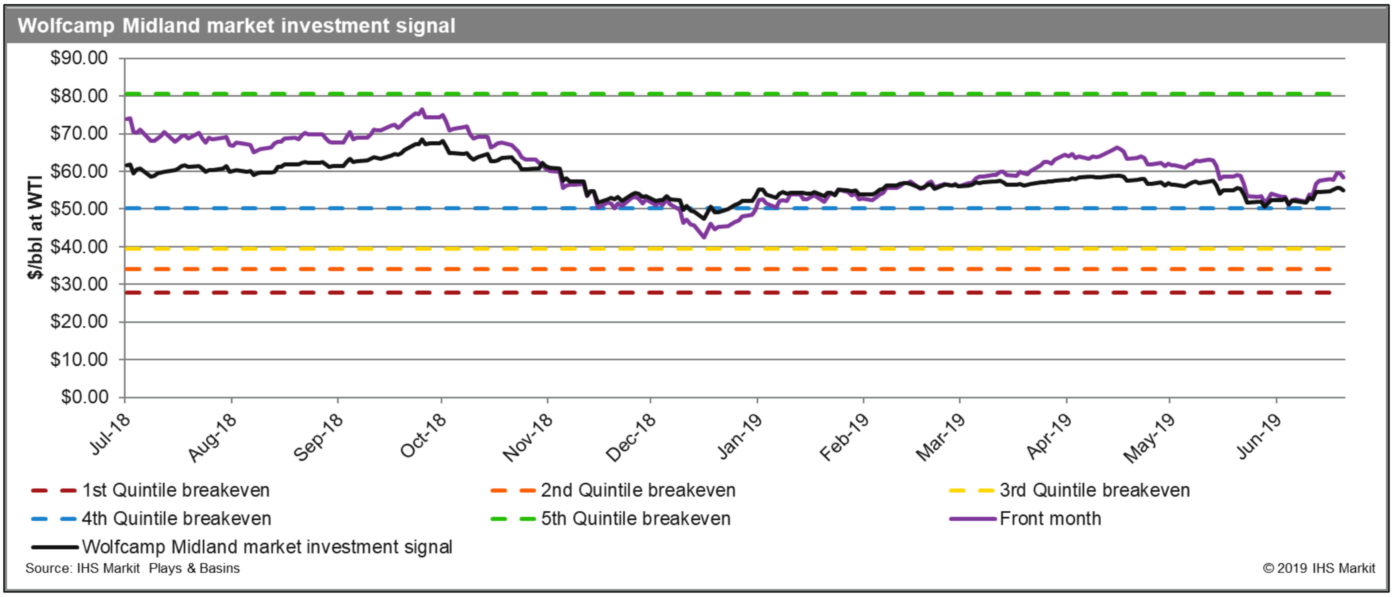


Figure 1-18. Wolfcamp Midland well economics by quintile

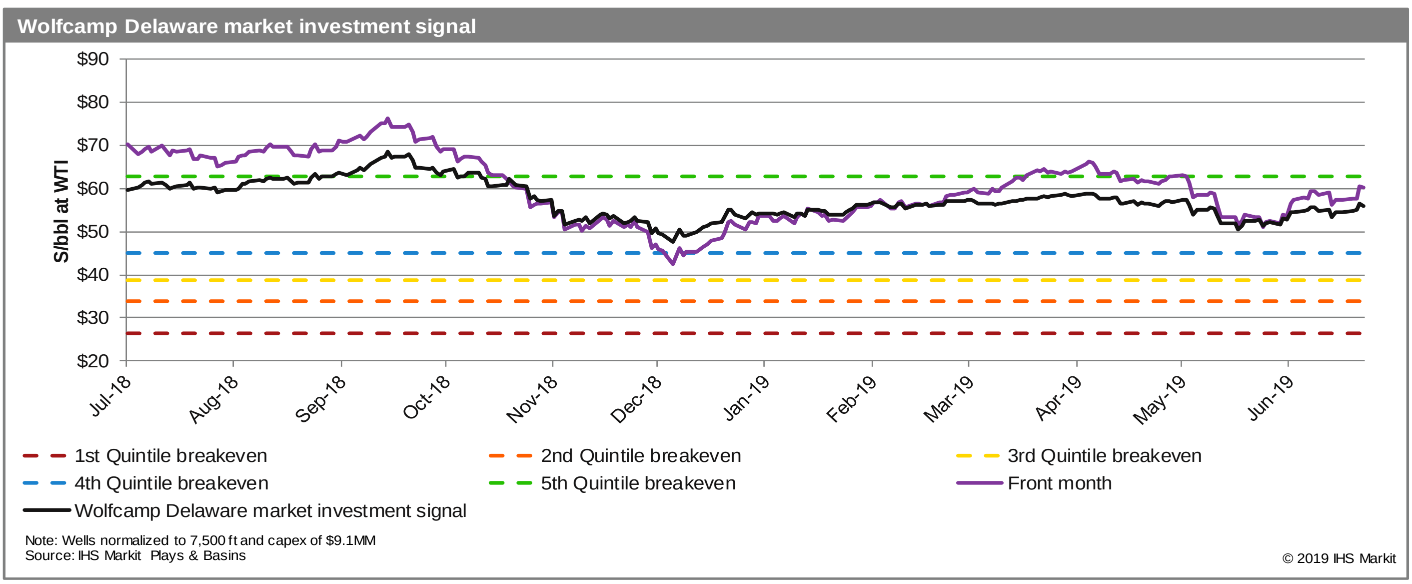


Figure 1-19. Wolfcamp Delaware well economics by quintile

On the other hand, Wolfcamp Delaware productivity gains are mostly finished. Proppant intensity grew from a play-wide average of 1,500 pounds per foot (lb/ft) in 2016 to 2,200 lb/ft in 2017. The drastic increases stopped in 2017, and nearly all operators are adopting completions between 2,000 lb/ft and 2,500 lb/ft - a range that appears near optimal for best productivity in the play. Some indications of success at 3,000 lb/ft were present in 2018, with productivity uplift at that level.

In the past year, only about 7% of the wells brought online had relatively high break-even price above $50/bbl, accounting for less than 5% of new volumes. The average break-even price for core areas within Permian Basin is below $45/bbl WTI, showing relative security of returns regardless of the price.

Despite productivity of major Permian Basin horizontal plays leveling off in recent years, the Bone Spring remains the most productive play, not only in the Permian, but across all the US Onshore plays, outperforming even the prolific Wolfcamp Delaware by roughly 10–20% quarter over quarter. Bone Spring productivity is around 170–180 barrels of oil equivalent per day (boe/d) per 1,000 lateral feet (20:1), while Wolfcamp Delaware productivity hovers between 150–160 boe/d per 1,000 lateral feet (20:1).

Except for two brief drops in WTI price that occurred from November 2018 to February 2019 and in late May to early June 2019, only about 6% of wells brought onstream since July 2018 did not break even below $55/bbl. Further, these wells only contributed 2% to new volumes in the same timeframe, highlighting the appeal of the Bone Spring play, which has been virtually isolated from recent oil price fluctuations.

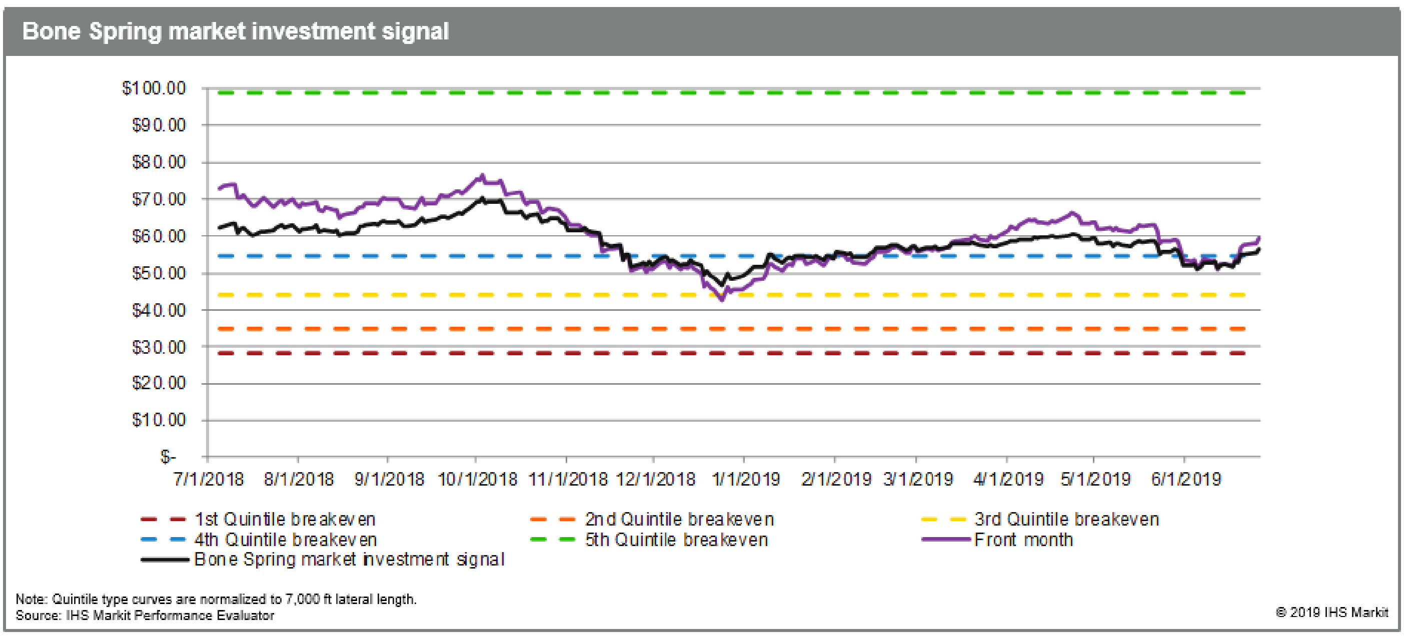
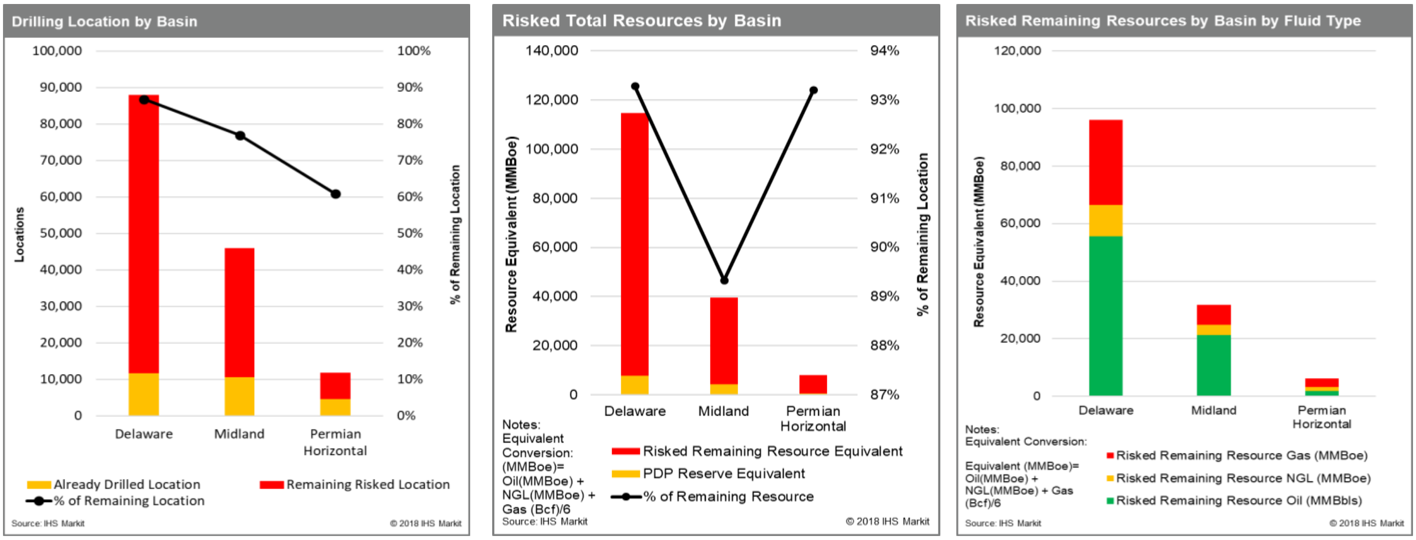


Figure 1-20. Bone Spring well economics by quintile

As previously mentioned, IHS Markit expects the unconventional oil plays located in the Delaware and Midland regions to supply most of the future drilling locations, with the Permian horizontal conventional plays supplying less than 10% of the future potential.

In the base case, total undrilled resources reach 78.7 billion barrels of oil (Bbbl), 15.8 billion barrels of NGL, and 239 trillion cubic feet (Tcf) of gas. About 60 to 90% of the future locations have yet to be drilled with less than 10% of the future production being PDP.

The Delaware region will provide over double the amount of future resources as the Midland region, with a large share of that future supply difference being gas and NGLs. For example, the Midland region will supply 21.2 Bbbl of Proved Undeveloped (PUD) oil, whereas the Delaware region will supply about 55.6 Bbbl, or more than double. Likewise, the Midland region will supply 42 Tcf of PUD Gas, and the Delaware - 177 Tcf – over four times as much.



Figures 1-21, 1-22, 1-23. Permian Basin remaining risked resource by region

Eight plays contribute 84% of the remaining resources, five of these are in the Delaware region. The top play, namely the Wolfcamp A, will contribute 39%

The Alpine High *, contributing 3% of the total resources, which is mostly gas. However, while contributing relatively high BTUs, the play will contribute less economically as the price ratio of a barrel of oil to Mcf of gas is 20-1.

Similarly, the Wolfcamp A and B, located in both Midland and Delaware regions, will contribute 68% of the total future resource. The Wolfcamp Delaware benches, however, will be more gas weighted.

(* – Alpine high is an emerging gas play located in Culberson County, west of the main Delaware Basin Wolfcamp and Bone Spring plays.

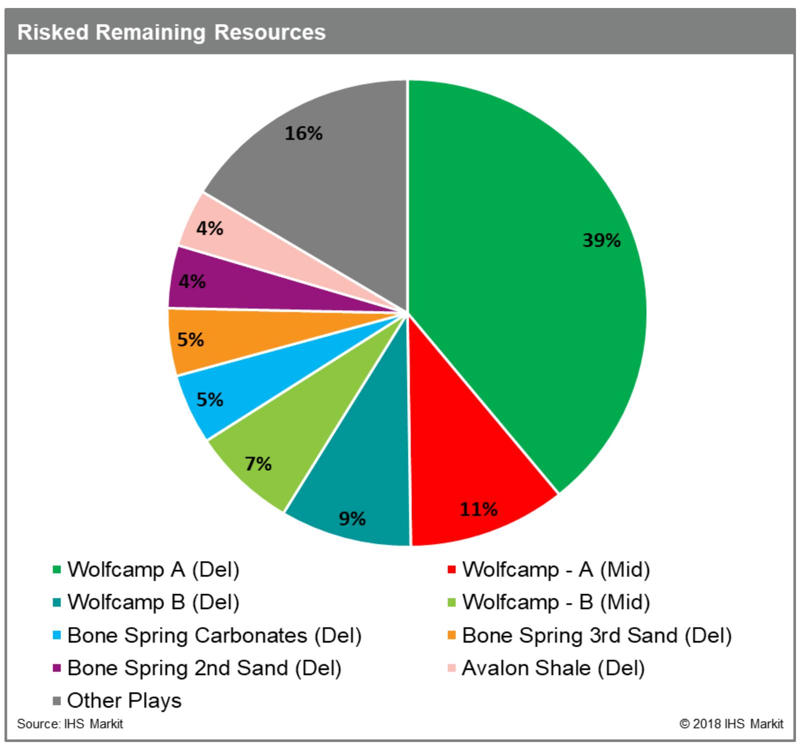


Figure 1-24. Permian Basin remaining risked resource by play

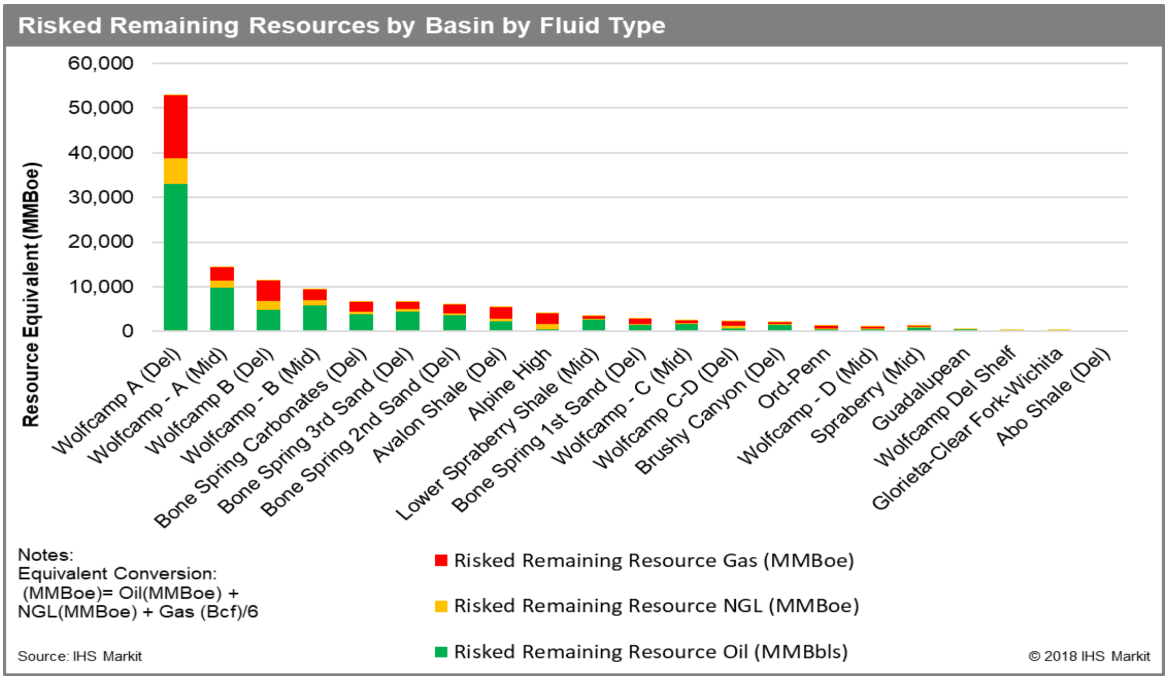


Figure 1-25. Permian Basin remaining risked resource by play and fluid type

Drilling activity in unconventional plays remains overwhelmingly concentrated within the most productive acreage that encompasses relatively small core areas. In mature and smaller plays, including the Eagle Ford, Bakken, and Wattenberg, exhaustion of undeveloped drilling inventory in core areas is likely to emerge as soon as the mid-2020s. By the late 2020s, exhaustion is likely to be observable within most liquids plays, including the Permian Basin, but to a lesser degree in the Permian than in other plays. The remaining undeveloped locations far outweigh the exhausted locations in the two key Permian regions.

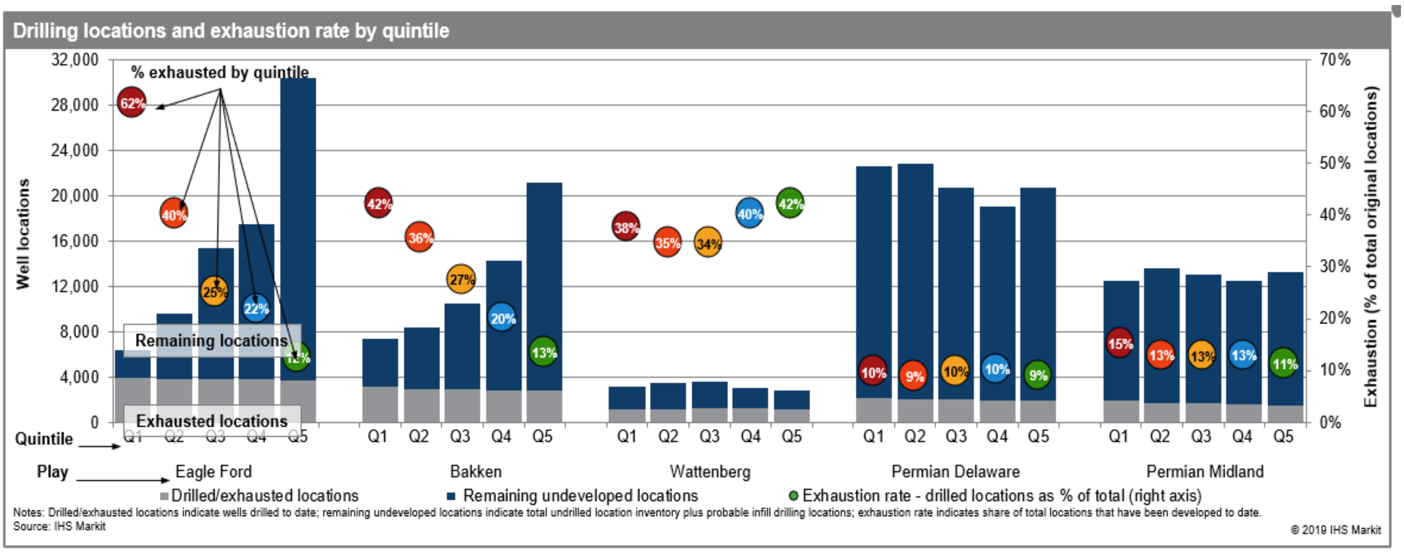


Figure 1-26. Drilling inventory exhaustion rate by play and quintile

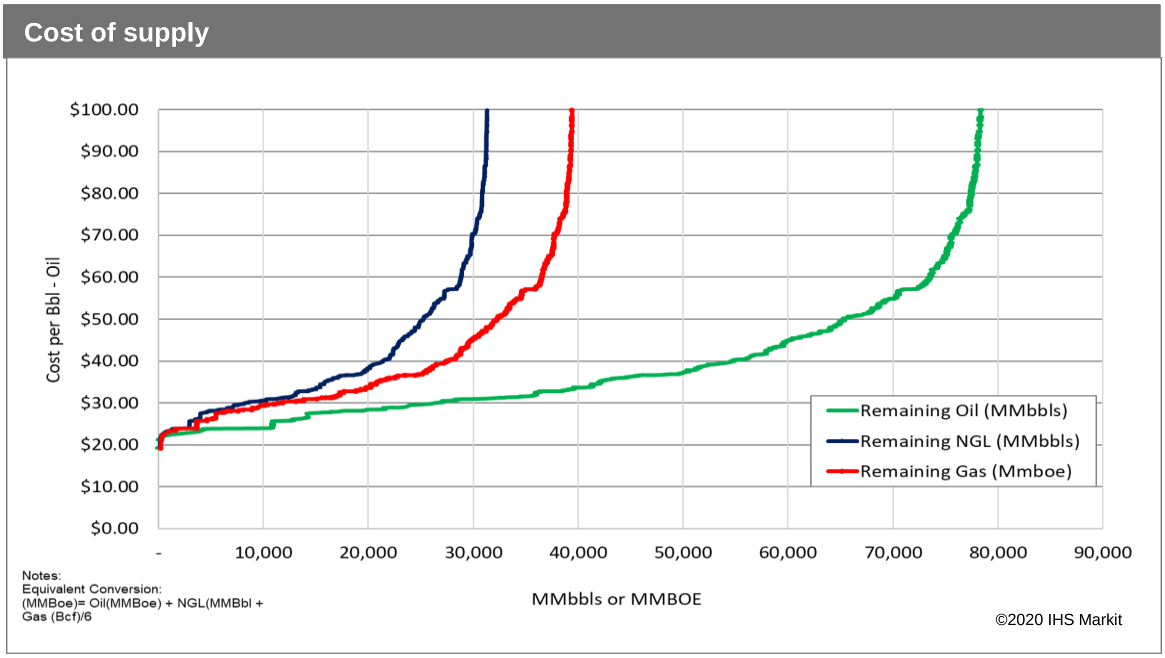
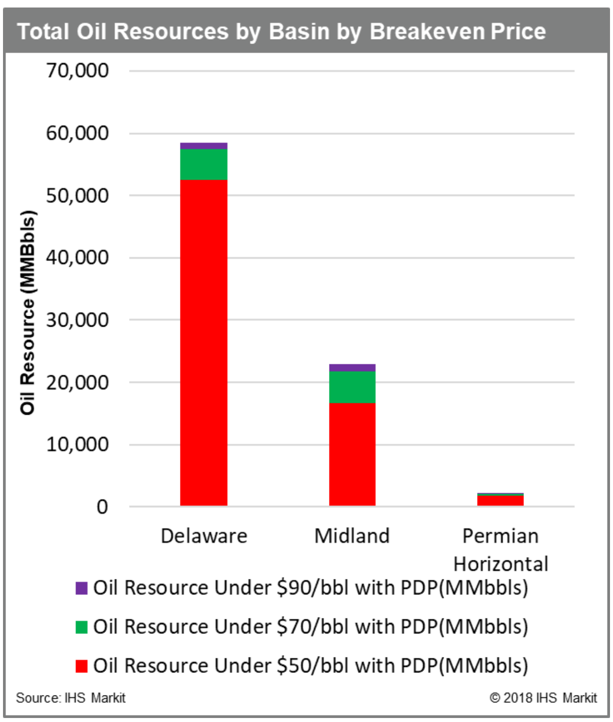


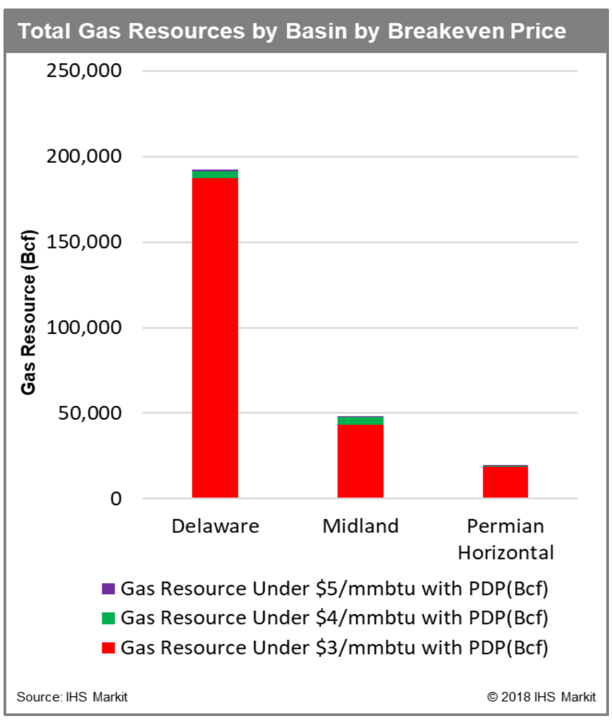
Figure 1-27. Cost of supply by product type

Due to recent performance increases and efficiency gains, 65 Bbbl out of the 78 Bbbl (or 85%) of total oil resource breaks even under $50/bbl. The associated dry gas that can be produced alongside this low-cost oil is 248 Tcf, representing 97% of the available dry gas resource.

While there is uncertainty in any oil or gas price forecast, most experts, including IHS Markit, agree that the price will remain above $50/bbl (in real terms) throughout the forecast period. As far as gas resource is concerned, this means that oil will drive the gas production forecast, and given the high GORs, particularly in the Delaware Basin, we can expect that low-cost to no-cost gas will continue to flow from the Permian Basin.

Unless oil prices completely collapse, the flow of gas from the Permian Basin will not be price dependent on either the oil or the gas price. Possible gas flow curtailment may occur only if infrastructure for oil or gas take-away is lacking.





Figures 1-28 and 1-29. Oil and gas resource by break-even price

2 Power Demand for Oil and Gas Activities

2.1 Overview

Industrial power demand in the Permian Basin is driven by oil and gas production and related activities including water handling. In the previous part, we developed an oil and gas production forecast for the Permian Basin which we have allocated to the individual county level in order to forecast the necessary power demand for each county. Part 2 describes these county level forecasts and the associated oil and gas operations; these are evaluated by the type of operations – upstream, which includes exploration and production activities, and downstream, which includes processing and transportation of oil and gas prior to market. The purpose of this part is to describe the various oil and gas activities that require electrical power, relate these activities to production and drilling historical data at the county level and to describe the methodologies and assumptions used to quantify power usage for each activity.

Findings

- Oil, gas and water production require power to produce, transport and handle. County-level forecasts of oil and water production were required to determine power demand for each county.

- The 24 Permian Basin counties were grouped into four regions: Central Basin Platform, Midland Basin, Delaware Basin, and Fringe Areas,

- The oil production from the four regions is expected to reach nearly 6 MMbbl/d by the end of 2030 with the Delaware and Midland Basin groups being the two major drivers of future oil production supply. Oil and associated water production is expected to keep growing steadily through 2030 to over 30 MMbbl/d.

- These total liquids forecasts suggest that power demand growth will occur in counties where total liquids production from horizontal wells is projected to increase; however, despite forecasted declines in oil production from some counties with vertical well production, we can expect power demand to continue, and in some cases may even increase slightly due to excessive water production issues.

- Most of future liquids production will come from wells located exclusively in the Delaware and Midland regions. In the short term, both oil water production will contribute greatly to overall liquids production; but in the long run, with the high and gradually increasing Water Oil Ratios (WOR), water production will become a more significant long-term driver of overall liquids production.

- The Central Basin Platform area is considered to be mature, and the Fringe area in Texas has limited upside potential for oil and gas activity. Therefore, nearly all the remaining locations in the Permian Basin are expected to be horizontal wells for long term growth. Related power demand as well as pumping profile changes should be expected throughout the productive life of a well, which will ultimately contribute to future power demand.

- The number of new wells brought online each year will remain consistently stable while cumulative well counts will increase. With more and more wells entering the later stage of well life, WOR will increase and water production would be the prevailing liquid in the long run.

- The continual addition of new wells with high initial production rates keeps WOR rates relatively constant at about four barrels of water for each barrel of oil produced. Once the development of horizontal wells ceases or slows down significantly, the WOR rates are expected to rise dramatically and at some point, approximate those observed in vertical wells which have reached up to 10 barrels of water per barrel of oil produced.

- To calculate the total upstream electricity required on a per county basis, the main drivers of power use in the upstream sector were calculated and converted into electricity demand in megawatts (MW). The rates of total oil and water production, the production rates which utilize electric submersible pumps (ESP) and rod pumps, and saltwater disposal (SWD) systems and facilities located near the well were calculated for each month and then converted into electricity demand in megawatts.

- IHS Markit has estimated average power required for the transportation of oil, gas and NGLs, as well as power required for the operation of refineries and gas processing plants. There may be additional components of the midstream operations that draw power, but these components are too small to impact the overall forecast or else run on gas-generated power. Within the Permian Basin, the preponderance of midstream electric grid power is used by gathering systems and gas processing plants.

2.2 County-Level Oil and Water Production Forecast

2.2.1 Methodology for Creating County-Level Forecasts

As noted in Part 1, the Permian Basin oil and gas forecasting process is performed at the play level utilizing several inputs that are evaluated by IHS Markit experts, including:

- Using rig counts, production data, and current wells on-stream;
- Incorporating type curves[2] (i.e. single well production profiles), which represents production performance;
- Utilizing operational trends, such as lateral length, well spacing and proppant loading;
- Incorporating assumptions of future lateral lengths and remaining well inventories;
- Evaluating economics and price outlooks;
- Calculating break-even prices which could then be applied to anticipated drilling activity;
- Assessing individual rig activity trends by primary operators; and
- Adjusting the forecast to any identified constraints to production.

Plays that are forecasted individually include the Bone Spring and Wolfcamp located in the Delaware Basin, the Wolfcamp and Spraberry plays located in the Midland Basin, and the Permian conventional production, which includes some production from horizontal wells but consists primarily of production from legacy vertical wells that have been producing for decades.

For this study, county level forecasts were required in order to determine power demand for each county. This required us to perform production forecasts for all Permian Basin counties, including those located in New Mexico; however,

[2] Type Curves summarize average well performance decline profile to permit effective forecasting and reserve estimation for evaluations.

once this task was completed, we then dropped the New Mexico counties from the forecast and from the remainder of the study.

Using our latest Permian Basin short-term and long-term production forecasts we allocated a portion of the production to each respective county by using similar forecasting models that we routinely use to generate our production forecasts. This includes generating applicable input to the models by performing the following steps:

1. Utilizing the production history, historical new well counts and producing well counts for each county as a starting point to generate the forecasts. This is actual historical data that was tied into any future projections.

2. Allocating production outlooks from individual plays into the respective counties. Figure 2-1 shows the general location of the respective plays and the corresponding counties. Note that the Bone Spring and Wolfcamp generally overlay each other and the Midland and Spraberry do as well. This geographic coordination of plays to counties made it possible so that we only had to allocate each play to a handful of counties.

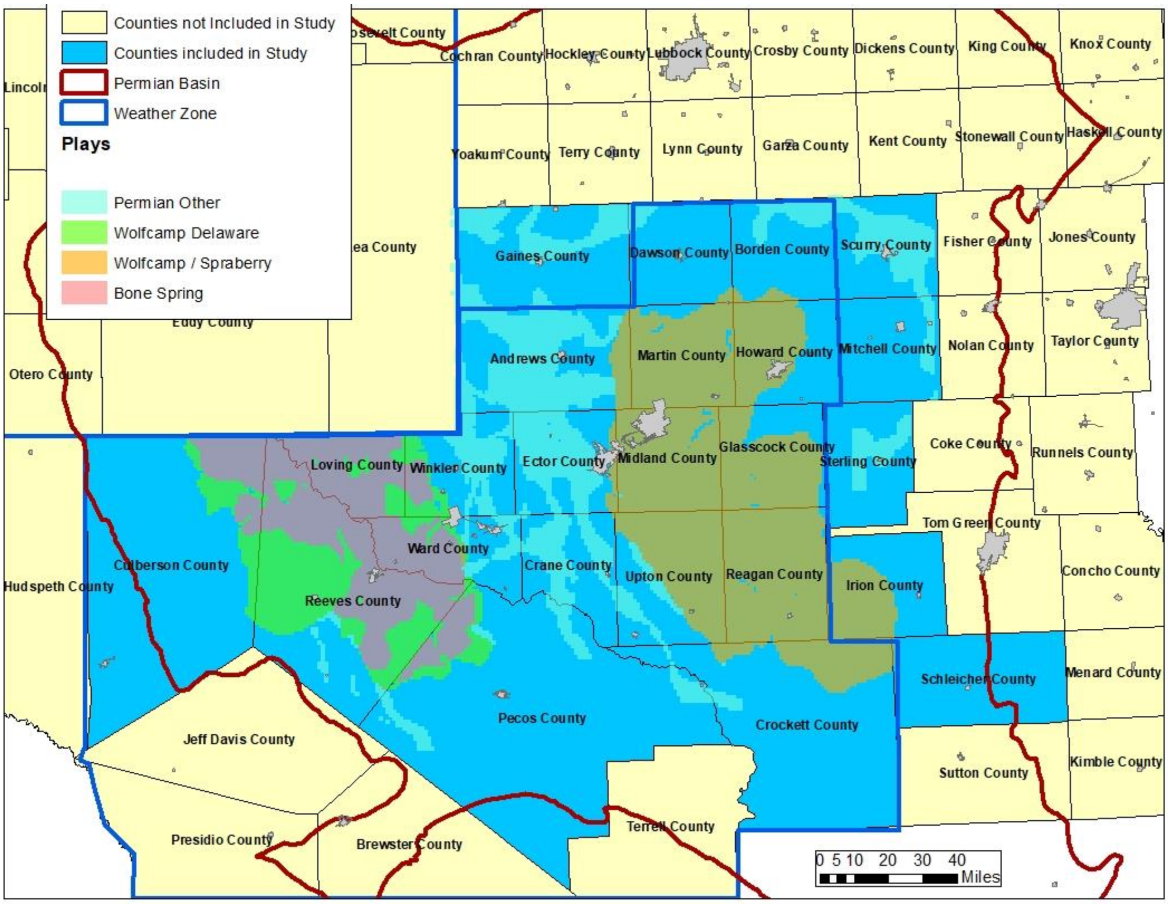


Figure 2-1: Plays Associated with Counties

3. Determining remaining locations within each county for each play. In previous studies we have calculated and mapped remaining resources and number of locations for each play. Using geographic information system (GIS) tools, we identified the number and quality of remaining locations in each county, which was a key input into our forecasting models

4. Assessing the relative performance within each county by creating county level type curves that were input into the models to generate production streams for oil and associated gas.

5. Creating development plans for each county based on the relative number of locations and quality of production in each county compared to that of other counties within the respective play. In other words, counties with better producing wells are going to get developed faster than those with lesser quality resource.

6. Rationalizing county level forecasts with play-level forecasts. This final step was an iterative process to ensure that the individual county-level forecasts within each play added up to the total forecast for the respective plays. Once this rationalization was complete for each play, we then added the forecasted results together within each county, where multiple plays existed in those counties. For example, Loving County includes both the Wolfcamp and Bone Spring plays; hence, the forecasts for both of these plays were summed together to obtain a single forecast for Loving County.

7. Calculating water production. Since associated water production is an important component of power usage, a forecast of water production was also performed at the county level. This water production stream was calculated based on the historical WOR within each play at the county level. From these calculations, water production profiles were generated and applied to generate the associated water forecasts.

2.2.2 Determining Regional and County Level Forecasts

The 24 Permian Basin counties were assigned into four different regional county groupings that are loosely associated with the respective plays and sub-basins within the Texas portion of the Permian Basin. By grouping counties in

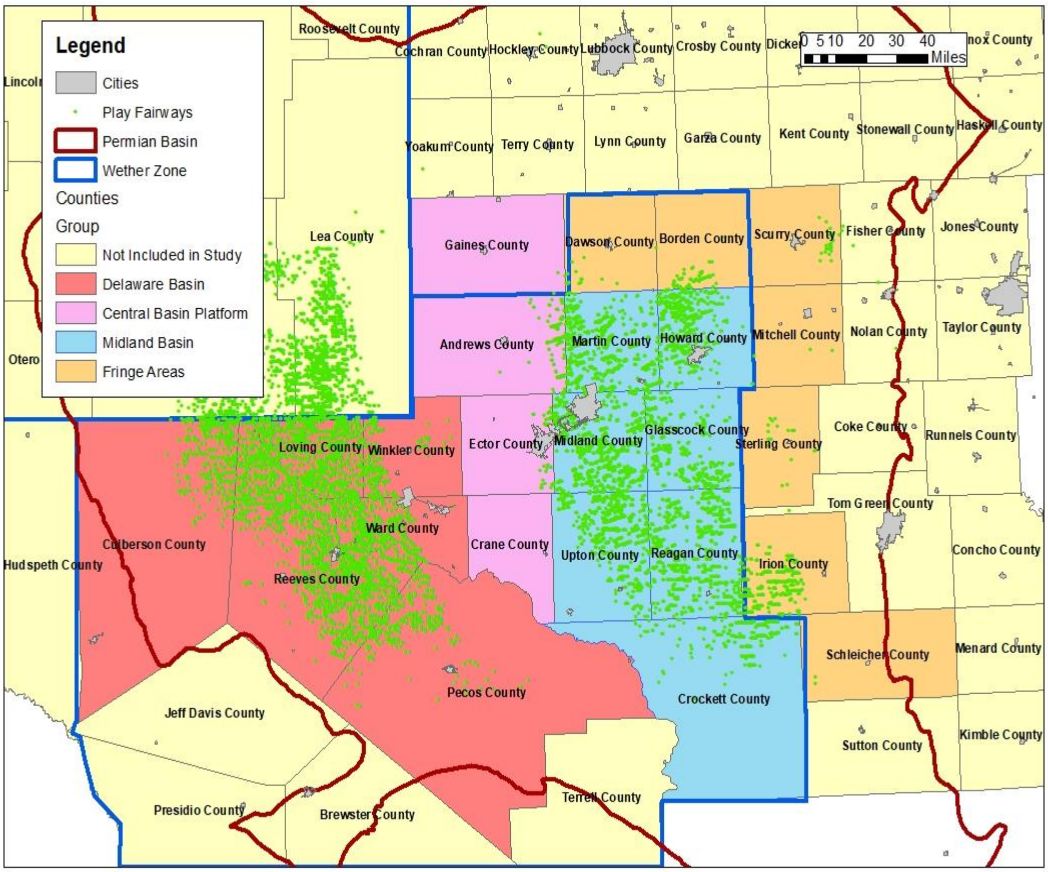


Figure 2-2: Permian Basin Region Divided into Regions

mature and emerging petroleum provinces, we can begin to match historical power usage to oil and gas activities in a way that makes sense. Furthermore, we can determine areas where future power demand is most likely to occur.

The detailed groups are as follows, as shown in Figure 2-2:

- **Central Basin Platform** - Mature petroleum province with legacy conventional production primarily from vertical wells and some horizontal wells where we expect gradual decline in the years ahead

- **Midland Basin -** Maturing petroleum province where unconventional production from horizontal wells is expected to continue to grow

- **Delaware Basin -** Emerging petroleum province where we have seen significant recent growth in unconventional production from horizontal wells and that production is expected to continue to rapidly grow.

- **Fringe Areas** -Mature petroleum province where minimal contributions to new power demand are likely to occur.

Regional oil production forecasts: Figure 2-3 and Figure 2-4 display historical and forecasted production from the Texas portion of the Permian Basin by play and by regional grouping. The play-level forecast is slightly higher as it includes oil production from 43 counties compared to the regional grouping forecast from four regions that include the 24 counties in the study. Note that the production difference is negligible at just under 0.1 MMbbl/d; hence the exclusion of 20 Permian Basin counties where we see virtually no increases in future industrial power demand. The oil production from the four groupings is expected to reach nearly 6 MMbbl/d by the end of 2030, with the Delaware and Midland Basin groups being the two major drivers of future oil production supply.

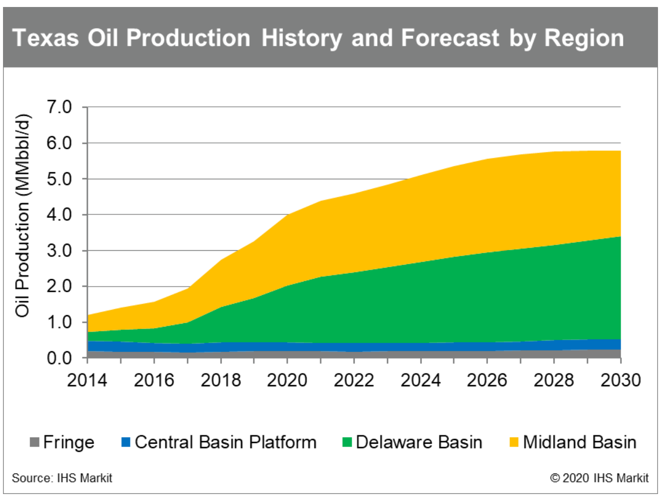


Figure 2-3: Texas Oil Production History and Forecast by Region

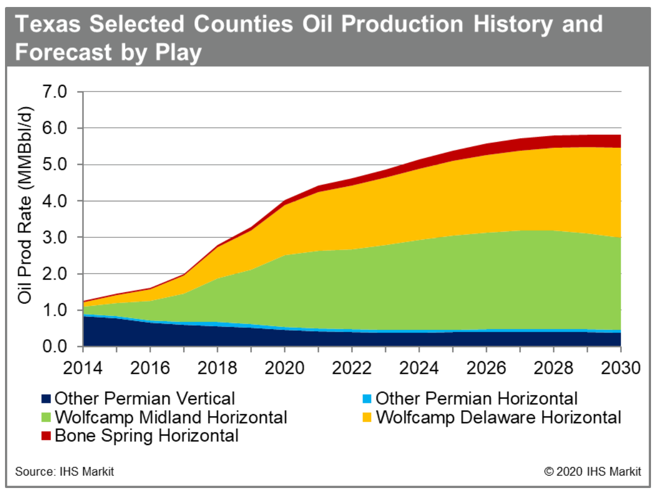


Figure 2-4: Texas Selected Counties, Permian Basin Oil Production History and Forecast by Play

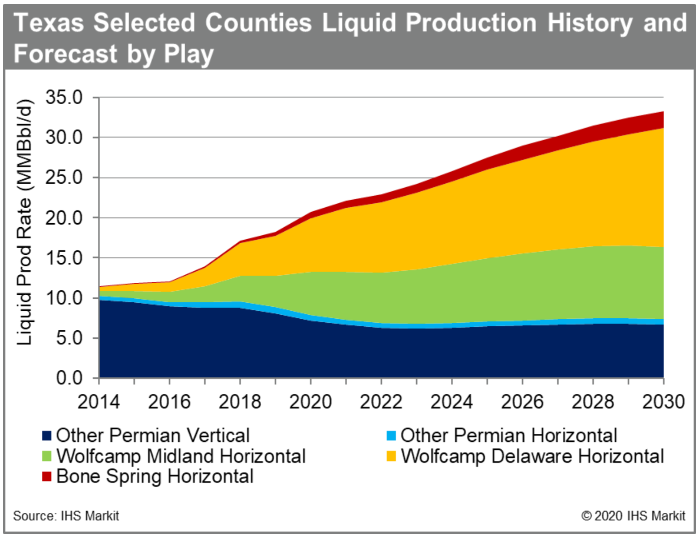


Figure 2-5: Texas Selected Counties Liquid Production History and Forecast by Play

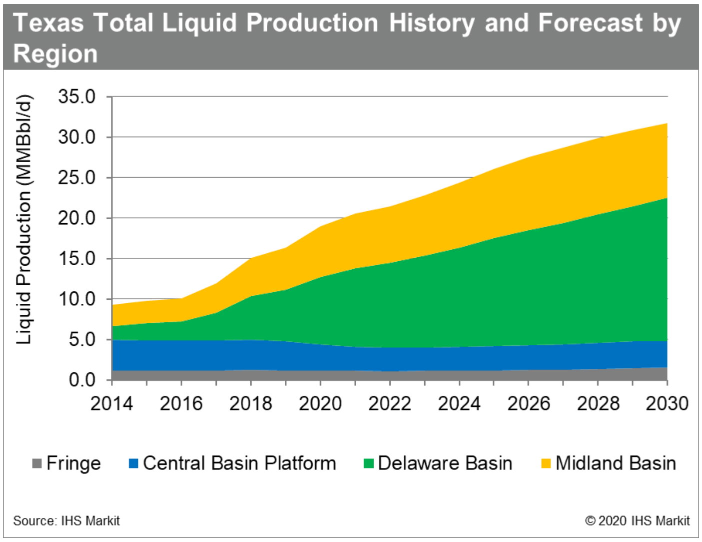


Figure 2-6: Texas Total Liquid Production History and Forecast by Play

Regional oil and water production forecasts: Similar trends are observed when oil and water production are bundled together with the Midland and Delaware Basins contributing the lion's share. Overall production is expected to keep growing steadily through 2030 to over 30 MMbbl/d as shown in Figure 2-5 and 2-6. We do see higher volumes of water produced from the other two regions as well. Given that total liquids production requires power use, the water forecasts become increasingly important as there are generally about 4 barrels of water produced for every barrel of oil as evidenced by the historical and forecasted WOR (see Figure 2-7). Note that in the future the water production will grow even more relative to oil production.

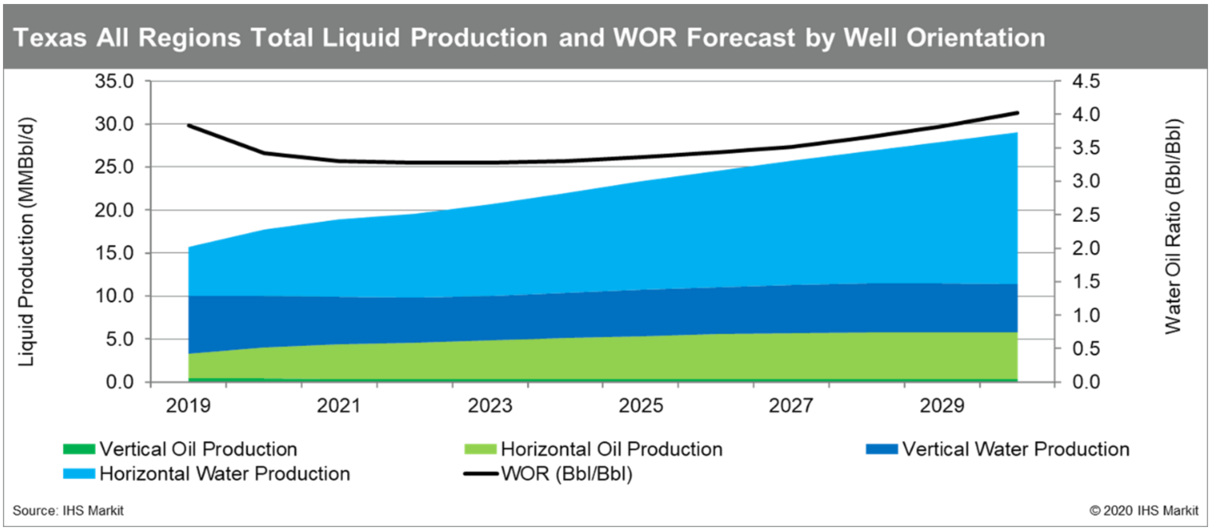


Figure 2-7: Texas Total Liquid Production History and Forecast Well Type

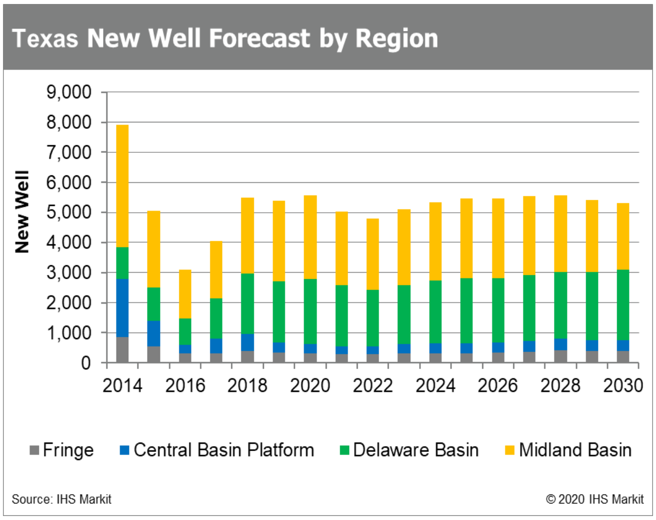


Figure 2-8: Texas New Well Forecast by Region

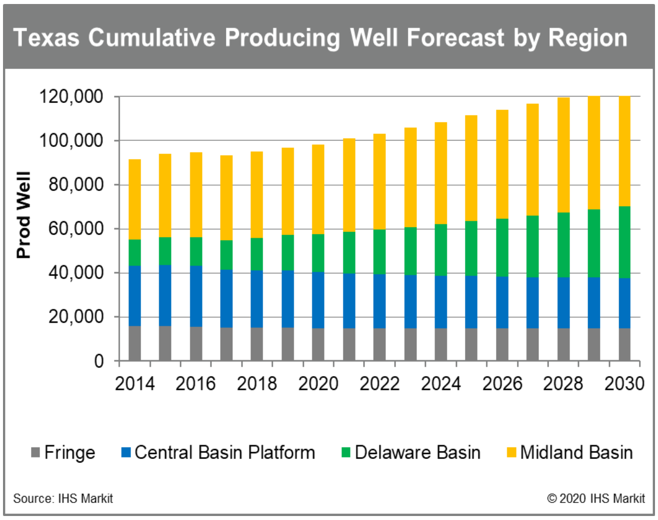


Figure 2-9: Texas Cumulative Well Forecast by Region

Vertical wells have been and will continue to be drilled in the Fringe and Central Basin Platform, while horizontal wells are projected for the Delaware and Midland Basins (see figure 8). Although future drilling will be primarily horizontal (see Figure 2-8), there is still a substantial amount of water production from legacy vertical wells, which have even higher WORs than horizontal wells. As shown in Figure 2-9, roughly half of the producing wells include 40,000 legacy vertical wells (located mostly in the Fringe and Central Basin Platform) will continue to produce oil and water, which means that this number will remain relatively constant during the forecast period.

These total liquids forecasts suggest that power demand growth will occur in counties where total liquids production from horizontal wells is projected to increase; however, despite forecasted declines in oil production from some counties with vertical well production, we can expect power demand to continue, and in some cases may even increase slightly due to excessive water production issues from both long-lived horizontal and vertical wells.

Continuous development of unconventional plays keeps WORs relatively flat. Within a single well, water production relative to oil and gas production increases over time. When we apply this principle to situations where few new wells are coming on-stream compared to producing wells, we see overall increases in the WOR as water production outpaces oil production. This is certainly the case in conventional plays dominated by vertical wells. On the other hand, this observation of increasing WOR for single wells over time is partly hidden by the aggressive development that is occurring and is forecasted to occur over the next 10 years. The continual addition of new wells with high initial production rates keeps WOR rates relatively constant. Once the development of horizontal wells ceases or slows down significantly, the WOR rates are expected to rise dramatically and at some point, approximate those observed in vertical wells.

2.2.3 Regional Group Level Forecasts

2.2.3.1 Delaware Basin

The Delaware Basin includes six counties with all, or a portion of each county located in play fairways. Here overall oil production will top 2 MMbbl/d by 2030 with water production increasing to nearly 16 MMbbl/d shown in Figure 2-10 and Figure 2-11. The GOR will gradually increase after 2021 as more associated gas production begins at a higher rate relative to the increase in oil production.

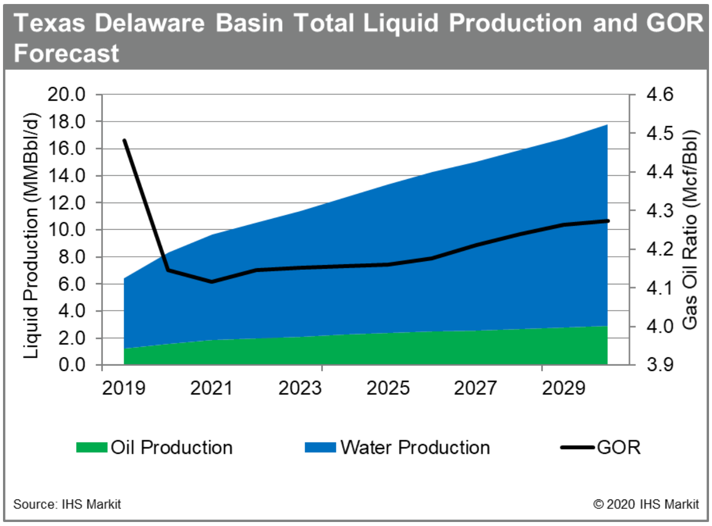


Figure 2-10: Texas Delaware Basin Total Liquid Production and GOR Forecast

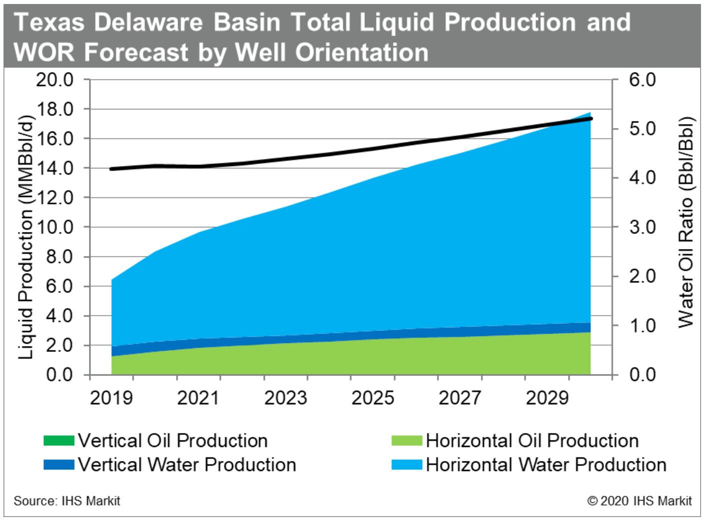


Figure 2-11: Texas Delaware Basin Total Liquid Production and WOR Forecast

We note that both oil and associated gas production require power usage as these products are transported from the well head to markets. Much of this power use occurs in the gathering systems, which deliver products to central transmission points.

From Figure 2-11, we see that both oil and water production from horizontal wells will dominate total liquid production as horizontal wells will be drilled exclusively in this region. WOR increases from 4 to nearly 5 by the end of the forecast period.

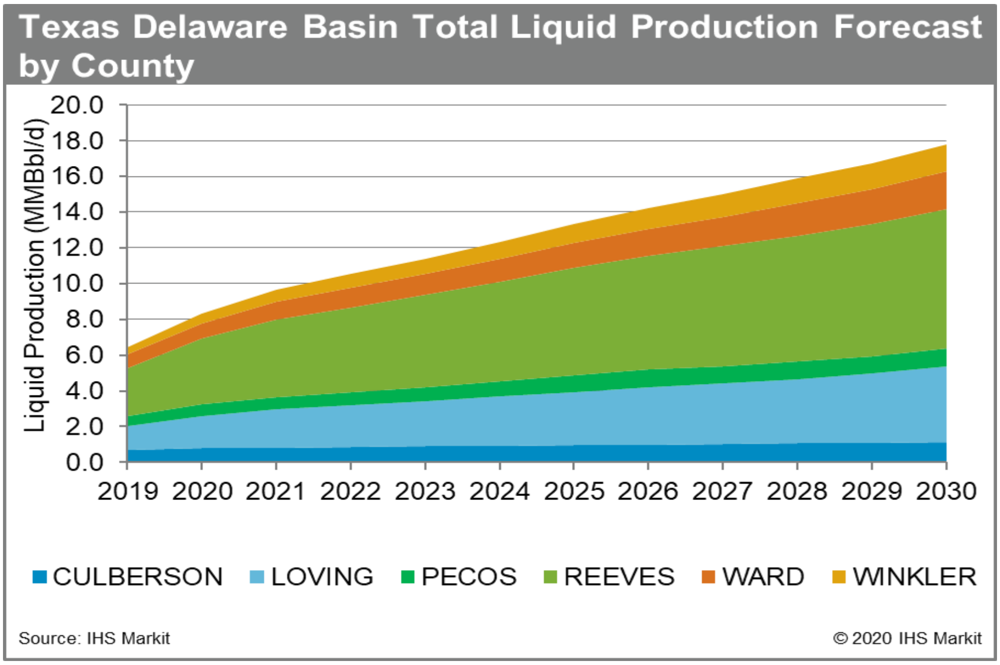


Figure 2-12: Texas Delaware Basin Total Liquid Production by County

Reeves and Loving Counties are the two main drivers for liquids volume gains in this region, (See Figure 2-12). We see higher quality areas in these counties, and the strategy of current operators in the region is to prioritize development of high-quality blocks and counties with abundant drilling opportunities; hence these counties will stand out in the current drilling boom.

2.2.3.2 Midland Basin

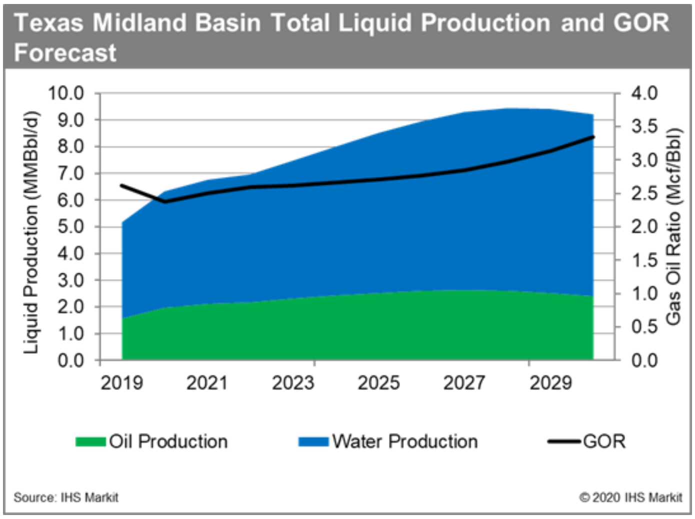


Figure 2-13: Texas Midland Basin Total Liquid Production and GOR Forecast

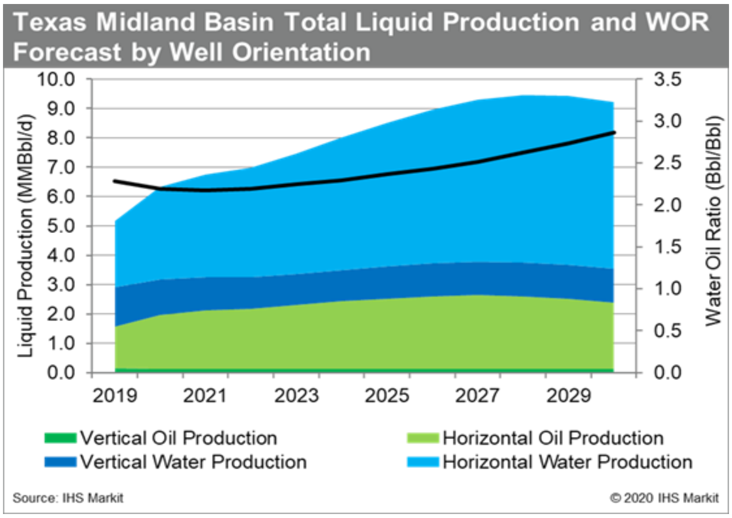


Figure 2-14: Texas Midland Basin Total Liquid Production and WOR Forecast

The Midland Basin includes seven counties with all, or a portion of each county located in the main Wolfcamp play fairway. Overall oil production is expected to rise to over 2 MMbbl/d by 2030, along with nearly 7.5 MMbbl/d water production as shown in Figure 2-13 and Figure 2-14. Similar to the Delaware Basin, Midland Basin's GOR is gradually increasing from 2.5 to 3.3 Mcf/bbl by 2030, which means that more gas will be produced relative to the increasing oil production.

From Figure 2-14, we see that both oil and water production from horizontal wells will dominate total liquid production as horizontal wells will be drilled exclusively in this region. WOR increases from 2.2 to nearly 3 by the end of the forecast period. Glasscock, Midland and Howard counties (Figure 2-15) are the top three counties for volume increases in this region. Operators in this region have established a solid foundation in this area, and this region continues to be an active and attractive unconventional play with great development potential.

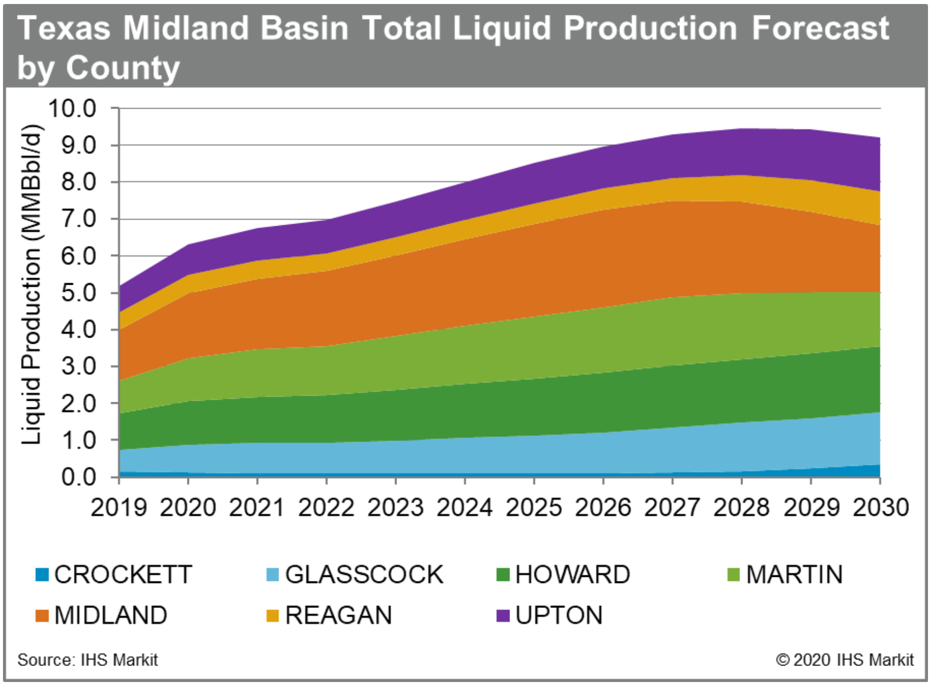


Figure 2-15: Texas Midland Basin Region Total Liquid Production by County

2.2.3.3 Central Basin Platform

The Central Basin Platform includes four counties, and it is a mature petroleum province with extensive vertical well production. There is minimal marginal upside for future oil production; however, overall liquid production is expected to remain stable between 3.0-3.5 MMbbl/d as oil production decreases and water production increases. (Figure 2-16).

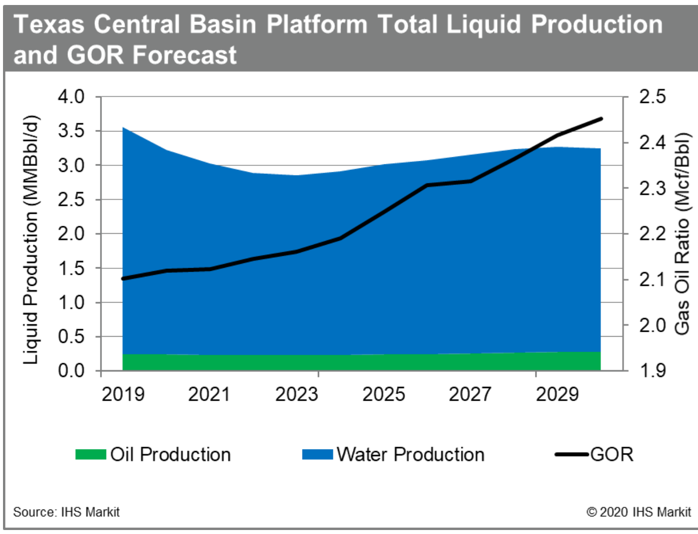


Figure 2-16: Central Basin Platform Total Liquid Production and GOR Forecast

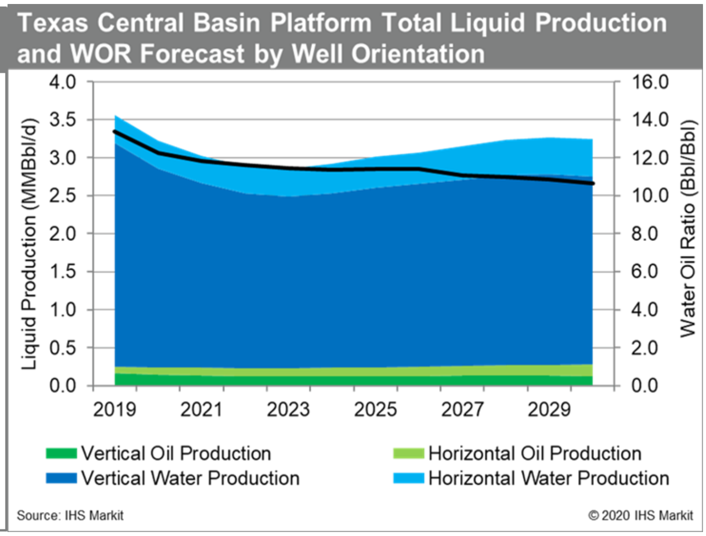


Figure 2-17: Central Basin Platform Total Liquid Production and WOR Forecast

More than 90% of total liquids production is water, as this region is already at the late stage of its lifecycle where excessive amounts of water are being produced. The WOR is already over 10 bblw/bbl (barrels of water per barrel of oil), as shown in Figure 2-17. The GOR in the region is gradually increasing from 2.1 to nearly 2.5 Mcf/bbl in 2030 (Figure 2-16). Andrews, Ector and Gaines Counties are the top three counties for production in this area as shown in Figure 2-18. As operators have already developed this region thoroughly, remaining locations available in this region are diminishing, and operations will center around maintaining currently producing wells.

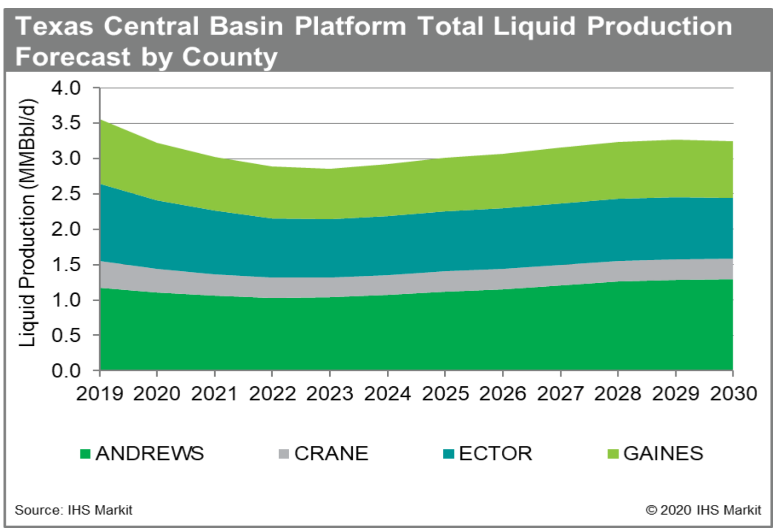


Figure 2-18: Texas Central Basin Platform Total Liquid Production by County

2.2.3.4 Fringe Area

The Fringe region includes seven counties and is considered to be peripheral around the core areas of the Permian Basin. Currently, this region has limited development capacities; overall liquid production will remain stable between 1.2-1.6 MMbbl/d through 2030. The GOR is mostly stable during the forecast period hovering around 4.5 Mcf/bbl by 2030 (Figure 2-19 and 2-20), which means additional gas production from the region.

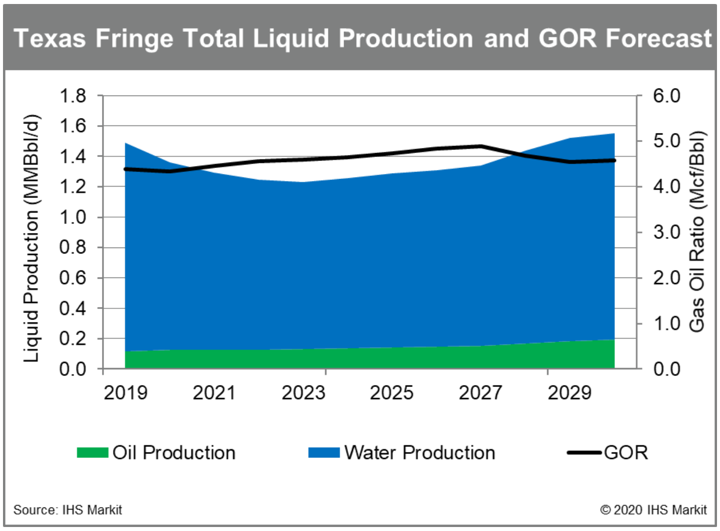


Figure 2-19: Fringe Area Total Liquid Production and GOR Forecast

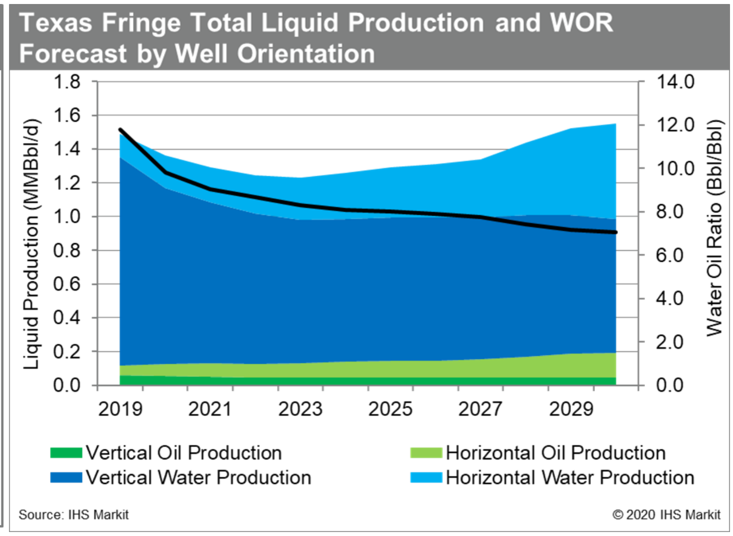


Figure 2-20: Fringe Area Total Liquid Production and WOR Forecast

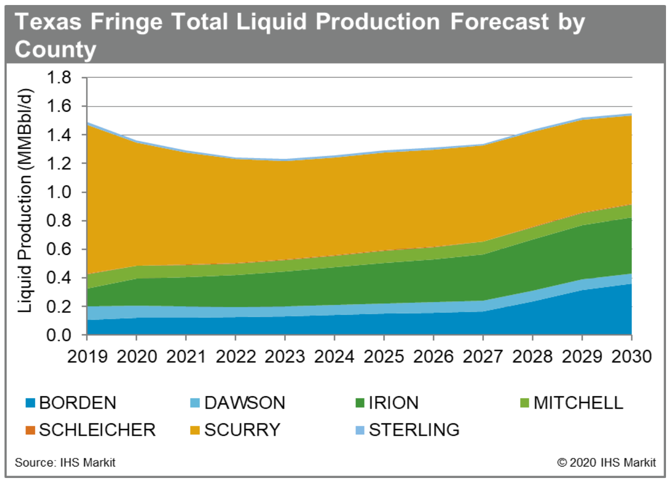


Figure 2-21: Fringe Area Total Liquids Production by County

Over 90% of total liquids production is water as this region is in the late stage of its lifecycle. The WOR is diminishing slightly to under 8 bblw/bbl by 2030 as shown in Figure 2-20; however, it continues to remain high. Sterling, Scurry, and Irion counties are the top 3 counties for production in this area shown in Figure 2-21. Operators are expected to be still exploring development in this region, but remaining locations in this region are quite limited.

2.2.4 Production Forecast Conclusions

Two key regions are the main drivers of long-term power demand growth. Most of future liquids production will come from wells located exclusively in the Delaware and Midland regions. In the short term, oil production will contribute greatly to overall liquid production; but in the long run, with the high and gradually increasing WORs, water production would be the long-term driver of overall liquids production.

Horizontal wells will dominate future E&P activity. The Central Basin Platform area is considered to be mature, and the Fringe area in Texas has limited upside potential for E&P activity. Therefore, nearly all the remaining locations in the Permian Basin are expected to be horizontal wells for long term growth. Related power demand as well as pumping profile changes should be expected.

Existing wells are equally important to future power demand. New wells brought online each year will remain consistently stable while cumulative well counts will increase. With more and more wells entering the later stage of well life, WOR will increase and water production would be the prevailing liquid in the long run.

2.3 Upstream Operations Requiring Power

2.3.1 Upstream Value Chain

2.3.1.1 Overview

The upstream oil and gas value chain includes the activities involved with the exploration, development, and production of oil and gas, most of which occurs near the well head with several wells occupying a single well pad. Exploration is targeting unknown or emerging plays. Following the initial drilling/development of wells, oil, gas, and water production from those wells flow to a central tank battery in the well pad to be separated from each other. Oil and gas are sold separately through pipelines, produced water is removed and disposed to SWD wells or recycled for reuse. In some instances, water or CO2 may be injected into mature wells in order to improve dwindling production, a process called Enhanced Oil Recovery (EOR). In the Permian Basin, most wells that use EOR are vertical wells. A schematic can be seen below in Figure 3-1 that shows equipment used in the upstream sector.

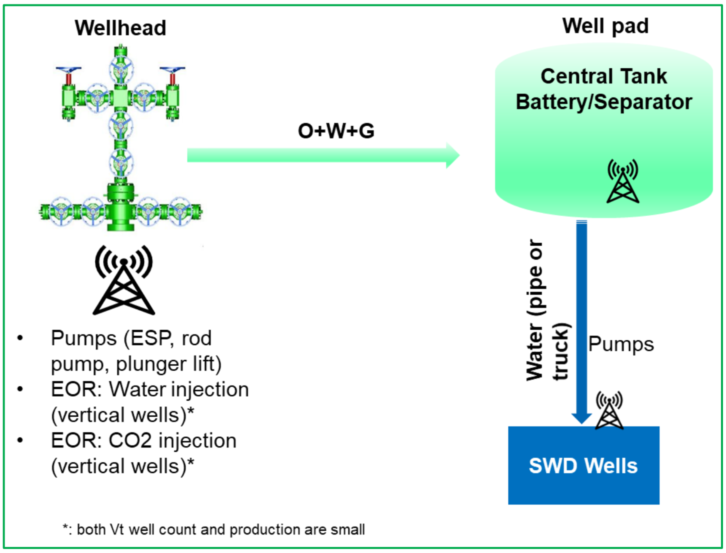


Figure 3-1: Upstream Schematic

During production, water and other impurities are produced along with the oil and gas. Pumps are used to drive the production from the subsurface. Pumps require significant amounts of electrical power to operate well sites and also have metering and monitoring systems to keep track of production and to monitor for malfunctions.

Water production typically increases as the field matures and production dwindles from individual wells. Water must be separated from the oil or gas stream and then sent for disposal in a SWD well. The water can be transported by pipeline or truck. Water transport and disposal also utilizes electric power to operate the equipment.

Other impurities may be found in gas, which will need be separated either at the central tank battery prior to transportation by gathering pipeline or at a gas plant before transportation through trunk pipelines to market.

Equipment used in the upstream value chain includes drilling and completion equipment, camp power, the central tank battery,[3] pumps used in artificial lift, EOR injection equipment, pumps used for SWD, and gathering lines. Figure 3-2 shows the different power needs and uses for equipment onsite.

[3] A central tank battery is a group of tanks that are connected to receive crude oil production from a well or producing lease. In the tank battery, the oil volume is measured and tested before pumping into the pipeline system.

Application	Genset	Grid	Power Required – Interview & Research		Comments
			Source 1	Source 2 & 3	
Drilling & Completion	✓				• Nearly all use portable gensets rather than grid power, given frequent movement of rigs from site to site
Camp Power	✓	<10%		• ~2 kw/worker	• Power needs require electricity, but workers can live in fixed buildings or camps with grid power
Artificial Lift	New area (no grid available)	✓	• 10-15 HP/100Bbl Liquid (oil & water) per day	• 150 kw/ESP • 75 kw/Top pump • <100kw/well • Related to depth	• Large amount of power can come from grid, but most use self generation prior to connecting to the grid
Tank Battery/Separator	New area (no grid available)	✓	• 500 HP per 10,000 Bbl fluids (oil & water) per day		• Difficult to identify if on the grid
Salt Water Disposal Well	New area (no grid available)	✓	• 300-500 HP per 10,000 Bbl of water per day	• 1000kw/large SWD • 10kw/small SWD	• Lage SWD well handles 400 – 500 oil producers • Small SWD well handles 20 – 30 oil producers

Figure 3-2: Upstream Power Uses

The equipment at a wellsite can be run either on grid power or gensets located onsite. Operators must weigh several factors when determining which method of power that they plan to use. Factors include grid access, time constraints for grid access, local availability of power infrastructure, and easement and access issues. For many operators, the electrical grid is the most preferred form of power access as it is generally the least expensive option. In the areas of remote and emerging plays, or during initial operations, where no electric grid is available, operators must rely on multiple sets of generators (commonly referred to as gensets). Gensets are typically leased and run on diesel fuel or gas power, which leads to higher operating costs and emissions. Unlike grid power, the large capacity gensets are limited in the market, and thus may not meet large demand from pad production. Some E&Ps plan far in advance to have grid power available for operations.

2.3.1.2 Artificial Lift Systems

Wells located in the major unconventional plays – including Permian Basin plays, all eventually require artificial lift for production. Wells in the Permian Basin tend to transition earlier to artificial lift than other plays, sometimes even in the first month of production. Options include gas lift or pumps. Gas lift injects gas produced from the well to drive production and works best in wells with high gas content.

There are several types of pumps used for lift which include rod pumps, plunger lift, and Electrical Submersible Pumps (ESPs). The power usage in production is variable based on the amount of oil and/or water produced and the required horsepower to do so. Typically, ESP wells will have the most power demand, but perform almost two times better than topside pumps, although these are limited to liquids production. Different forms of artificial lift have different characteristics, such as maximum volumes, handling of gas or sand, and the maximum temperature which it can handle.

For example, in Midland County, around month eight of production, the typical well is shifted from gas lift to an ESP system to maximize production as a well naturally declines. ESPs are more costly, and thus will be used when only necessary to assist with production. Once daily production has fallen below certain volumes, operators will install rod pumps for the remainder of the productive life of the well (see Figure 3-4).

2.3.2 Upstream Calculations and Methodologies

Determining artificial lift usage: In order to determine the artificial lift demands for the different regions and counties studied, we generated a typical or average single well production profile for each county. The first two years of data production was then compared to a proprietary database containing some artificial lift data. From this data, general percentages and trends of artificial lift were developed on a per county basis and were associated with the single well production profile (Figure 3-4). While there is a variability of artificial types and timing of implementation in each county, we used the data to generalize a typical profile that could be applied to the production forecast. Determining artificial lift types is important since each type requires different power demands.

The artificial lift model we created produced a pattern of artificial lift methods as shown below in Figure 3-3.

Figure 3-3 Artificial Lift Schematic

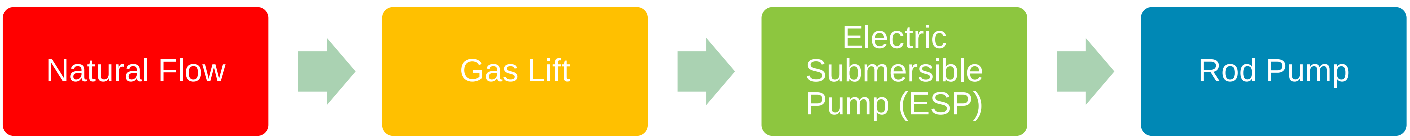


Figure 3-4 shows the typical production profile for a well in Midland County with the methods of artificial lift applied during each phase of the well's life. As can be seen in the graphic, no pump is needed during a brief time (during the first month) when the natural flow of the well drives production. Around the end of month 4, production peaks, and gas lift becomes the primary method of driving production from the well.

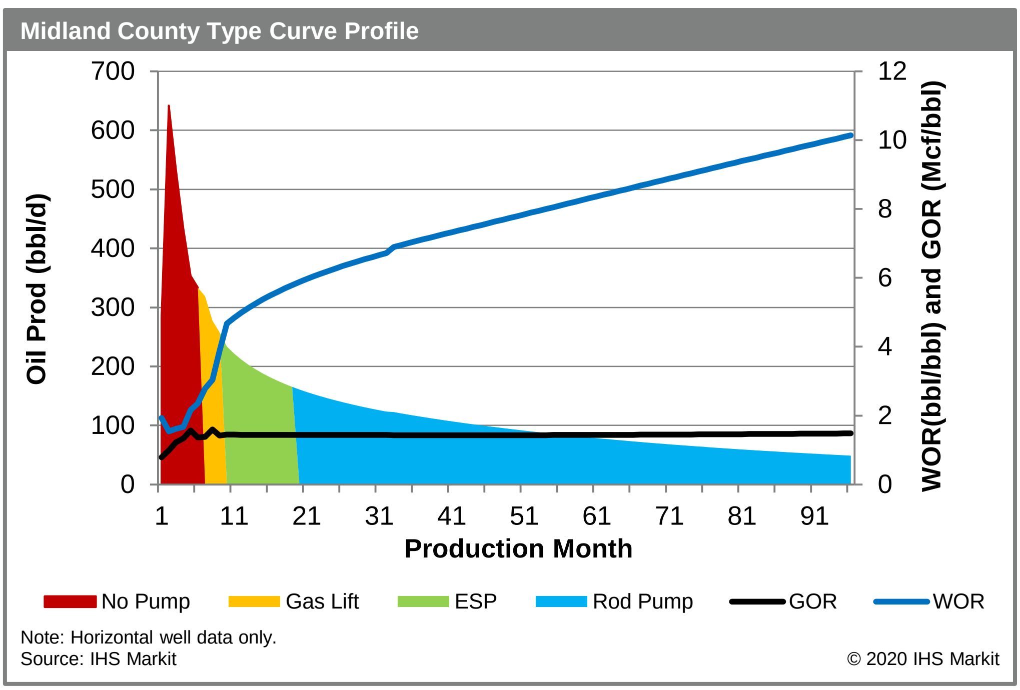


Figure 3-4 Example Type Curve -- Midland County

Gas produced at the wellhead is injected into the well through a gas lift to drive liquids production. Gas flow works best for wells with high GORs. Operators select their methods and timing of artificial lift based on their own targets, needs, and equipment availability. The data shown is based on analysis of recent wells in the Permian Basin.

These county level production profiles are then input into a model, which then applies a percentage of each artificial lift type to the future production forecast through 2030 (see Figure 3-5).

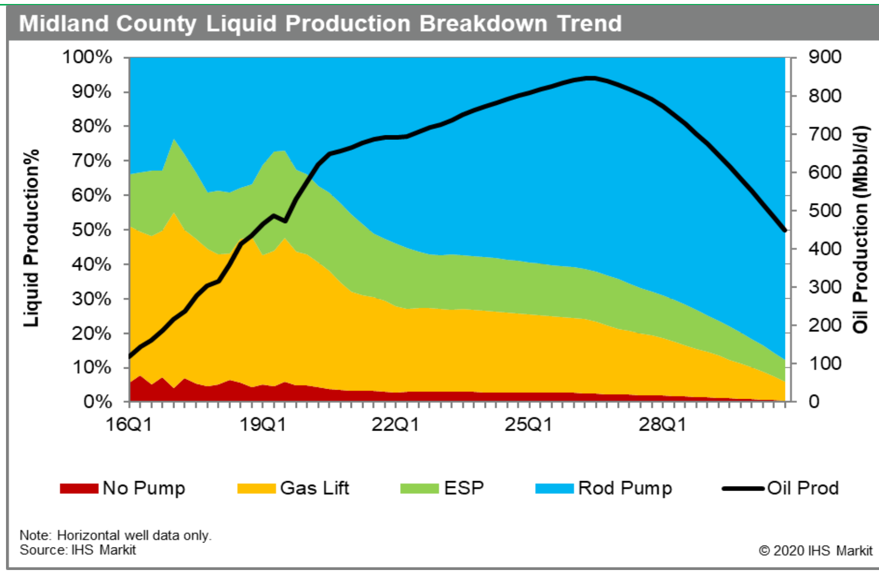


Figure 3-5: Example Liquids Production through 2030 -- Midland County

Calculation of power requirements: Key drivers of the power requirement for artificial lift systems include fluid rates, fluid weights, well depth, casing/tubing size, pump intake pressure, GOR, and wellhead pressure. Figure 3-6 below details the drivers of artificial lift systems.

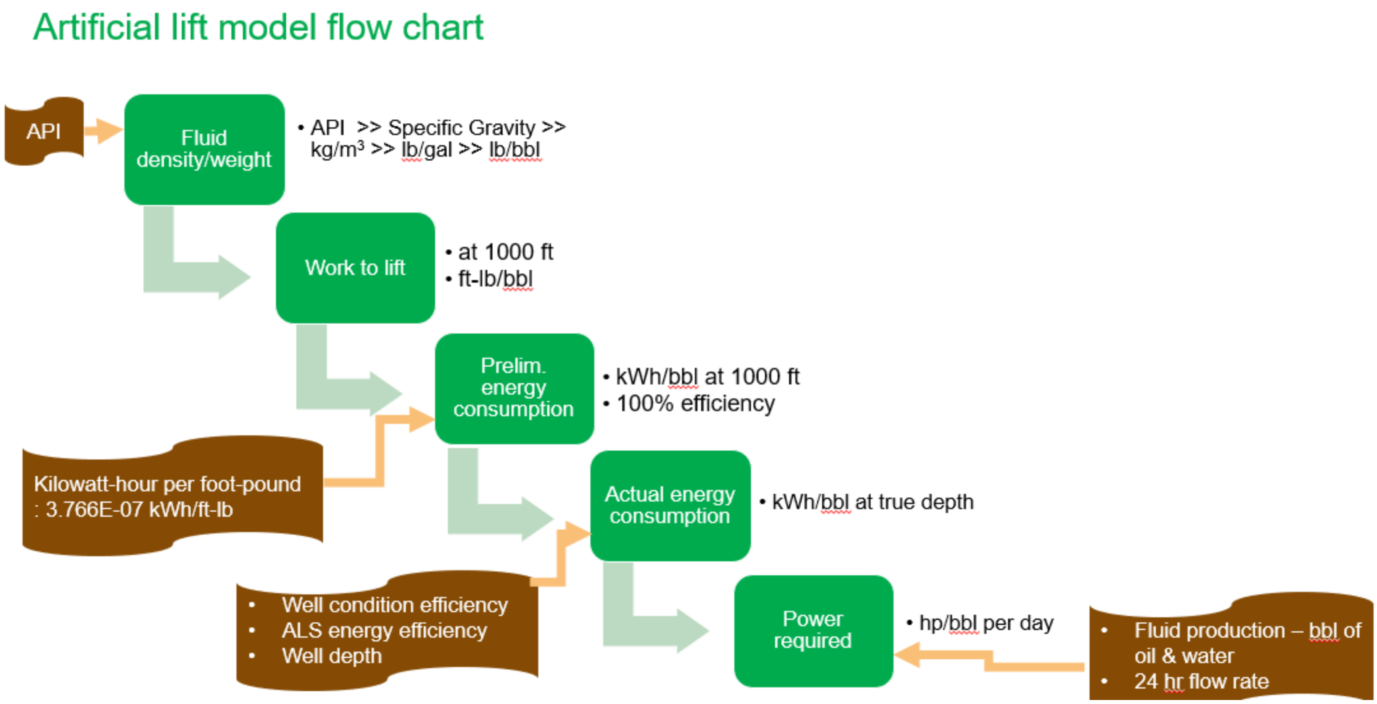
Figure 3-6 Key Drivers of Power Requirement for Artificial Lift Systems

	Drivers	Comments
Model Input	Fluid Rate	Higher fluid rate needs higher horsepower pump in terms of barrels of fluid per day
Model Input	Fluid Weight	Heavier fluid weight needs higher horsepower pump in terms of API gravity or fluid density
Model Input	Depth of Well	Deeper well need higher horsepower pump in term of true vertical depth of well in feet
Efficiency of Well Condition	Casing/Tubing Size	Larger casing/tubing size needs higher horsepower pump
Efficiency of Well Condition	Pump intake pressure and well head pressure	Higher intake pressure needs lower horsepower pump needed. Higher wellhead pressure needs higher horsepower pump needed.

After calculating the artificial lift needs based on different well parameters for each well, we were then able to apply a power usage for each barrel of liquids (oil + water) pumped from the well.

Using data for these variables and relationships among them, we then determined the horsepower need per barrel per day. The process is first visualized in the Figure 3-7. Then the first three steps are visualized and explained first, then finally, steps 4 and 5 are visualized and explained.

Figure 3-7: Artificial Lift Model Flow Chart

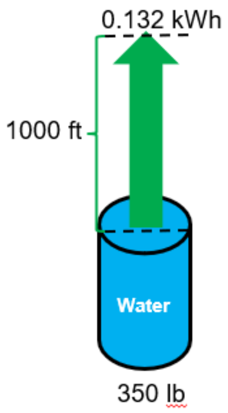


An artificial lift conversion factor was calculated through several steps:

Step 1: Calculate the lift factor

a. The fluid weight is converted to weight per barrel (lb/bbl)
b. The work to lift the fluid 1000 feet is calculated (ft-lb/bbl)
c. The Energy consumption for the lifting action is calculated (kWh/ft-lb)

Lift Factor Calculation Example – Step 1



Assumes a fluid density of 0.0361 lb/in³

(density of fresh water)

Fluid weight

0.0361 lb/in³ × 241 in³/gal = 8.34 lb/gal

8.34 lb/gal × 42 gal/bbl = 350 lb/bbl

Work to Lift at 1000 ft

350 lb/bbl × 1000 ft = 350,000 ft-lb/bbl

Energy Consumption

350,000 ft-lb/bbl × 3.766 × 10^{-7} kWh/ft-lb[2]

= **0.132 kWh/bbl**

Figure 3-8: Example of Artificial Flow Lift Factor Calculation

For Fluid density / weight (weight or specific gravity is defined as units or degrees of API), figures were converted into specific gravity, then kg/m³, then lb/gal, and finally lb/bbl. Permian light oil typically has an API of 40-45. The table below shows how API relates to these variables (see Table 3-1 for specific gravity API conversion values), before the conversion from gallons to barrels. Water has an API gravity of 10 and most Permian oils have an API of 35-48.

Table 3-1 Specific Gravity Calculations

Degree API	Specific Gravity	Weight	
		[lb/US gal]	[kg/m³]
1	1.068	8.894	1067
5	1.037	8.633	1035
8	1.014	8.447	1013
10	1.000	8.328	998.9
15	0.9659	8.044	964.8
20	0.9340	7.778	933.1
25	0.9042	7.530	903.2
30	0.8762	7.297	875.3
35	0.8498	7.078	848.9
40	0.8251	6.871	824.3
45	0.8017	6.677	800.8
50	0.7796	6.493	778.8
55	0.7587	6.319	757.9
60	0.7389	6.154	738.1
70	0.7022	5.848	701.5
80	0.6690	5.572	668.3
90	0.6388	5.320	638.1

The work lift was calculated at 1000 feet bringing the variable measured to units of ft-lb/bbl.

Step 2: Determine the Lift Factor in kWh/bbl per 1000 ft

Preliminary energy consumption is calculated using kilowatt-hour per foot-pound (3.766E-07 kWh/ft-lb, assuming 100% efficiency). The variable measured was now in units of kWh/bbl at 1000 feet (Table 3-2).

Table 3-2 Lift Factor Calculations

Lift Factors (kWh/bbl per 1000 ft)	Fluid API Gravity			
Efficiency of Well Condition (tubing size, reservoir pressure etc.)	**10 (fresh water)**	**20**	**30**	**40**
100%	0.132	0.123	0.116	0.109
75%	0.176	0.164	0.154	0.145
50%	0.264	0.247	0.231	0.218
25%	0.528	0.493	0.463	0.436

Step 3: Determine Lift Factor in HP/bbl per 1000 ft

The energy consumption now must be converted from an energy metric, such as kWh, to a power metric, such as HP or KW.

Table 3-3: Lift Factor Calculations

Lift Factors (HP/bbl per 1000 ft)	Fluid API Gravity			
Efficiency of Well Condition (tubing size, reservoir pressure etc.)	**10**	**20**	**30**	**40**
100%	0.177	0.165	0.155	0.146
75%	0.236	0.220	0.206	0.194
50%	0.354	0.331	0.310	0.292
25%	0.708	0.661	0.621	0.584

Step 4: Identify the Energy Efficiency of the Different Artificial Lift Methods[4]

Actual energy consumption depends a few variables, including well depth, which is usually much greater than 1,000 feet. It also depends on well condition and ALS efficiency. The most relevant ALS efficiencies are 58% for beam/rod pump and 48% for ESPs.

Table 3-4 Energy Efficiency of Pumps

Pump Type	Energy Efficiency of Artificial Lift
Beam/Rod Pump	58%
Hydraulic Pump	16%
Gas Lift	15%
ESP	48%

[4] Source: Society of Petroleum Engineers https://petrowiki.org/File:Vol4_Page_445_Image_0001.png, https://petrowiki.org/PEH:Artificial_Lift_Systems

Step 5: Calculate Using the Well Depth, Rate and Efficiency for the Artificial Lift Type

The variable measured was now in units of kWh (or HP) per bbl at true vertical depth. Finally, there is power required, which depends on the fluid production (oil and water) in a 24-hour period. The variable measured was now in units of HP/bbl/d. For ease of communication, we chose to measure power demand in HP per 100 bbl/d. For this step, the well was determined to be a 9,500 foot well with 100 bbl/d of production yielding a value of 14 HP for rod pumps and 17 HP for ESP which was generally applied to power requirements for each 100 bbl/d of fluid production (Table 3-5) at 75% efficiency.

Table 3-5 HP requirements of Rod Pumps and ESPs

Rod Pumps				
HP required for 100 bbl/d at 9,500 ft	Fluid API Gravity			
Efficiency of Well Condition (tubing size, reservoir pressure etc.)	10	20	30	40
100%	12	11	11	10
75%	16	15	14	13
50%	24	23	21	20
25%	48	45	42	40
ESP				
HP required for 100 bbl/d at 9500 ft	Fluid API Gravity			
Efficiency of Well Condition (tubing size, reservoir pressure etc.)	10	20	30	40
100%	15	14	13	12
75%	20	18	17	16
50%	29	27	26	24
25%	58	55	51	48

After all calculations were complete for a well with 9,500 foot depth and 100 bbl/d liquids production, results were validated by our experts and several comments from industry contacts; these assumptions were concluded to be the best for the power calculation.

Application of power requirements to historical and forecasted production: These steps and industry conversations determined that rod pumps need 14 HP per 100 bbl/d for rod pumping, but 17 HP per 100 bbl/d is needed for ESPs. Finally, we used the split of ESP vs. rod pumps for horizontal and vertical wells by month to determine electricity requirements. In January 2016, this split was quite evenly divided between ESP and rod pump for horizontal wells, but it was 100% rod pump for vertical wells.

In addition to the power requirements for artificial lift, SWD pumps and tank facilities are also consumers of electric power at the well site. In the Permian Basin and other plays located in southern states, reciprocating plunger pumps are the most commonly used pumps for SWD. IHS Markit identified 49 models of reciprocating plunger pump specifications that are manufactured by Weatherford and MYERS. Based on these specifications, IHS Markit developed a SWD pump model and calculated the horsepower per fluid rate (Figure 3-9). Specifications include the rated capacity in gallons/minute and horsepower. Using this information, a rate in horsepower per barrels per day (HP per bbl/d) was determined. After discussions with industry and internal experts, the conversion factor of 4 HP per 100 bbl/d of water was determined to be the best estimate.

Salt water disposal pump designed rating conversion factor calculation

1. Reciprocating plunger pumps are most commonly found in SWD service in the Permian and other plays in southern state. [1]
2. Identified 49 models of reciprocating plunger pumps' specification manufactured by Weatherford and MYERS.[2] [3]
3. Calculated the Horsepower per fluid rate based on those specification.

Calculation Example

Weatherford Model W200 L

Specification:

API Calculated Rated Capacity (Medium Case) (Gallon per Minute): 253

Designed Horsepower (HP): 200

Step 1: Convert Capacity to Barrel per Day

$$\frac{253 \text{ gallon/minute} \times 60 \text{ minute/hour} \times 24 \text{ hour/day}}{42 \text{ Gallon/Barrel}} = 8{,}674 \text{ Barrel/day}$$

Step 2: Calculate the Designed Rating Conversion Factor

$$\frac{200 \text{ Horsepower}}{8674 \text{ Barrel/d}} = 0.0231 \text{ HP per barrel/d}$$

Results of 49 Models of Reciprocating Plunger Pumps

Average Low Case Designed Rating (HP/bbl per day)	Average Medium Case Designed Rating (HP/bbl per day)	Average High Case Designed Rating (HP/bbl per day)
0.23	0.05	0.04

After discussion with industry and internal expert, we conclude the conversion factor of **4 HP per 100 bbl/d** is the best estimate SWD energy calculation.

Figure 3-9: Saltwater Disposal Pump Schematic

As for tank batteries, proprietary data and industry contacts indicate that separators and other equipment require 1 HP per 100 bbl/d, but water recycling requires 3 HP per 100 bbl/d.

Figure 3-10 on the next page provides a summary of the upstream power conversion assumptions used to convert oil and water production to power demand when any type of pump is required. Using the values presented in Figure 3-9 we applied these to the historical and forecasted production profiles of each county as follows:

Oil and water production from vertical wells – applied rod pumps for 14 HP/100 bbl 100% of the time

Oil and water production from horizontal wells – applied the respective HP values to the artificial lift percentage splits described on part "Determining artificial lift usage" section of this methodology. Power applied includes the following:

Natural flow and gas lift – 0 HP/100 bbl

Rod pump – 14 HP/100bbl

ESP – 17 HP/100 bbl

For all liquids – 1 HP per 100 bbl

For water disposal and transport – 4 HP per 100 bbl

When applying power requirements to the production history and forecast, we converted HP into kW so that we could eventually compare oil and gas power demand with actual historical electrical load data. A discussion of the comparison of these relationships between actual power use and oil and gas activity is set forth in Section 3.2 of this report.

Figure 3-10: Upstream Power Conversions Summary

Oil and Water Forecast Production Data

×

Percent of Rod Pump and ESP Split

×

Items	Fluid	Electric Horsepower per 100 bbl/d
Rod Pump	Oil and water	14
ESP	Oil and water	17
Salt Water Disposal	Water	4
Tank (Facility) – Separator and others	Oil and water	1
Tank (Facility) – Water Recycling related	Water	3

×

Percent of Upstream Electricity Demand On Electricity Grid

=

Energy Demand on Grid (in Megawatts) for Rod Pump, ESP, SWD, Tank(Facility) by County, by Month

2.3.3 Application to History

In order to calculate the total upstream electricity required on a per county basis, the main drivers of power use in the upstream sector were calculated and converted into electricity demand in megawatts. The rates of total oil and water production, the production rates from ESPs and rod pumps, and SWD well oil and water rates for ESPs and rod pumps were calculated for each month and then converted into electricity demand in megawatts. Table 3-6 shows the calculated megawatts based on historical inputs by county for August 2019.

Table 3-6: Calculation of Upstream Energy Needs by County

County	Date	Sum Oil+Water Rate (Mbbl/d)	Sum ESP Oil+Water Rate (Mbbl/d)	Sum Rod Pump Oil+Water Rate (Mbbl/d)	Sum SWD Water Rate (Mbbl/d)	Total Upstream Electricity (Megawatts) - IHS
ANDREWS	8/1/2019	1,126	93	1,015	1,020	179
BORDEN	8/1/2019	103	-	103	85	16
CRANE	8/1/2019	360	-	360	343	58
CROCKETT	8/1/2019	133	0	133	116	21
CULBERSON	8/1/2019	686	193	81	609	70
DAWSON	8/1/2019	94	0	94	85	15
ECTOR	8/1/2019	1,029	1	1,028	977	166
GAINES	8/1/2019	899	1	897	838	144
GLASSCOCK	8/1/2019	561	48	389	412	72
HOWARD	8/1/2019	973	7	751	761	126
IRION	8/1/2019	131	3	65	93	13
LOVING	8/1/2019	1,295	38	522	974	120
MARTIN	8/1/2019	868	192	301	561	92
MIDLAND	8/1/2019	1,342	303	481	834	142
MITCHELL	8/1/2019	95	0	95	88	15
PECOS	8/1/2019	545	91	354	462	77
REAGAN	8/1/2019	430	14	251	308	47
REEVES	8/1/2019	2,474	679	343	1,982	244
SCHLEICHER	8/1/2019	5	0	5	4	1
SCURRY	8/1/2019	1,036	0	1,036	999	168
STERLING	8/1/2019	16	0	16	14	3
UPTON	8/1/2019	704	102	480	496	94
WARD	8/1/2019	794	107	588	647	115
WINKLER	8/1/2019	391	38	322	333	59

2.4 Midstream Operations Requiring Power

2.4.1 Midstream Value Chain

2.4.1.1 Overview

Production from the well site must follow an integrated supply system before it can be sold. In this process, liquids are separated from more volatile gaseous components. Produced liquids include both water and oil, which must also be separated before the oil can flow through a pipeline.

Produced natural gas is naturally 'wet' meaning that in addition to dry methane, it also includes hydrocarbon molecules heavier than methane. These associated hydrocarbons such as butane or ethane are known as natural gas liquids (NGLs) and sold separately. This process is described in detail later in the section.

Once oil, water, and wet gas are separated at the well site or well pad, the oil and wet gas production is taken by local gathering lines to be commingled into groupings of wells or well pads at a central delivery point. Production may go through several aggregations from local to intermediate gathering as it is accumulated along the supply chain.

Production from vertical wells follows similar grouping methods, but due to their higher geographical density, the number of vertical wells included in a group is often significantly higher than for horizontal wells (Figure 4-1).

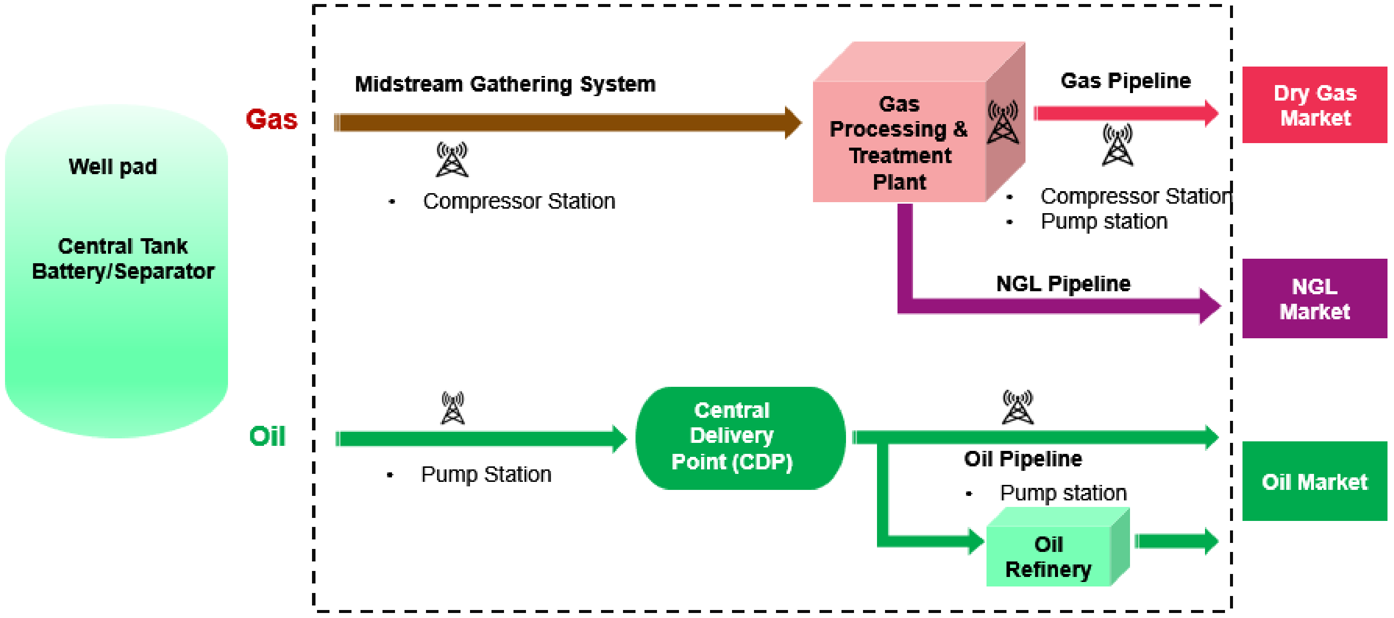


Figure 4-1: Production supply chain with power requirements

Once gathered locally, the oil and wet gas each follow their own supply chain. Oil moves toward long haul pipelines to eventually reach a refinery for processing into fuel and other petroleum products. Wet gas moves toward a gas plant for processing to extract NGLs and remove impurities (inert gases, such as hydrogen sulfide (H2S) or nitrogen). The resulting gas is nearly pure methane and is referred to as 'dry' gas. At this point, dry gas is ready for sale via a long-haul gas pipeline. Long-haul gas pipelines are used to deliver gas to surrounding regions, where it is then used for powering electrical plants, heating homes and fueling industrial processes.

Extracted NGL volumes, similarly to oil, are pumped via long-haul NGL pipelines for sales in nearby regions.

Facility Type	Rely heavily on grid power	Sometimes rely on grid power	Don't rely on grid power	Comments
Refineries	✓			Few refineries in region. 18% of electrical equivalent power is expected to come from the grid.
Gas Treatment Plants		✓		Gas plants often connect to the grid when possible. Historically, larger plants (>50MMcf/d) that have huge energy requirements were more likely to be off the grid. This trend is changing, and when given the opportunity, plants will connect to the grid. However, compression operations are powered locally with gas turbines.
Compressor Stations and Gas Pipelines		✓		Demand from compressors is high as this is a major user of power. Compressors moving wet gas before reaching a gas processing plant are more likely to be on the grid. Long haul compressors have access to cheap processed gas within the pipelines and grid reliance is more common in East Texas.
Liquid Pipelines and Pumps	✓			Most pumps are powered by the grid. Pumps can be powered by diesel, but it is not efficient or cost effective.

Table 4-1: Grid power dependence by facility type

Energy is consumed in every step of this integrated supply chain process. The primary midstream energy consumers are local oil and wet gas gathering lines, intermediate lines for aggregating local volumes, long-haul lines to market, oil refineries, and gas processing plants Based on our research certain facility types rely more on electrical grid power than others (see Table 4-1).

2.4.2 Methodology

IHS Markit has estimated average power required for the transportation of oil, gas and NGLs, as well as power required for the operation of refineries and gas plants. There may be additional components of the midstream operations that draw power, but these components are too small to impact the overall forecast. Within the Permian Basin, the preponderance of midstream electric grid power is used by gathering systems and gas processing plants

2.4.2.1 Assessing County Power Requirements for Oil and Gas Transportation

IHS Markit modeled all three phases of the oil and gas transportation: local gathering, intermediate gathering, and long-haul. Local gathering lines are typically 6 inches in diameter or less, while intermediate gathering lines can range between 6 inches and 12 inches in diameter. Pipelines with diameters over 12 inches are used for long-haul transportation.

The hierarchical nature of the transportation system implies that well-level production must be determined before local and intermediate gathering throughputs can be estimated, which in turn are precursors for the long-haul throughput assessments. Once the average production from an individual well is determined, it is multiplied by the number of wells per grouping, or well pad, to arrive at the average production for a local or intermediate gathering node. IHS Markit applied 4 well pads or well groups per intermediate node.

Power consumption by local and intermediate gathering systems can be attributed to the counties that contain their starting nodes, as that is where the pumps or compressors used to push product through the pipeline are located. Production volumes that flow through these systems are also more localized to in-county volumes. Most gathering processes require access to grid power, since gas at this stage of the supply chain is not usable as fuel for gas turbines.

Unlike local and intermediate gathering systems, long-haul transportation accumulates volumes across the Far West Texas weather zone and other regions or states. Pressure requirements of long-haul systems are quite different as the speed for long-haul liquids transport is higher, usage is often lower, and routes are more optimized for differences in elevation. Gas long-haul pipelines do not experience the same required pressure differentials that are seen in the local and intermediate gathering systems, where gas must reach a pressure of 1,200 pounds per square inch (psi) before reaching the gas plant. Gas long-haul pipelines are also quite self-sufficient, using a portion of the transported gas as fuel, and thus are not expected to rely heavily on grid power.

Because long-haul systems rely more heavily on sequences of pumps or compressors over long distances as opposed to a single compressor or pump that only delivers volumes a short distance, IHS Markit differentiated its approach in estimating power requirements for gathering and long-haul transportation.

Once power requirements are estimated for a group of wells, for either local or intermediate gathering, they are prorated to a well-level, and then used to estimate power demand for the whole county, given the total number of wells as follows with Table 4-2 showing the parameters associated with gathering systems in each county.

Local gathering less than 6” diameter) = Total wells in a local well group x Local gathering kW per well

Intermediate Gathering (6”- 12” diameter) = Total wells in an intermediate well group x Intermediate gathering kW per well

County	Horizontal Wells per Pad	Vertical Wells per Delivery Point	Number of Wells Per Local Gathering	Number of Wells per Intermediate Gathering
Loving	2.4	10	4.1	16.5
Winkler	1.6	10	8.6	34.5
Ward	1.7	10	7.8	31.3
Reeves	1.8	10	4.0	15.9
Culberson	2.1	10	3.8	15.3
Midland	3.1	10	7.6	30.3
Howard	2.3	10	8.5	33.9
Martin	2.9	10	8.3	33.0
Glasscock	2.3	10	8.3	33.0
Upton	2.5	10	8.3	33.4
Reagan	2.5	10	8.0	31.9
Pecos	1.6	10	8.1	32.3
Crane	1	10	9.6	38.2
Ector	2.2	10	9.8	39.2
Andrews	2.4	10	9.5	37.9
Gaines	1	10	9.7	38.7
Dawson	1.2	10	9.7	39.0
Borden	1.7	10	8.5	34.1
Crockett	2.5	10	8.4	33.6
Irion	2.3	10	7.4	29.7
Sterling	1.3	10	9.7	38.9
Mitchell	1	10	10.0	39.9
Schleicher	2	10	9.5	37.9
Scurry	1.2	10	9.8	39.2

Table 4-2: Well groupings by county and type

While vertical wells are simply set to 10 per local grouping, horizontal well groupings were dynamically generated. That is, to account for differences between horizontal and vertical groupings, a well-weighted average of wells per group was calculated to then determine the average flow per pipe. The average flow per pipe was determined as the total county flow, and the average length per pipe - as total miles of pipe prorated to a single well as shown below.

County	2016	2019	2020	2025	2030
Andrews	1.83	2.38	2.43	2.68	2.93
Borden	1.20	1.71	1.76	2.01	2.26
Crocket	2.24	2.53	2.58	2.83	3.08
Culberson	1.48	2.12	2.17	2.42	2.67
Dawson	1.00	1.21	1.26	1.51	1.76
Ector	1.34	2.18	2.23	2.48	2.73
Gaines	1.00	1.00	1.05	1.30	1.55
Glasscock	1.81	2.33	2.38	2.63	2.88
Howard	1.51	2.33	2.38	2.63	2.88
Irion	2.06	2.26	2.31	2.56	2.81
Loving	1.86	2.40	2.45	2.70	2.95
Martin	2.15	2.89	2.94	3.19	3.44
Midland	2.57	3.12	3.17	3.42	3.67
Mitchell	1.00	1.00	1.05	1.30	1.55
Pecos	1.19	1.63	1.68	1.93	2.18
Reagan	2.27	2.55	2.60	2.85	3.10
Reeves	1.40	1.81	1.86	2.11	2.36
Schleicher	2.00	2.00	2.05	2.30	2.55
Sterling	1.28	1.26	1.31	1.56	1.81
Scurry	1.00	1.21	1.26	1.51	1.76
Upton	2.05	2.46	2.51	2.76	3.01
Ward	1.46	1.69	1.74	1.99	2.24
Winkler	1.21	1.61	1.66	1.91	2.16
Crane	1.00	1.00	1.05	1.30	1.55

Table 4-3: Average pipe length per well, in miles

Growth in the number of producing wells has peaked in the Delaware and Midland sub-basins and so has growth in the gathering infrastructure. Still, the gathering infrastructure is expected to increase as much as 8% and 7% per year in the Delaware and Midland sub-basins, respectively. However, as new well additions wane, gathering systems buildout will also slow down; nonetheless, growth is expected as far out as 2030.

The Delaware region is expected to expand from nearly 7,500 producing wells to over 20,000 by 2030, with much of this growth in new areas of the unconventional plays. As the plays in these areas expand, less need for new infrastructure will be required -- growth rates are expected to drop from 8% to just 2% by 2030 (Figure 4-2).

Delaware sub-basin - gathering growth rate

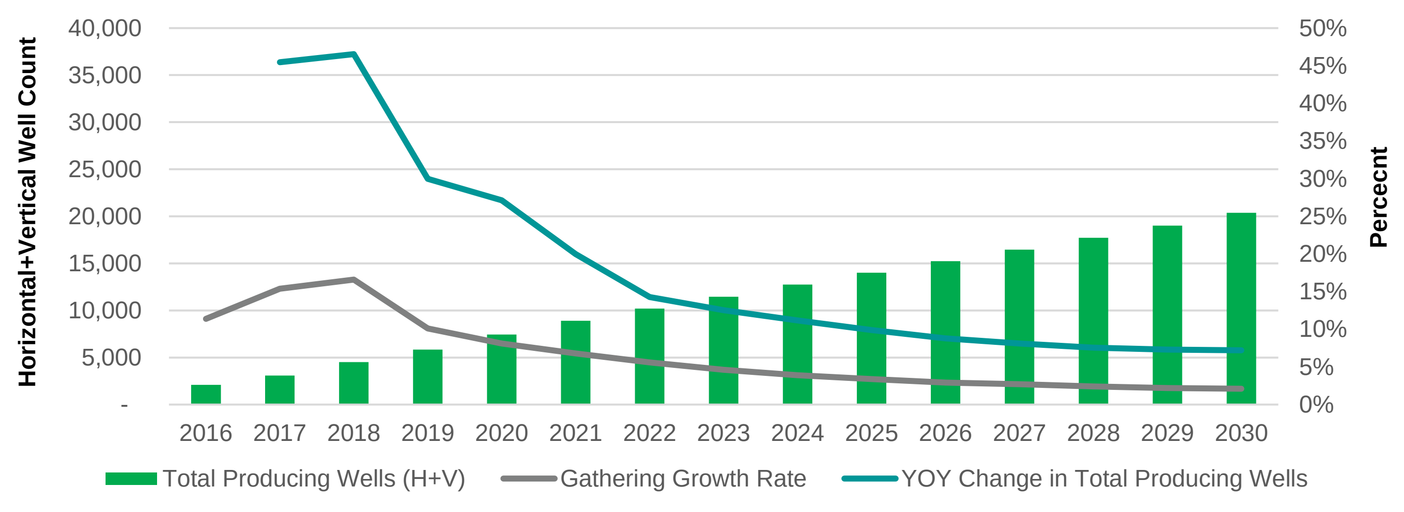


Figure 4-2: Expected gathering systems growth rate in the Delaware sub-basin

The Midland region is expected to expand from over 11,000 producing wells to 33,000 producing wells by 2030. Just like the Delaware Basin, most of this will be from the expansion in horizontal well development with growth rates dropping from 7% in present day to just 2% in 2030, as the region become more saturated with infrastructure (Figure 4-3).

Midland sub-basin - gathering growth rate

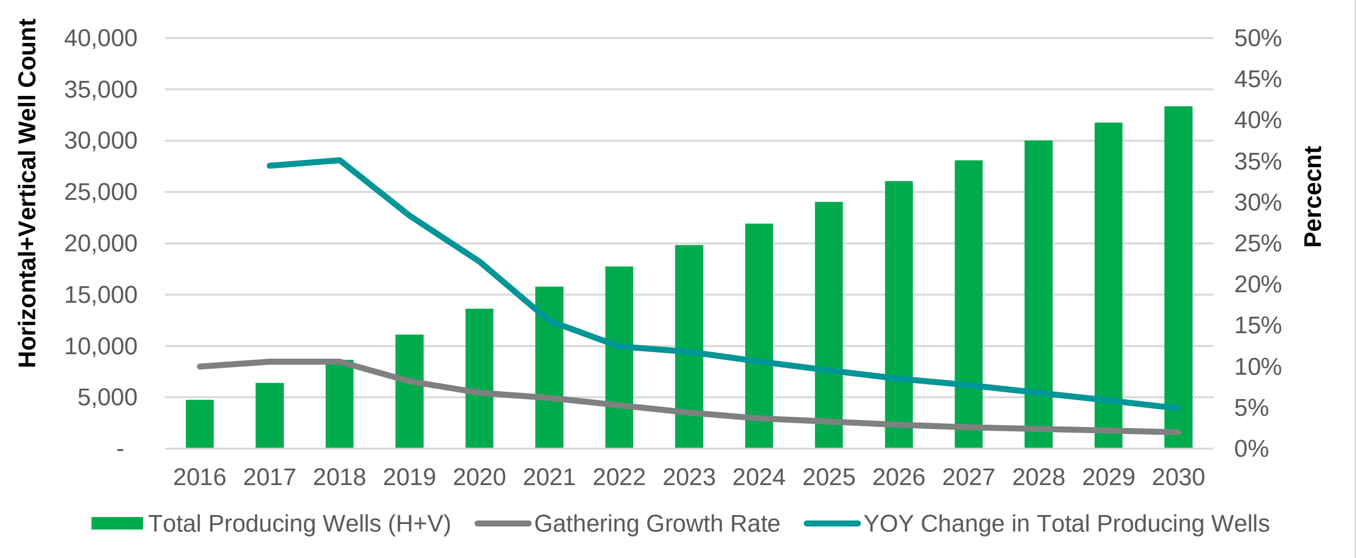


Figure 4-3: Expected gathering systems growth rate in the Midland sub-basin

While the other areas of the Permian hold more wells, the total number of producing wells is expected to drop by about 13,000 wells during the study period. Many of the conventional vertical wells in the area will be abandoned during this timeframe and any growth from active unconventional areas will be offset with the decommissioning of some gathering lines (Figure 4-4).

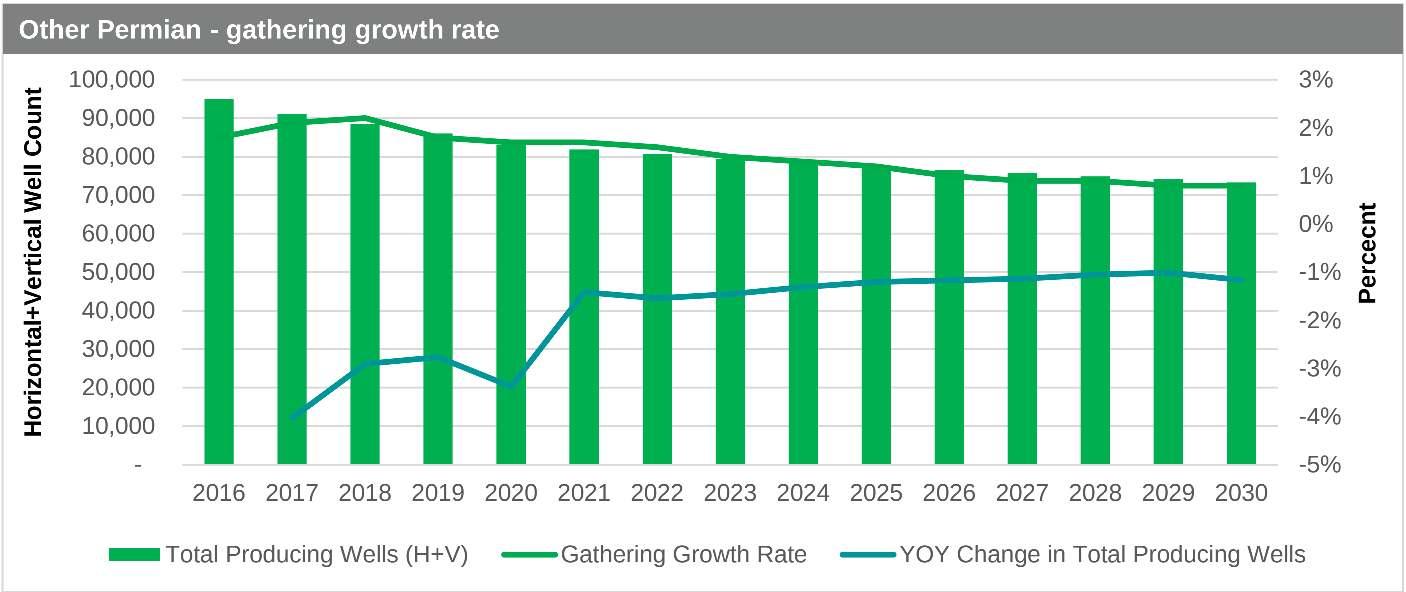


Figure 4-4: Expected gathering systems growth rate in other Permian areas

Power estimates for long-haul volumes are based on the total volumes traveling across a county, and the amount of power consumption per transported barrel (bbl) or barrel per day (bbl/d).

Long-haul (greater than 12" diameter) = total bbl/d x distance per long-haul pipe

Gas long-haul is considered to be powered by local gas in the long-haul sales line

Dry gas in the pipeline is used to fuel the compressor stations

Since current oil transport is expected to be sufficient to accommodate production increases through 2025, the total distance of long-haul pipelines is expected to remain constant in the near term. Thus, no adjustments were made about the total length of long-haul pipelines in each county throughout the forecast period.

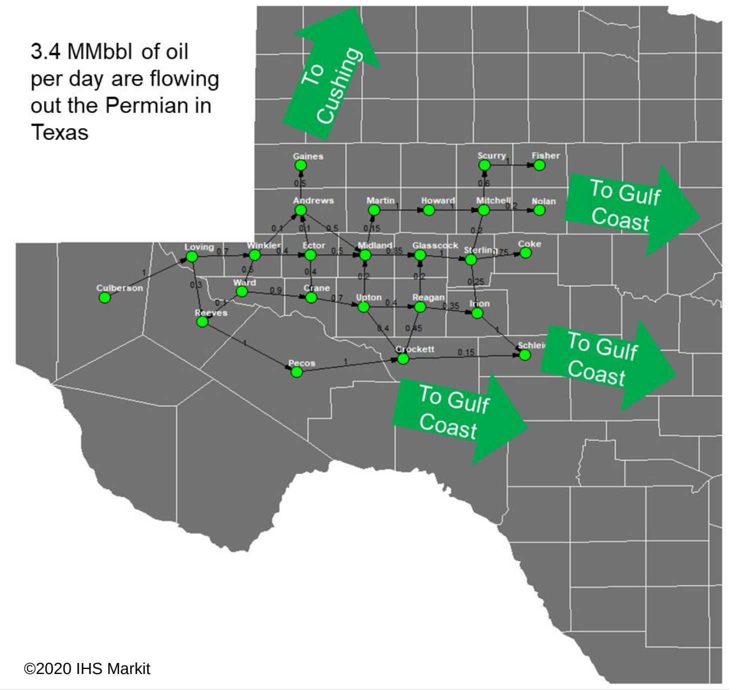


Figure 4-5: Cross-county oil flow network

Cross-county flows of production were assessed using nodal network analysis and a linear programming model to allocate the aggregated flows moving from one county to another.

The percentage allocations depicted in Figure 4.5 represent proportion of oil that flows from county to county. Nearly all the 3.4 million barrels per day (Mbbl/d) that flow through the region find their way to the Gulf Coast, with very few volumes moving northward into Cushing, Oklahoma. Most of the northern flows are outside of the Oncor's service area.

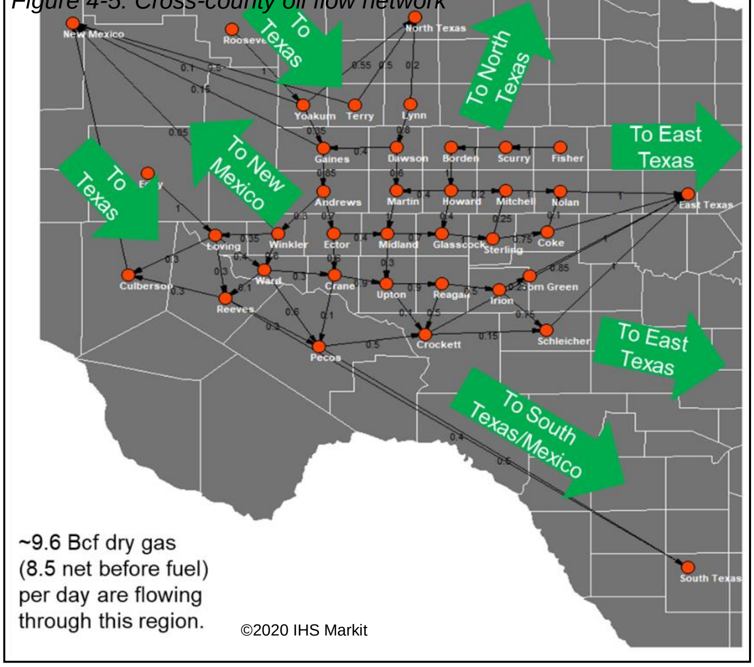


Figure 4-6: Cross-county gas flow network

Dry gas flows through the long-haul systems are much more complicated. Markets in San Juan, New Mexico have seen methane prices rise compared to the local Waha hub in northern Pecos County. Due to this price premium, volumes from the Texas side of the Permian are occupying pipe that would otherwise be used for New Mexico production. This is possible since those pipelines originate in Texas allowing Texas production first access to the capacity. In turn, New Mexico production is pushed into Texas with net flows being slightly positive into Texas. Some of the New Mexico production is also pushed south to Mexico, or East to Henry Hub, but some is simply pushed back into New Mexico after first traveling through the extent of the Permian.

Roughly 12% of the initial wet gas volume is lost in gas processing plants for NGLs and inert gases removal. Additionally, 11% is used up in the Permian region for local demand. Finally, 5.2% of the remaining gas volume is used up along the system as fuel for both the pipeline and other oil and gas operations. Individual demand from local power plants was considered in each county, with Ector County's power plant being one of the heaviest users. Although we have tracked these gas flows, our conversations with several internal experts suggests that long-haul gas transport relies very little on the grid but is fueled by a portion of the transported gas. On the other hand, long haul oil transport, which requires pumping does rely on the power grid and is included in the power requirements.

2.4.3 Assessing County Power Requirements for Oil Pipelines

In order to determine the amount of power consumed by an oil pipeline pump, IHS Markit first estimated the flow rate, and distance and diameter, to ultimately arrive at the pump pressure differential. IHS QUE$TOR, the industry standard for Pre-FEED (front-end engineering) studies, was utilized for calculation of the pump pressure differentials.

Elevation differentials are standardized per distance traveled. The power demand is re-assessed monthly, based on historical and forecasted average daily volumes, historical and future total pipeline length, and length-weighted average pipeline diameter for each county. Local and intermediate gathering systems are split into diameter categories, each average diameter reflects its respective category. Local gathering average diameters range from 3 to 5 inches, and intermediate gathering diameters average around 8 inches (Table 4-4). The power estimate figures for oil gathering are relatively low compared to the oil long haul and all the gas figures. This is because the pumps required to push 100 bbl/d may only be well under one kW.

County	Local Gathering Line Distance (miles)	Volume Per Local Gathering Line (bbl/d)	Intermediate Gathering Distance (miles)	Volume Per Intermediate Gathering Line (bbl/d)	Oil Gathering Power per Well (kW)	Total Oil Gathering Power per Well (MW)
Loving	0.2	716	0.7	2,864	0.343	0.728
Winkler	0.2	317	0.6	1,269	0.065	0.129
Ward	0.4	355	1.6	1,419	0.102	0.335
Reeves	0.3	623	1.1	2,490	0.347	1.288
Culberson	0.3	528	1.1	2,114	0.449	0.263
Midland	0.4	598	1.5	2,391	0.183	1.340
Howard	0.3	414	1.4	1,657	0.118	0.605
Martin	0.2	458	0.8	1,831	0.111	0.713
Glasscock	0.3	340	1.0	1,359	0.089	0.399
Upton	0.4	315	1.4	1,261	0.092	0.563
Reagan	0.3	182	1.3	726	0.046	0.257
Pecos	0.1	241	0.5	964	0.049	0.155
Crane	0.1	40	0.3	160	0.006	0.025
Ector	0.5	69	2.0	276	0.015	0.112
Andrews	1.0	112	3.9	449	0.030	0.295
Gaines	0.4	135	1.6	542	0.029	0.121
Dawson	0.3	63	1.2	253	0.013	0.016
Borden	0.6	251	2.3	1,002	0.067	0.044
Crockett	0.1	48	0.2	192	0.008	0.024
Irion	0.0	152	0.1	608	0.030	0.069
Sterling	0.3	12	1.4	47	0.002	0.003
Mitchell	0.2	24	0.8	97	0.004	0.011
Schleicher	0.1	14	0.6	57	0.003	0.001
Scurry	1.9	138	7.6	551	0.044	0.109

Table 4-4: Local and intermediate gathering distances and volumes

Wellhead oil follows a two-phase flow of production to a local separator (where oil, water and gas are separated) and then to a local gathering node, delivery point, or well pad. The initial two-phase flow from the well site to the separator is not expected to consume power, as well pumps accounted for in the upstream assessment provide this power. Power requirements for water transport beyond the separator are also accounted for in the upstream assessment.

For oil gathering and transport, an oil flow model was built to arrive at a matrix cube of power requirements for various diameters, volumes, and distances. The distances ranged from 0.1 miles to 100 miles, flows ranged from 10 bbl/d to 1,000,000 bbl/d, and pipe diameters included 3 inches, 8 inches and 20 inches. The elevation differential was 50 feet upward for the 0.1-mile estimate, with the elevation doubling for every factor of 10 in distance. So that the 100- mile elevation assumption was 400 feet upward. Average pump efficiency was set to 55%.

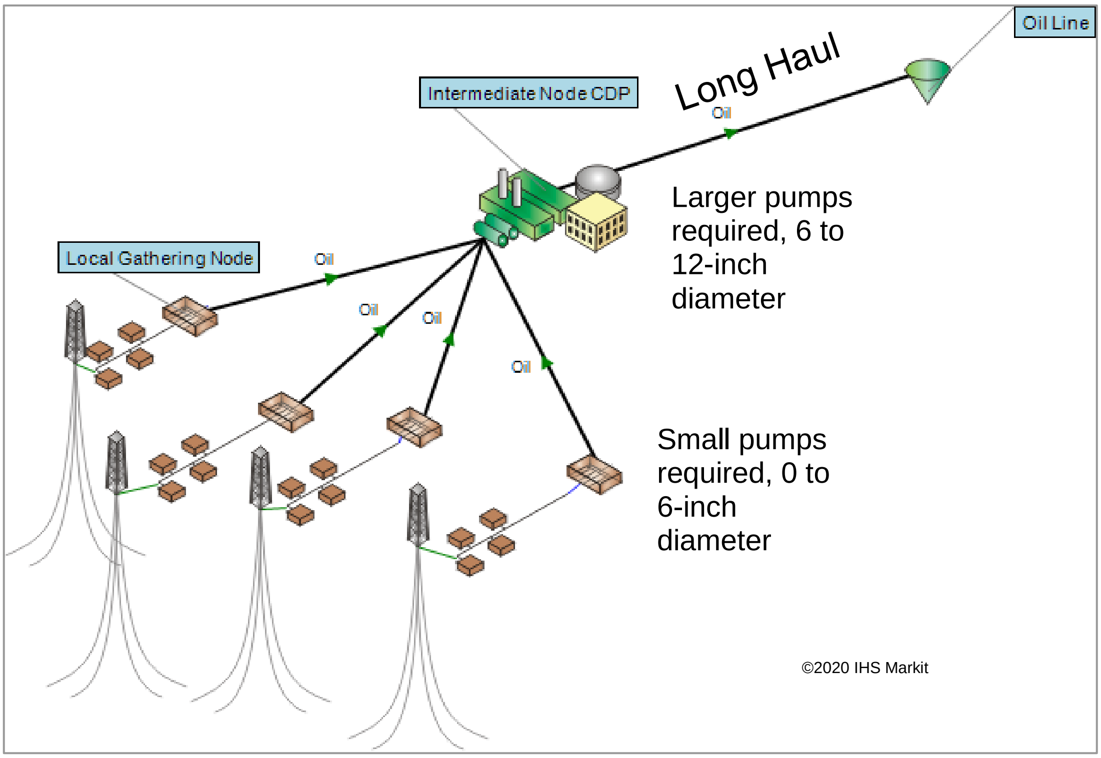


Figure 4-7: IHS QUE$TOR model for oil transportation

For each month, historically and in the forecast, linear interpolation was used to solve each matrix for a given set of distances and volumes.

3 Inch Diameter kW	0.1 Miles	1 mile	10 miles	100 miles
10 bbld	0.00564	0.00894	0.0156	0.029
100 bbld	0.0565	0.0904	0.167	0.403
1,000 bbld	0.582	1.07	3.27	20.3
10,000 bbld	15	103	954	9410
8 Inch Diameter kW	**0.1 Miles**	**1 mile**	**10 miles**	**100 miles**
10 bbld	0.00564	0.00894	0.0155	0.0287
100 bbld	0.0564	0.0894	0.155	0.289
1,000 bbld	0.564	0.894	1.58	3.12
10,000 bbld	5.73	11.5	25.2	126
100,000 bbld	114	669	5950	58300
20 Inch Diameter kW	**0.1 Miles**	**1 mile**	**10 miles**	**100 miles**
10 bbld	0.00564	0.00894	0.0155	0.0287
100 bbld	0.0564	0.0894	0.155	0.287
1000 bbld	0.564	0.894	1.55	2.87
10000 bbld	5.64	8.94	15.7	30.1
100000 bbld	57.3	64.7	237	1120
1000000 bbld	573	975	2380	11200

Table 4-5: Power consumption estimates by oil pipeline length, diameter and throughput rate

Then once each matrix is determined, linear interpolation is again used between the matrices given the pipeline diameter. As an example, Figure 4.6 below shows the interpolation result for local oil gathering system comprised of 9.7 wells with a daily oil throughput of 67 bbl/d. The pipeline distance is 0.3 miles for those 9.7 wells, while the average pipeline diameter for the county is 5 inches.

The interpolation result was 0.052 kW or 0.0057 KW per well, given 9.7 wells per pipeline. The prorated 0.0057 kW per well would then be used to assess power demand for the entire county's local oil gathering system, given the total number of producing wells in the county for the month.

Power Needed to Move Oil (KW) – 3-in Pipeline

Flow (Bbld)	0.1 Miles	1 mile	10 miles	100 miles
10	0.00564	0.00894	0.0156	0.029
100	0.0565	0.0904	0.167	0.403
1,000	0.582	1.07	3.27	20.3
10,000	15	103	954	9410

Power Needed to Move Oil (KW) – 8-in Pipeline

Flow (Bbld)	0.1 Miles	1 mile	10 miles	100 miles
10	0.00564	0.00894	0.0155	0.0287
100	0.0564	0.0894	0.155	0.289
1,000	0.564	0.894	1.58	3.12
10,000	5.73	11.5	25.2	126
100,000	114	669	5950	58300

Table 4-6: Example of linear interpolation for a local oil gathering system

Long-haul oil power assessment relies on the OPGEE (Stanford's Oil Production Greenhouse Gas Emissions Estimator) model. The model is publicly accessible and relies on public sources of data. It is widely cited in academic journals, including *Environmental Science & Technology* and *Nature Climate Change*, as well as by the Carnegie Endowment's Oil-Climate Index.

OPGEE model output for 30 API oil, using primarily reciprocating engines, suggests that 1 MMBTU of oil transported for one mile in a long-haul system will result in 7.5 BTU (of natural gas) being used as fuel. In other words, it will take 0.075% of the energy in oil to move the oil 100 miles (750 BTU per 1 MMBTU of oil). Lower APIs would require more energy due to differences in viscosity. Other sources generally corroborate these energy consumption figures, such as the Argonne National Laboratory's Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model (GREET).

To incorporate the OPGEE figures, IHS Markit worked out a formula to convert a barrel of oil to MMBTU, and then MMBTU to energy kWh. Oil moves approximately 8 miles per hour, or about 192 miles per day. At 0.075% of the oil energy used per 100 miles; that means that 0.00075% of the energy of a bbl is used per mile. Given 192 miles per barrel per day, one barrel per day uses 0.1443% of the energy of a barrel, or 0.000071 MMBTU per barrel per day.

Provided that gas-fired power plant efficiency ranges from 40% to 65%, with most in the lower end of the range, a 50% power plant efficiency was applied. Multiplication of kWh per MMBTU, MMBTU per mile, and efficiency of power generation gives 0.010362 kWh per mile per bbl/d. Conversion to kW from kWh by dividing by 24, indicates that long-haul oil uses about 0.000432 kW per bbl/d throughput on average.

Value	Label	Calculation explanation
1	bbl	Barrel of oil
5.88	MMBTU per bbl	1 bbl of oil has 5.88 MMBTU of energy
293.1	kWh per MMBTU	Relationship between kWh and MMBTU
8	Miles per hour oil velocity in pipe	Oil movement speed from literature (can be as low as 5 mph)
192	Miles per Day	Conversion from miles per hour to miles per day
0.075%	Energy Used per 100 miles	Value generated from research (OPGEE)
0.00075%	Energy % of bbl Used per mile per bbl	Conversion from 100 miles to 1 mile
0.1443%	Energy % of bbl Used per bbl/d	Accounting for 192 miles traveled per day
0.000071	MMBTU Use per mile per bbl/d	Calculation given share of energy used per barrel per day, and the energy in a bbl (in MMBTU)
50%	Efficiency of Power Generation	Expected power plant efficiency (ranges from 40% to 65%)
0.010362	kWH per mile per bbl/d	Multiplication of kWH per MMBTU, MMBTU per mile, and efficiency of power generation
0.000432	kW per mile per bbl/d	Conversion from kWh to kW by dividing by 24

Table 4-7: Energy to power conversion

Currently, there are over 5,100 miles of long-haul oil pipelines in the top 24 counties in the study. In order to determine the distance traveled per bbl, IHS Markit considered the total length of long-haul oil pipelines in each county, then compared it to the number of pipelines that cross the county to generate an average. In some counties, pipelines do not cross the same extent of the county as in other counties. Thus, in some instances the total number of pipelines may not be a whole number. The distances of long-haul pipelines are expected to remain fixed for duration of the study period (until 2030). The power estimates for long haul are greater than those of gathering lines per volume since the speed of flow and friction in gathering systems can be much less. Additionally, the total estimates of power will be greater due to cross-county volumes adding to the flow.

County	Total Long-Haul Distance (miles)	Major Lines (over 12 inches)	Length per Line (miles)	Current Long Haul Oil Power (MW)
Loving	336	5	67	13.0
Winkler	278	7	40	6.6
Ward	226	8	28	4.2
Reeves	364	6	61	19.7
Culberson	72	1.5	48	1.7
Midland	565	12	47	17.7
Howard	269	7	38	12.3
Martin	188	7	27	5.6
Glasscock	254	6	42	18.1
Upton	229	7	33	7.3
Reagan	137	6	23	3.3
Pecos	147	5	29	10.8
Crane	283	7	40	7.1
Ector	199	7	28	2.5
Andrews	209	9	23	1.7
Gaines	136	4	34	2.1
Dawson	0	0	0	0.0
Borden	0	0	0	0.0
Crockett	264	2	132	69.4
Irion	53	2	27	5.2
Sterling	80	3	27	13.2
Mitchell	346	8	43	13.9
Schleicher	72	2	36	9.9
Scurry	415	3	138	93.4

Table 4-8: Long-haul pipeline network by county

The resulting total power estimate for each month in the model is the product of the power per bbl/d per mile, the average daily volumes in the county for that month, and the average miles a barrel travels in that county.

2.4.4 Assessing County Power Requirements for NGL Pipelines

NGL volumes extracted in the Permian Basin are roughly 25% to 35% of the total oil production volumes. Moving NGLs by pipeline generally occurs after processing so we have not included these in gathering as all of our models apply gathering to wet gas volumes which are pre gas processing. Because NGLs are lighter (higher API) and less viscous than oil, our QUE$TOR models indicate that it takes approximately half the energy per volume as oil.

By applying this 50% of power usage, compared to oil, to the 25% to 35% percentage of NGL volumes, we have determined that the power requirements for NGL long haul transport would be, about 12.5 to 17.5% of the oil power requirement. Furthermore, we have to take into consideration a number of issues associated with a possibly higher portion of NGLs pertaining to ethane which may include ethane rejection, and lower volumes of Y-grade transport. In order to account for power attributable to long-haul NGL volumes we determined that NGL power usage would be about 10% of the oil volume power requirements. Hence, the power requirements, both current and forecasted, which apply to the oil forecast have been grossed up by 10% to reflect the contributions of NGL long haul transport.

2.4.5 Assessing County Power Requirements for Gas Pipelines

In order to determine the amount of power consumed by a gas pipeline compressor, IHS Markit first estimated the flow rate, and distance and diameter, to ultimately arrive at the pump pressure differential. IHS QUE$TOR, the industry standard for Pre-FEED (front-end engineering) studies, was utilized for calculation of the pump pressure differentials. Elevation differentials are standardized per distance traveled. The power demand is re-assessed monthly, based on historical and forecasted average daily volumes, historical and future total pipeline length, and length-weighted average pipeline diameter for each county. Local and intermediate gathering systems are split into diameter categories, each average diameter reflects its respective category. Local gathering average diameters range from 3 to 5 inches, and intermediate gathering diameters average around 8 inches.

County	Local Gathering Line Distance (miles)	Volume Per Local Gathering Line (Mcf/d)	Intermediate Gathering Distance (miles)	Volume Per Intermediate Gathering Line (Mcf/d)	Current Total Gas Gathering Power (MW)
Loving	0.8	2,477	6	9,906	95.4
Winkler	1.9	628	13	2,513	10.3
Ward	1.2	941	11	3,762	28.4
Reeves	0.6	3,011	5	12,045	209.3
Culberson	0.9	5,251	7	21,003	72.8
Midland	1.1	1,278	6	5,113	94.9
Howard	0.7	603	8	2,411	25.9
Martin	1.6	729	7	2,918	40.0
Glasscock	0.8	887	8	3,546	34.1
Upton	1.0	874	9	3,496	45.9
Reagan	1.3	985	8	3,941	50.4
Pecos	3.5	794	16	3,175	21.9
Crane	1.3	263	7	1,052	8.3
Ector	1.1	193	6	771	10.4
Andrews	1.0	196	4	786	14.5

Gaines	1.0	153	4	613	5.1
Dawson	1.9	28	6	112	0.5
Borden	2.5	250	9	1,002	1.4
Crockett	6.5	873	14	3,491	19.4
Irion	2.4	1,141	8	4,564	28.3
Sterling	3.8	146	11	584	1.6
Mitchell	0.2	7	3	27	0.9
Schleicher	11.7	363	35	1,451	1.5
Scurry	2	394	28	1,578	7.4

Table 4-9: Local and intermediate gathering distances and volumes

The gas production from the wells follows the same multi-phase flow of production along with oil to a local separator, and then to a local gathering node, delivery point, or well pad. The initial multi-phase flow from the well site is not expected to use any power as flowing pressures are sufficient or the fluid is being propelled by a pump at the well head.

A gas flow model was built to arrive at a matrix cube of power requirement for various diameters, volumes, and distances. The distances ranged from 0.1 miles to 100 miles, flows ranged from 100 Mcf/d to 100,000 Mcf/d, and pipe diameters included 3 inches, 8 inches and 20 inches. The elevation differential was 50 feet upward for the 0.1-mile estimate, with the elevation doubling for every factor of 10 in distance. So that the 100-mile elevation assumption was 400 feet upward. Average pump efficiency was set to 55%.

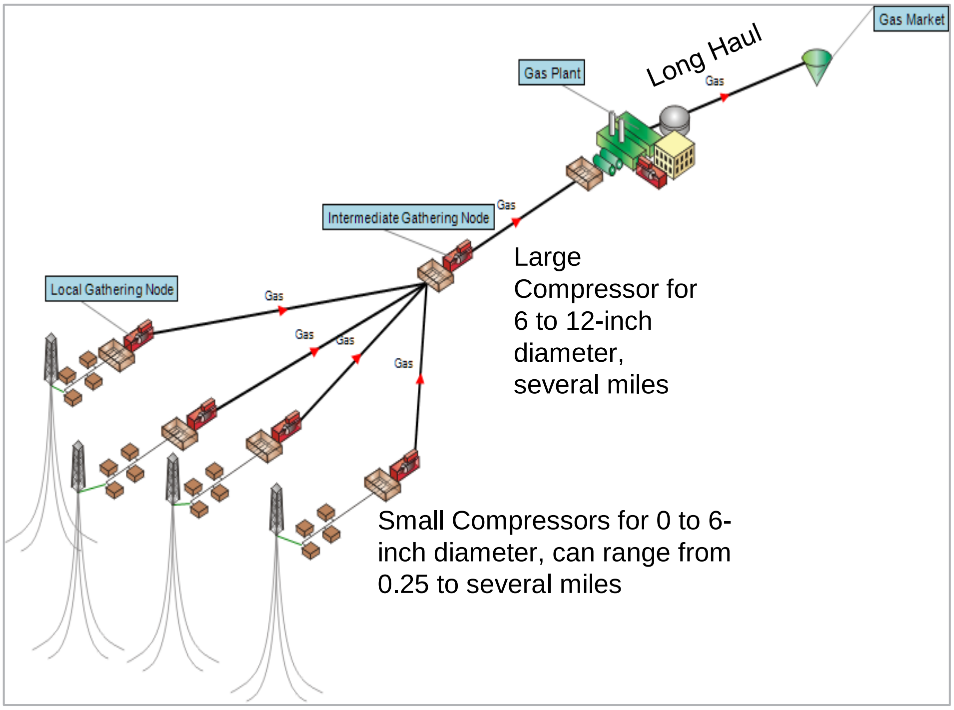


Figure 4-9: IHS QUE$TOR model for gas transportation

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3 Inch Diameter kW	0.1 Miles	1 mile	10 miles	100 miles
100 mcfd	0.2111	0.2111	0.318	0.557
1,000 mcfd	0.655	1.48	6.53	31.6
10,000 mcfd	49.1	352	767	1380
100,000 bbld	10300	40600	56700	174000
8 Inch Diameter kW	**0.1 Miles**	**1 mile**	**10 miles**	**100 miles**
100 mcfd	7.36	7.36	7.42	7.48
1,000 mcfd	58.9	58.9	59.4	60
10,000 mcfd	552	552	563	598
100,000 mcfd	4360	4640	6150	10600
20 Inch Diameter kW	**0.1 Miles**	**1 mile**	**10 miles**	**100 miles**
100 mcfd	7.36	7.36	7.42	7.48
1,000 mcfd	58.9	58.9	59.4	60
10,000 mcfd	552	552	557	563
100,000 mcfd	4,320	4,320	4,400	4,710

Table 4-10: Power consumption estimates by gas pipeline length, diameter and throughput rate

For each month historically and in the forecast, linear interpolation was used to solve each resulting data matrix for a given set of distances and volumes. Then, once the value of each matrix was determined, linear interpolation was again used between the matrices given the pipeline diameter

As an example, Table 4-11 below shows the interpolation result for local gathering system comprised of 27.2 wells with a daily gas throughput of 2,665 Mcf/d. The pipeline distance is 8.7 miles for those 27.2 wells, while the average pipeline diameter for the county is 8.4 inches.

Power Needed to Move Gas (kW) – 8-in Pipeline

8 Inch Diameter kW	0.1 Miles	1 mile	10 miles	100 miles
100 mcfd	7.36	7.36	7.42	7.48
1,000 mcfd	58.9	58.9	59.4	60
10,000 mcfd	552	552	563	598
100,000 mcfd	4360	4640	6150	10600

Power Needed to Move Gas (kW) – 20-in Pipeline

20 Inch Diameter kW	0.1 Miles	1 mile	10 miles	100 miles
100 mcfd	7.36	7.36	7.42	7.48
1,000 mcfd	58.9	58.9	59.4	60
10,000 mcfd	552	552	557	563
100,000 mcfd	4,320	4,320	4,400	4,710

Table 4-11: Example of linear interpolation for a local gas gathering system

The interpolation result was 152.2 kW or 5.6 kW per well, given 9.7 wells per pipeline. The prorated 5.6 kW per well would then be used to assess power demand for the entire county's intermediate gas gathering system, given the total number of producing wells in the county for the month.

Long-haul of gas is expected to require significantly more power than long-haul of oil for the same amount of energy moving in the pipe due to the compressibility of gas. Many components can impact the power requirement for long-haul transportation, including maximum allowable operating pressures, age, efficiency ratings, and ratios of flow to pipeline volume. Analysis shows that increasing pipeline volumes can hyperbolically increase the energy required to move the gas in the pipe. Adding to this are the sequence or compressors, elevations changes over long distances, and lack of pressure differentials, such as that seen in gathering systems.

With a view to the wide variation in the power required, IHS Markit experts, with experience in long-haul gas transportation construction, determined that the energy requirement ranged from 0.1% to 0.5% of the energy in a pipeline over 100 miles distance. With newer and more efficient pipelines operating at higher MAOPs in the Permian, IHS experts expect that the energy required will be at least at the midpoint, or perhaps even lower. Thus, applying 0.25% of the gas energy per 100 miles for long-haul pipeline travel is a reasonable approximation.

The Energy Information Administration (EIA) data supports the purported range of 0.1% to 0.5% as "pipeline and distribution use" accounts for 2.5% of natural gas production in the United States. According to the EIA, from 2015 to 2018, it took 2.95 trillion cubic feet of gas (Tcf) of energy equivalent to move a total of 119.2 Tcf. Applying a rate under 0.1% suggests that each molecule of gas travels at least 2,500 miles on average (2,500 miles X 0.1% per 100 miles = 2.5%), which is very unlikely. In IHS Markit expertise, pipeline losses are known to be just 5.2% in the Permian. That amount of pipeline shrink is not enough to support a more appropriate distance at 0.1%. Similarly, applying a rate of 0.5% suggests that each molecule of gas travels under 500 miles, which is the distance from the Permian Basin to Houston - but it can't account for gathering and distribution, making the figure too high.

The EIA data suggests that the range defined by the IHS experts is reasonable and the extremes of the ranges are not the correct assumptions; thus, the midpoint of the range is taken to estimate long-haul gas transportation. This means that 0.25% of the natural gas volumes must be burned at a power plant, or other power generation site, to create the power for moving gas in long-haul pipelines. Thus, in order to transport 1 MMBTU of natural gas (1 MMBTU is equivalent to 1 Mcf), 0.25 BTU/1 BTU (of natural gas) must be burned.

In order to use the EIA supported figures, IHS Markit worked out a formula for converting an Mcf of gas to MMBTU, then MMBTU to energy kWh. Gas moves approximately 35 miles per hour, or about 840 miles per day. At 0.25% of the oil energy used per 100 miles, that means that 0.0025% of the energy of an Mcf is used per mile. Given 840 miles per Mcf per day, 1 Mcf/d uses 2.1% of the energy of an Mcf, or 0.000175 MMBTU per Mcf/d.

Provided that gas-fired power plant efficiency ranges from 40% to 65%, with most in the lower end of the range, a 50% power plant efficiency was applied. Multiplication of kWh per MMBTU, MMBTU per mile, and efficiency of power generation gives 0.025644 kWh or per mile per Mcf/d. Conversion to kW from kWh by dividing by 24 indicates that long-haul gas uses about 0.001068 kW per Mcf/d throughput on average.

Value	Label	Calculation explanation
1.0	Mcf	
1.0	MMBTU	1 Mcf of gas has 1.0 MMBTU of energy
293.1	kWh per MMBTU	Relationship between kWh and MMBTU

35	Miles per hour	Gas movement speed from literature (high of 40mph)
840	Miles per Day	Conversion from miles per hour to miles per day
0.25%	Energy per 100 miles per Mcf	Value generated from research
0.0025%	Energy used per mile per Mcf	Conversion from 100 miles to 1 mile
2.1000%	Energy Used per mile per Mcf/d	Accounting for 840 miles traveled per day
0.000175	MMBTU Use per mile per Mcf/d	Calculation given share of energy used per Mcf per day (an MMBTU)
50%	Efficiency of Power Generation	Expected power plant efficiency (ranges from 40% to 65%)
0.025644	kWh per mile per Mcf/d	Multiplication of kWh per MMBTU, MMBTU per mile, and efficiency of power generation
0.001068	kW per mile per Mcf/d	Conversion from kWh to kW by dividing by 24

Table 4-12: Energy to power conversion

Currently, there are over 14,000 miles of long-haul gas pipelines, which is nearly three times the amount of oil pipelines in the 24 counties in the Far West weather zone. In order to determine the distance traveled per Mcf in each county, IHS Markit considered the total length of long-haul gas pipelines in each respective county, then compared it to the number of pipelines that cross that county to generate an average distance. In some counties, pipelines do not cross the same extent of a county area as in the other counties. Thus, in some instances the total pipelines number may not be a whole number. The distances of long-haul lines are expected to remain fixed for the duration of the study period (until 2030).

County	Total Long-Haul Distance (miles)	Major Lines (over 12 inches)	Length per Line (miles)
Loving	761	5	38
Winkler	530	7	44
Ward	796	8	57
Reeves	2,068	6	65
Culberson	769	1.5	48
Midland	1,094	12	46
Howard	365	7	30
Martin	759	7	42
Glasscock	655	6	41
Upton	854	7	36
Reagan	756	6	38
Pecos	1,293	5	46
Crane	416	7	28
Ector	618	7	41
Andrews	649	9	54

Gaines	244	4	35
Dawson	70	3	35
Borden	45	3	22
Crockett	556	2	31
Irion	238	2	30
Sterling	212	3	35
Mitchell	95	8	32
Schleicher	132	2	16
Scurry	114	3	57

Table 4-13: Long-haul pipeline network by county

As seen in several Texas locations, it is possible for a large gas compressor stations to rely on grid energy for primary operations; however, it is unlikely considering the available source of energy that is held within the pipeline. IHS Markit does not model any power demand for long-haul gas.

2.4.6 Assessing County Power Requirements for Gas Processing Plants

In the Permian Basin, there is currently over 17 Bcf/d of wet gas processing capacity. Over 25% of the total capacity resides in Reeves County, but gas processing plants are dispersed across the region for treatment of localized production. In recent years, Permian gas processing plants have expanded with over 6 Bcf of capacity coming online since 2017 to process associated gas from oil wells in the area. Limitations in gas plant capacity can hinder the development and production of oil wells, and as such, gas processing capacity is critical to oil and gas economics in the Permian Basin.

County	Number of Plants Operating	Current Capacity (MMcf/d)	Capacity Under Construction (MMcf/d)	Planned Capacity (MMcf/d)
Andrews	3	210		100
Borden	1	50		
Crane	3	275		
Crockett	7	327		
Culberson	4	510	310	850
Ector	3	385		
Gaines	4	315		
Glasscock	4	793	200	
Howard	1	50		
Irion	3	108		
Loving	5	1,390	500	400
Martin	7	730		
Midland	12	1,605		
Pecos	11	1,974		
Reagan	2	412		
Reeves	14	4,031		

Schleicher	1	Unreported		
Scurry	1	90		
Sterling	3	172		
Upton	9	1,265		
Ward	9	1,935		
Winkler	3	485		

Table 4-14: Gas processing plant capacity by county

Gas processing plants are a major power user and often rely on grid power, but certain processes, such as gas compression, are most often left to self-provided energy from gas turbines. In order to estimate plant power requirement, IHS Markit relied on a combination of its field development software, IHS QUE$TOR, and the information provided by Oncor.

The results from IHS QUE$TOR were used to develop a non-coincident power scale based on the inlet wet gas capacity of each plant. A coincidence factor of 93% has been applied according to Oncor provided data.

Throughput (MMcf/d)	Normalized QUE$TOR Total Power (kW)	Normalized QUE$TOR Coincident Peak kW (93%)
50	3,465	**3,222**
100	6,938	**6,452**
200	11,992	**11,153**
400	21,859	**20,329**
600	31,363	**29,168**
800	45,100	**41,943**

Table 4-15: Gas processing plant capacity by county

Not all gas processing plants rely on grid power. Industry expectations are that smaller gas processing plants are more likely to rely on grid power than larger ones due to the massive amount of energy required. However, the remoteness of the Permian Basin and the abundance of natural gas has allowed some gas processing plants to be developed without grid power.

IHS Markit performed a mapping exercise with Oncor and observed that some plants do not have access to the grid. In general, we found that recent plants that came online in the past two years have a higher likelihood of being on the grid.

Further power grid expansion is not expected to influence a gas processing plant's reliance on grid power. Once a gas processing plant is set to self-generate power, it will remain that way. If power infrastructure is available, any newly built gas processing plants are expected to connect to the grid.

2.4.7 Assessing County Power Requirements for Refineries

There is only a single operating refinery in the region. Several have been decommissioned in the past few years with production from older conventional Permian fields shutting down. Most production is expected to continue to be sent to the Gulf Coast for refining, but at least one refinery by MMEX is expected to be online in Pecos County with an expected capacity of 90,000 bbl/d in 2022.

Due to the limited number of current and forecasted refineries in the region, they account for a small component of the total Permian power demand. However, each refinery requires a significant power load to operate, which can greatly influence the power demand in a county. The only operating refinery in the Permian Basin is the 67,000 bbl/d Alon facility in Howard County.

From the EIA and other research, a range from 30 kW to nearly 50 kW per 100 bbl/d of capacity was identified. IHS Markit applied 42 kW per 100 bbl/d of refining capacity when estimating average refinery power.

2.4.8 Assessing County Power Requirements for other Industrial items

During the process of reviewing both the monthly billing data provided by Oncor, several other oil and gas operations were identified that also appear to be using electrical grid power. These include some operations related to CO2 EOR and sand mines. The usage of these is included with the Refinery classification. Additionally, in Dawson and Crane counties, Oncor identified several billing MW of power usage in the industrial sector that could not be attributed to known oil and gas activity. Those loads have also been included in the Refinery classification.

3 Permian Basin Historical and Forecasted Industrial Power Demand

3.1 Introduction:

In the previous section, relationships between specific oil and gas activities and power requirements were documented and established. Upstream operations include artificial lift at the wellhead--which enables the lifting of oil and water from the wellbore to the surface, as well as water disposal. Midstream operations require power for oil and gas gathering and compression, as well as long-haul oil transport and the operation of gas processing plants. Part 3 will build on this analysis by comparing, within each of the 24 counties, historical power usage to the actual power demand of oil and gas related activities in order to: (1) validate the calculated power usage against real historical data, (2) determine to what extent oil and gas operations are on the electrical grid within each of the counties, (3) build a power demand forecast at the county level by applying these comparisons, (4) apply appropriate load factors to calculate peak coincidence, and (5) integrate these county-level power forecast with current and projected oil and gas activities, including projected drilling to identify areas where the highest likelihood of increased demand is likely to occur.

Findings:

- Growth became stronger in 2018. Industrial power usage grew strongly, from less than 2,000 MW in early 2016 to approximately 3,400 MW by the end of 2019. Over the four-year period, Oncor has provided service for over 70% of total power usage. By the end of 2019, Oncor provided almost 2,500 MW of the 3,400 MW total estimated average industrial power usage within the 24 counties.

- Given that the Central Basin Platform has an on-grid percentage of 96%, we would consider this to be the extent of the grid potential in that region. The Midland Basin grid connection has been growing rapidly but is approaching total grid connection in several counties. The Delaware Basin still has considerable grid connection growth potential ahead of it. Note that these calculations reflect contributions of all the 24 counties, including those not served by Oncor where we have estimated power demand.

- In the Delaware Basin, the current average oil/gas activity demand is 1,664 MW, and the serviced demand peak is just under 1,200 MW. Supplied demand peak power is expected to nearly quadruple over the next 10 years. By 2030 peak oil/gas load is expected to be near 4,700 MW with industrial coverage expanding from 61% to 97% over the forecast period.

- In the Midland Basin, the current average oil/gas activity demand is 1,322 MW, and the serviced demand peak is just over 1,500 MW. Peak industrial load is expected to more than double over the next 10 years, but demand will wane towards the end of the decade. By 2030, demand peak industrial load is expected to be near 2,500 MW, with industrial coverage expanding slightly from 96% to 97% over the forecast period.

- In the Central Basin Platform, the current average monthly billing is 695 MW, which is about 90% of the current oil and gas activity. The oil and gas activity is expected to decrease in the near future, which will align with the monthly billing. The demand peak is just under 750 MW and will decrease slightly in conjunction with the projected decrease in monthly power billing. With little change in oil and gas activity forecasted, and most industrial loads supported by the grid already, peak industrial demand supplied by the grid will remain relatively flat in the Central Basin Platform for the next 10 years.

- In the Fringe region, the current average oil/gas activity demand is 438 MW, and the serviced peak is just over 500 MW. Peak industrial power supplied is expected to only increase slightly over the forecast period. By 2030 peak demand is expected to be around 600 MW.

- The current grid system will need to catch up to ongoing activities primarily in the Delaware Basin as the power markets of some of the Delaware Basin counties are the least served. Growth in the Delaware Basin area electrical infrastructure needs to outpace growth in the projected oil and gas activity power demand over the next several years, and our forecast indicates that at current rates of grid expansion, complete grid access for projected oil and gas activity demand will not occur until late 2024.

- The grid infrastructure in the Midland and Fringe area counties has already met most of the current demand. Expansion in these areas will be limited to the growth in industrial activities. The Central Basin Platform already has adequate grid coverage given the current oil and gas activities. There may still be a need for grid expansion in some counties, as oil and gas operators develop new sources of oil and gas, but this is expected to be limited in the future.

- From 2020 to 2030, the largest power increases are expected to be in the Delaware Basin. Larger changes in the Midland Basin are expected in Howard County with some meaningful increases also expected in Upton and Reagan Counties. The east Ector and Andrews county issue discussed earlier will also show up here as well. Between 2020 and 2030, power demand is expected to increase by 3,260 MW (upstream, gathering and oil transport).

3.2 Reconciliation of Public and Oncor Supplied Electric Load Data

3.2.1 Introduction and Purpose

In order to effectively compare and benchmark oil and gas activities with historical power usage, we required a consistent and reliable source of historical industrial power for each county. Data supplied by Oncor included: Residential, Commercial and Industrial county level consolidated Monthly billing data, 15-minute load data, and ALDR data. Since oil and gas activities are recorded at the monthly level, we selected the monthly billing data to make comparisons; furthermore, we determined that this dataset is the most detailed and complete of the Oncor provided data sets. The goals of these comparisons were to (1) establish a consistent monthly baseline of industrial power demand by county and region from January 2016 to late 2019 to compare with oil and gas operations, which could then be used throughout the remainder of the project; and (2) by comparing monthly billing data with the 15-minute data, we would be able to calculate load factors, which could then be applied to the monthly billing data to generate historical and forecasted coincident peak values.

In order to effectively establish this baseline industrial power demand, we performed three additional steps: (1) estimating monthly power usage within several counties before the 2018 Sharyland acquisition; (2) for counties where Oncor was only a partial transmission distribution service provider (TDSP), calculating total historical power usage by grossing-up the Oncor monthly billing data by factors which Oncor provided; and (3) estimating the historical power usage in counties where Oncor does not provide service and where we received no billing data, by evaluating the historical oil and gas activity, and then applying a percentage of grid connection to that activity, based on observations in adjacent counties where we had Oncor data. Each of these steps was important so that we could account for historical power demand and project a complete picture of future power demand in all 24 counties included in this study.

We were also able to demonstrate using the 15-minute data how peak coincidence has evolved by county and region from January 2018 to late 2019. The 15-minute peak was combined with the monthly billing data to create a load factor in each county and region.

3.2.2 Detailed Methodology

Monthly Industrial Power Demand: To establish the baseline of industrial power demand, we used the data Oncor provided for each county which was made available in the aggregated monthly billing with a Combined Oncor/Sharyland dataset. (see the green solid line labeled "Historical Industrial Average Load - Oncor pre-Sharyland on Figure 2-1 below.)

In order to achieve a consistent historical view of data usage, we had to perform some additional calculations and estimations in order to provide a consistent picture of the entire county for each of the 24 counties in the study.

Step 1: When a county included territory from the November 2017 Sharyland acquisition, we developed an estimation for power demand for the portion of the county in the Sharyland acquisition prior to 2018. This step was necessary in order to analyze the county with a consistent basis; pre-2018 data that fails to account for Sharyland load presented values that were too low, because Oncor was not able to supply Sharyland data.

- We considered the extent to which values increased after the acquisition occurred. After this process, the data appeared more consistent and smoother, and had a greater degree of accuracy in the pre-2018 period.

- This estimate was combined with the existing data provided by Oncor to develop an estimation of the total industrial demand in Oncor's territory. (See the red segmented line labeled "Historical Industrial Average Load – Combined Oncor+Sharyland (pre 2018 estimated)" shown in Figure 2-1).

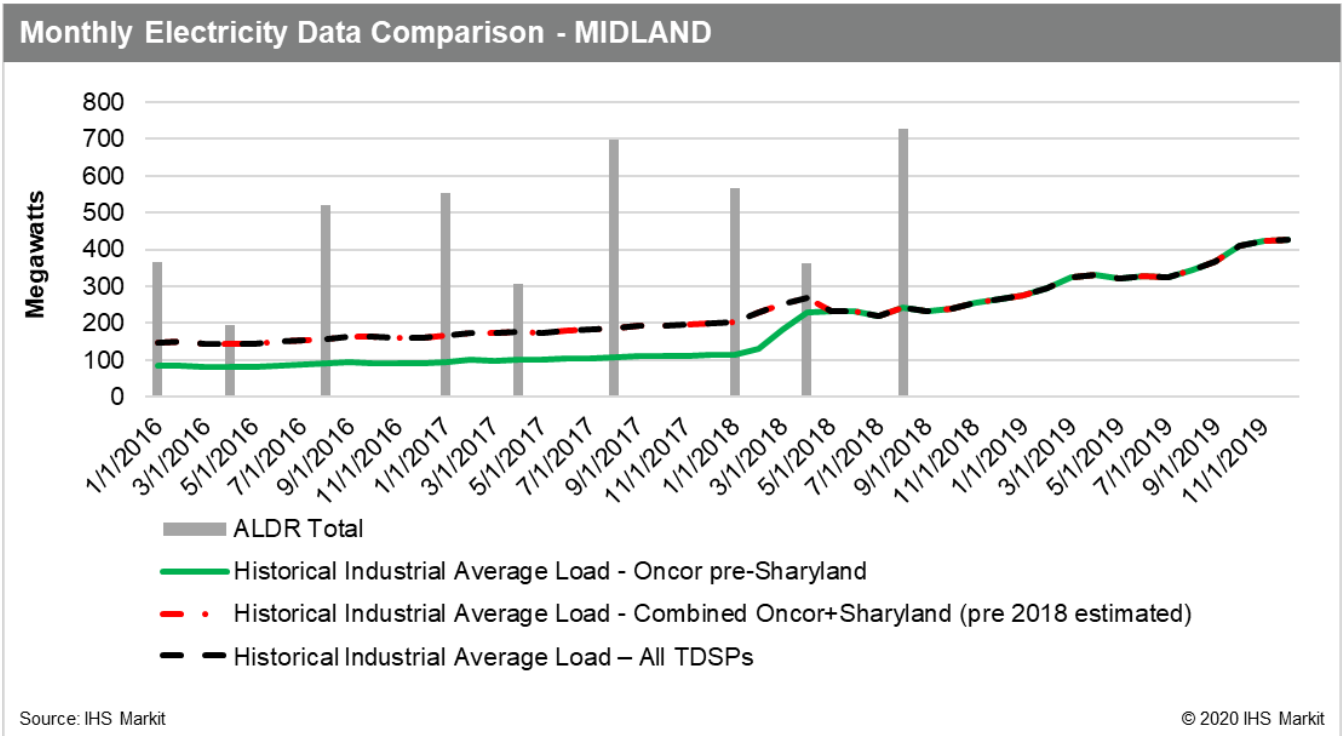


Figure 2-1: Comparison of monthly power data

Step 2: For counties not fully served by Oncor and also partially served by other TDSPs, we had to estimate the industrial power demand for this other TDSP in order to fully account for industrial demand in the county, whether or not Oncor was the primary TDSP.

- IHS Markit conducted its analysis largely based on the share of power on the Oncor system. Except for Pecos County, we maintained that although sometimes the power demand in a territory served by another TDSP grew at a different rate than the power supplied in Oncor's territory, we generally maintained a consistent growth rate depending on Oncor's county level load share.

- The other TDSPs load was added to the Oncor data in the red segmented line. (See the black segmented line labeled "Historical Industrial Average Load – All TDSPs." In Figure 2.2-1). Using these calculations, we were able to arrive at a line representing power usage values, which is used throughout the remainder of the report as the baseline industrial power demand by county or region).

- For counties where Oncor does not operate and for which we received no monthly billing data, we estimated the historical power demand in those counties, by first determining the total power usage for oil and gas activities in that county and applying grid connection factor for the end of 2019, based on that of an adjacent county and then back casting the data so as to achieve a historical trend (Figure 2-2).

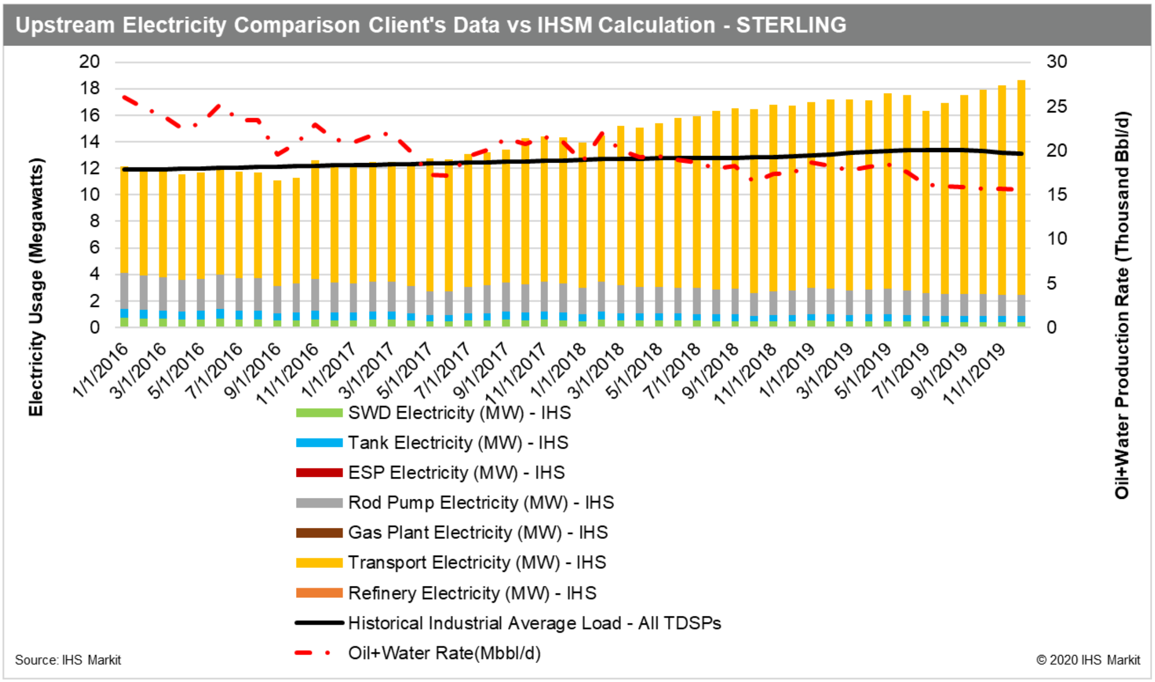


Figure 2-2: Example of power usage estimation for non-Oncor serviced county

Step 3: After the monthly billing data was estimated, there were many peaks and valleys that Oncor indicated were due to differences in billing cycles, including delayed billing and billing adjustments. We applied a 3-month moving average to the data in order to smooth out unexpected fluctuations, peaks, and valleys, which helped to apply a better comparison with the historical demand due to oil and gas activities (see next section).

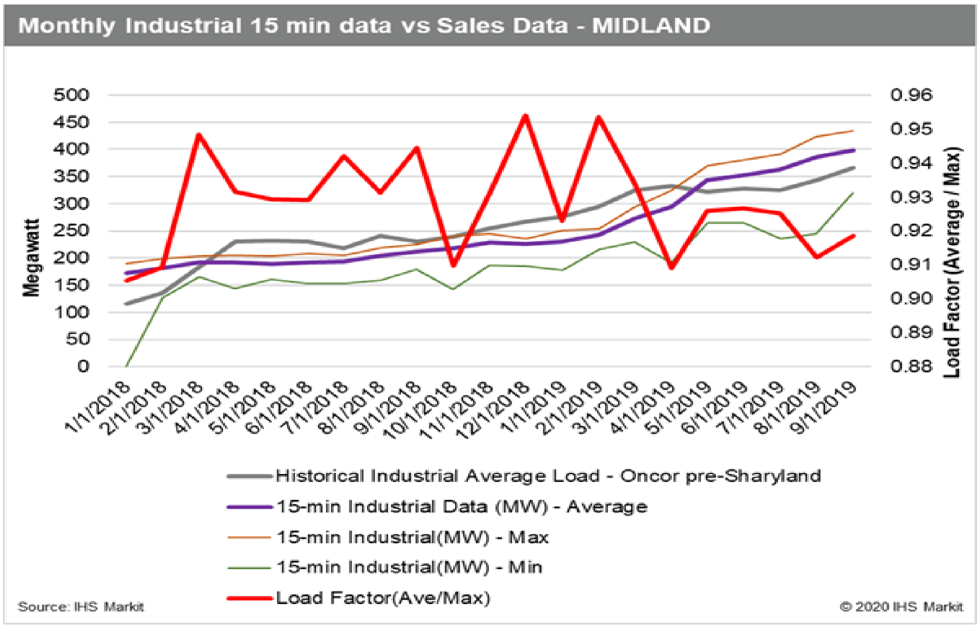


Figure 2.3: Midland County 15-Minute Interval Data

Calculating Load Factors to Peak Demand: Utilities account for peak load when planning

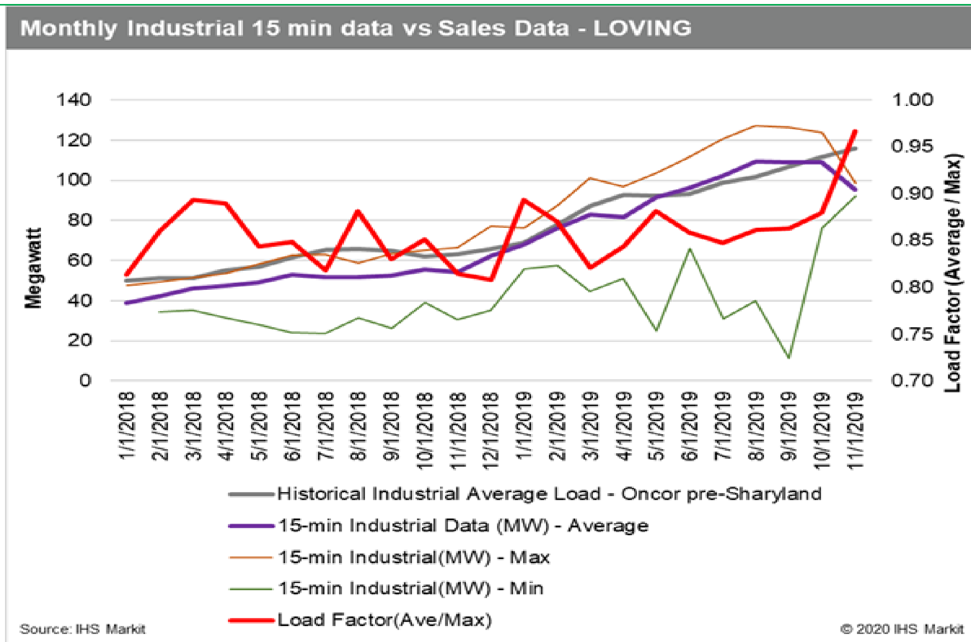


Figure 2.4: Loving and Midland County Basin 15-Minute Interval Data

capacity, and this analysis more directly focuses on this aspect. These calculations were performed for industrial power using 15-minute industrial data supplied by Oncor. We calculated monthly load factors by (1) determining the maximum peak value from the 15-minute data within a given month and the average of the 15-minute data for that month, and (2) then dividing the average by the maximum value obtained from the 15 minute data. Load factors were calculated for each month of the past two years so that we could establish a seasonality or other possible pattern to repeat for the forecast. The monthly load factors for the past two years were applied to the forecasted monthly data to generate a forecast of peak demand. The load factor of January of 2020 is equal to the average of January 2018 and January 2019. Such an approach helps to highlight the variability in load from month to month. This is illustrated in figures 2.3 and 2.4 where the monthly minimum is a light and thin green solid line, the maximum is a light and thin orange solid line, and the average is a dark and heavy purple line. Load factors were calculated by county and are shown in red. For counties where no 15 minute data were available, we used load factors of nearby counties within the same regional group.

3.3 Summary Results by Region

These comparisons were performed for all counties. Part 5 of this report is a discussion of each county and the graphical comparison of data streams (except for the 15-minute data) is provided for each county with each respective county write up. For purposes of summarizing results, set forth below is a summary of each of the four regions.

Grouping Results by County: The last step was aggregating data and analysis into four regions, as shown on the map below (see Figure 3-1). The purpose of this step was to (1) group mature and emerging petroleum provinces so that we could see how well comparisons of power usage to oil and gas power demand would compare in mature petroleum provinces where we assumed that most operations were on the power grid and (2) aggregate data from similar adjoining counties so that we could evaluate power use in similar oil and gas industry settings and estimate power usage in counties with limited or no Oncor billing data. As shown on the map, most of the recently drilled horizontal wells are either in the Delaware Basin region, or the Midland Basin region where we see the most activity and expect the most growth in power demand. Thus, this approach separates regions with fast growth from those with slower or no growth. We can then ascertain how much grid power is being provided to the fast-growing regions relative to the slower-growing regions.

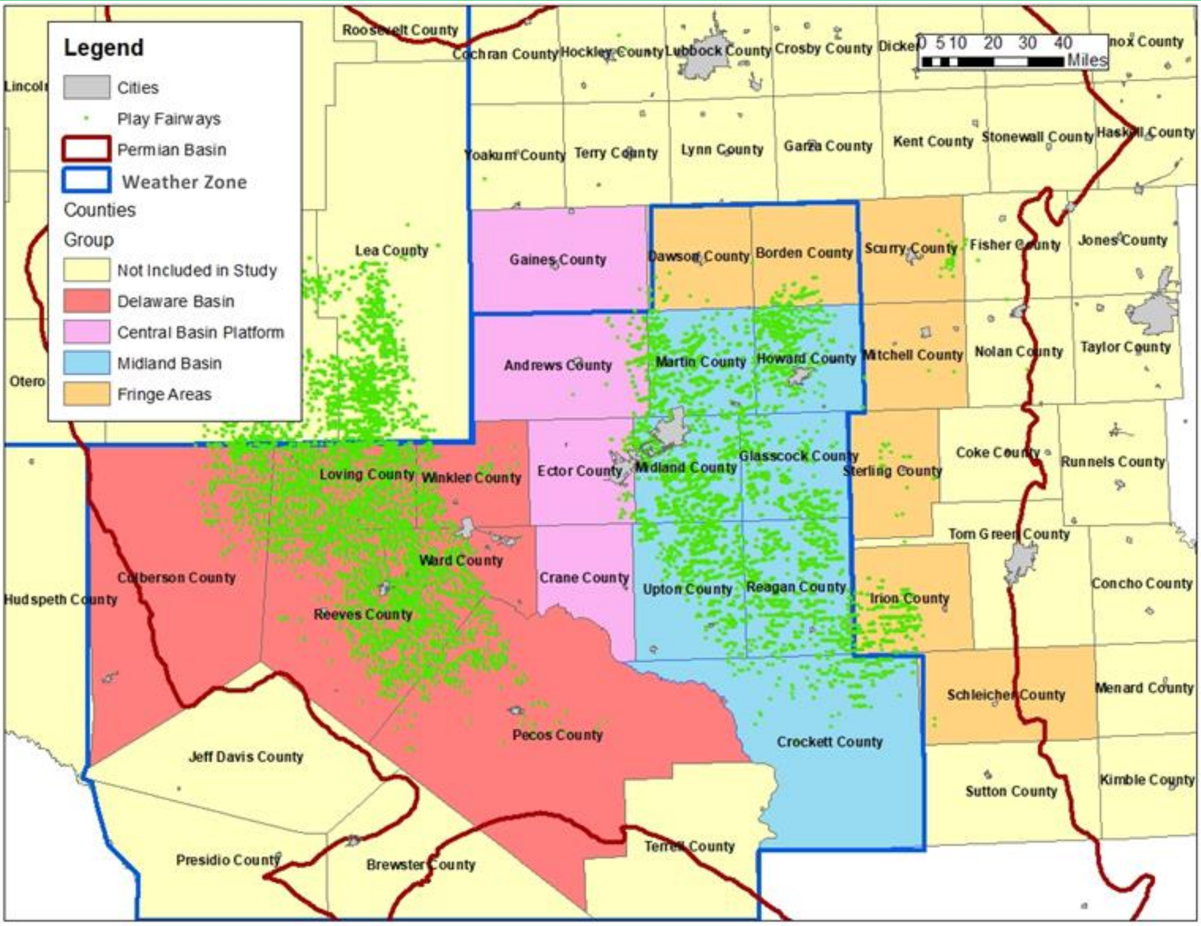


Figure 3-1: Map of Permian Basin by County

A description of each of the regions is set forth below, along with the counties included (see Figure 3-1):

- Central Basin Platform: This is a mature petroleum province with conventional production from vertical wells. Counties included in the data analysis are Andrews, Crane, and Ector and Gaines.

- Delaware Basin: This is an emerging petroleum province where power usage is increasing but has not caught up with demand from oil and gas activities. We expect both oil and gas activity demand and power usage to grow. Counties included in the data analysis are Culberson, Loving, Pecos, Reeves, Ward, and Winkler.

- Midland Basin: This is a maturing petroleum province where power usage has nearly caught up with demand from oil and gas activities. Growth here is likely to track the forecasted power demand from oil and gas activities. Counties included in the data analysis are Crockett, Glasscock, Howard, Martin, Midland, Reagan, and Upton.

- Fringe: This is a mature petroleum province with relatively minor contributions. Counties include Dawson, Borden, Scurry, Mitchell, Sterling, Irion and Schleicher. Note that several of these counties fall outside the Far West Weather Zone.

Aggregated Results: The graphs below represent the aggregated results for each region. All industrial power demand forecasts include all 24 counties whether Oncor supplied data or not in that county.

Central Basin Platform: This region shows stable power demand. Our estimates show that about two thirds of the industrial power demand are supplied by Oncor, so uplift estimates comprise a smaller portion of the total estimate. The load factor has stayed in a relatively narrow range (about 0.65 to about 0.70) (Fig. 3-2).

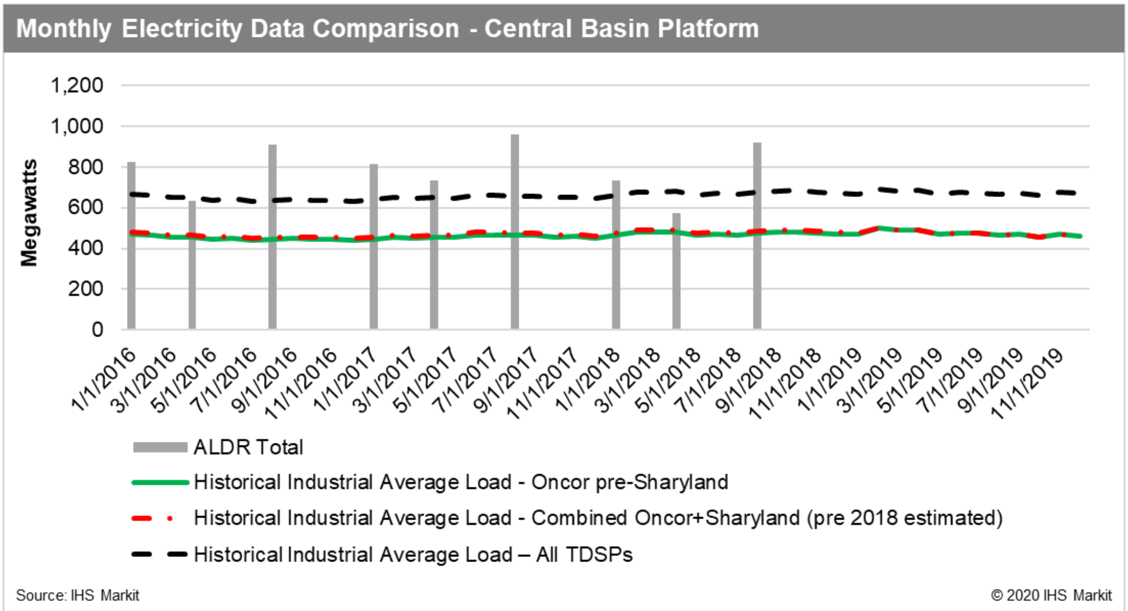


Figure 3-2: Monthly electricity data comparison for Central Basin Platform

Delaware Basin: This region shows rapidly rising power demand that is nearly entirely driven by industrial loads. Other TDSPs provide a substantial amount of power in the region. Power usage trends have been rising steadily for the past two years. Meanwhile, load factors have been steadily rising, from less than 0.50 to about 0.60. (Fig. 3-3). This indicates a need to expand electric infrastructure within this region.

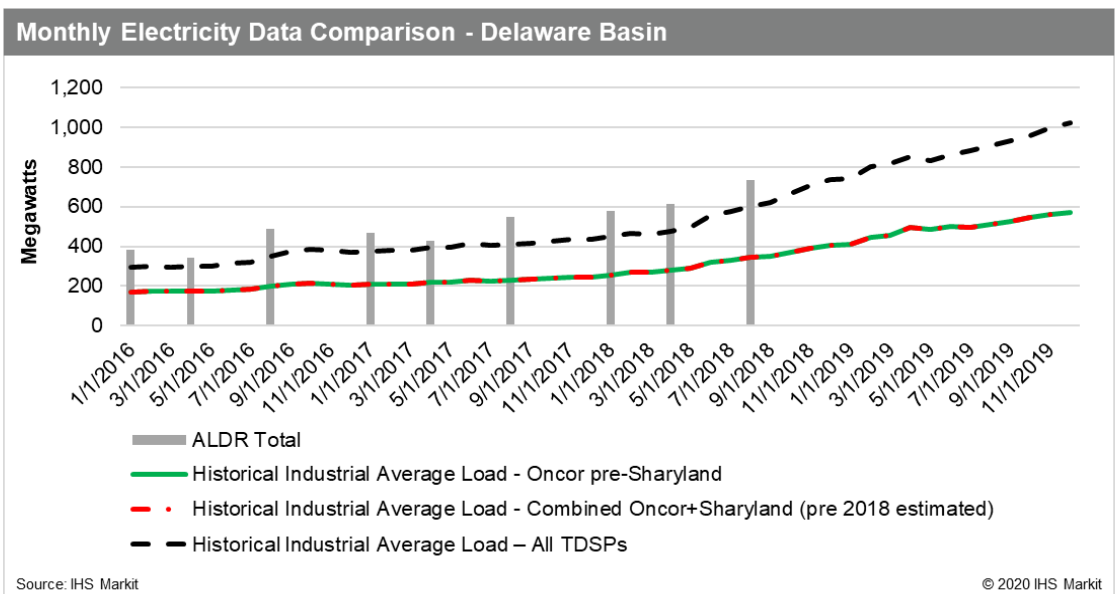


Figure 3-3: Monthly electricity data comparison for the Delaware Basin

Midland Basin: There has been steadily rising power demand in the region. The Sharyland acquisition in late 2017 had substantial impact, approximately doubling industrial power supplied by Oncor. Load factors are relatively low and have fallen in the past year (rising from about 0.4 to about 0.5 before falling to about 0.35), as max power increased substantially in 2019 (Fig. 3-4).

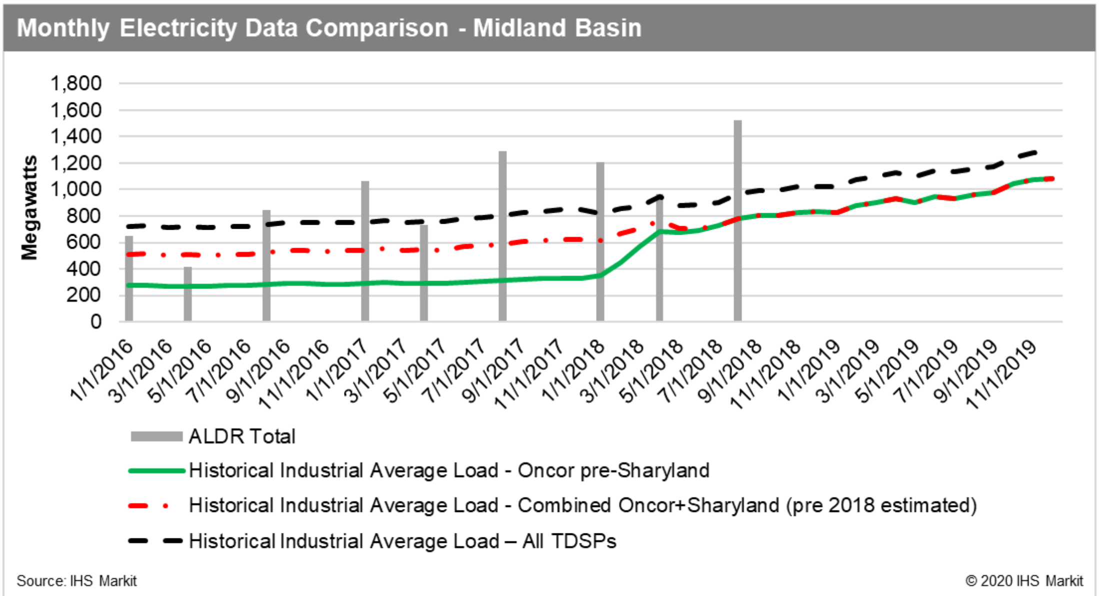


Figure 3-4: Monthly electricity data comparison for the Midland Basin

Fringe: The Fringe region has shown fairly stable power demand, strongly driven by industrial loads. Of the eight counties, only three have Oncor data contributing to the analysis; however, Oncor is a TDSP in Scurry County, which makes up over 70% of the total industrial power demand. Hence the uplift attributable to non-Oncor estimation is less than 30% of the region total. Load factors have been stable but low, generally around 0.35 (Fig. 3-5).

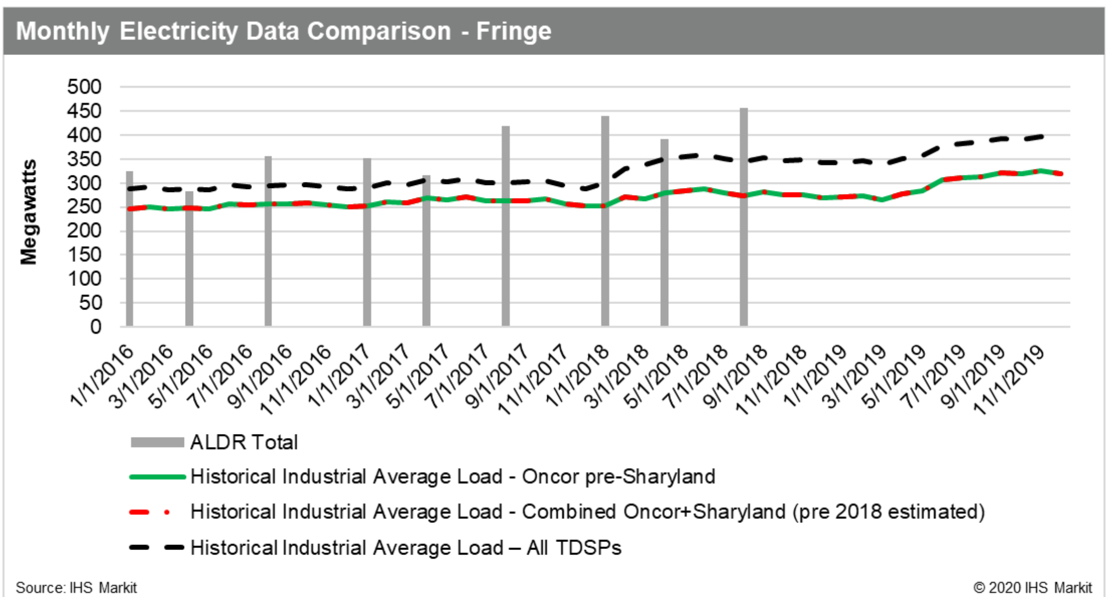


Figure 3-5: Monthly electricity data comparison for the Fringe area

3.3.1 Summary Results for Full Permian Basin

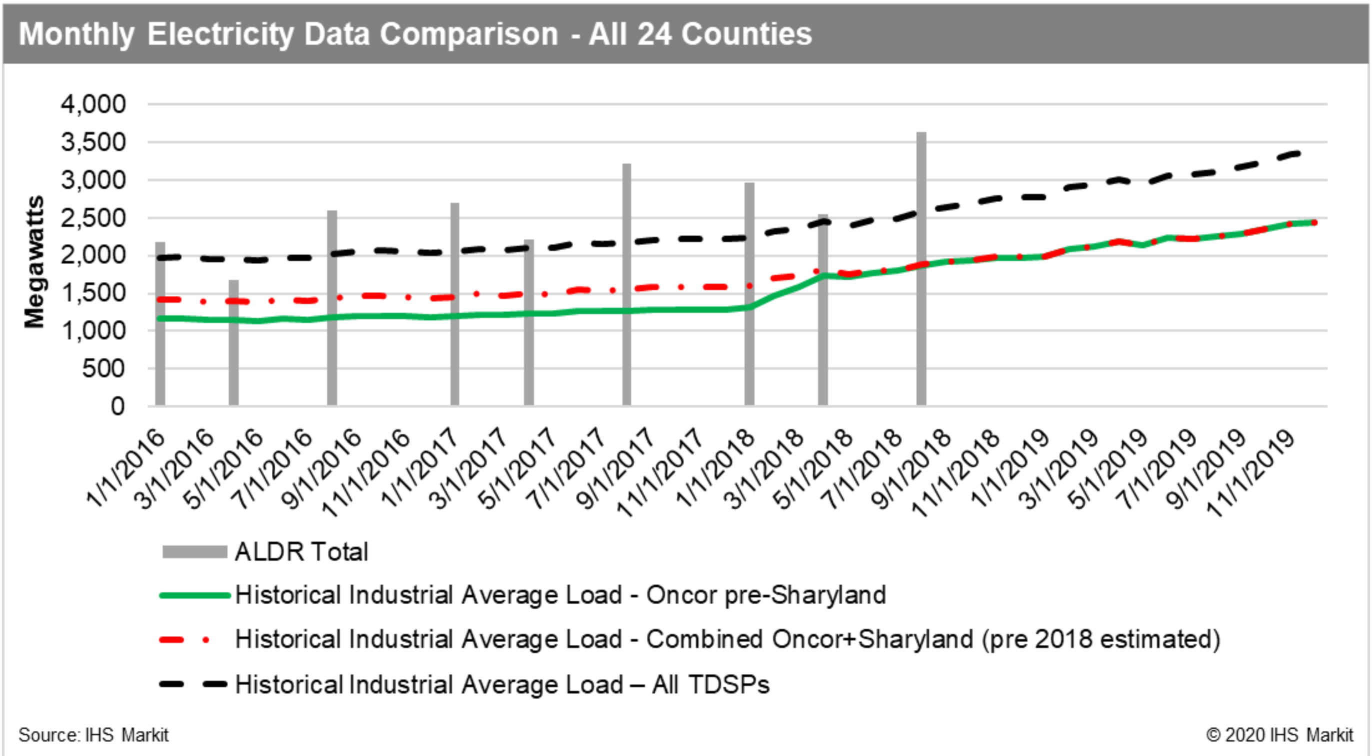


Figure 3-6: Monthly electricity data comparison – all counties

A rollup of all counties and regions provides us with an analysis of all 24 Permian Basin counties in the study. Figure 3-6 shows a gradual increase in the monthly billing for the combined counties. All figures show that growth became stronger in 2018. Industrial power usage grew strongly, from less than 2,000 MW in early 2016 to approximately 3,400 MW by the end of 2019. Over the four-year period, Oncor has provided service for over 70% of total power usage. By the end of 2019, Oncor provided almost 2,500 MW of the 3,400 MW total estimated average industrial power usage within the 24 counties.

3.4 Historical Industrial Power Supply and Demand by Sector

3.4.1 Introduction and overview

This section compares how closely industrial power demand correlates with historical oil and gas activity and power demand within each of the 24 counties and four regions. More specifically, this brings together all the analysis previously described, which includes converting monthly historical oil and gas related activities into power demand, as expressed by kW or MW, and comparing this with the adjusted Oncor supplied monthly billing analysis discussed previously. These comparisons were performed at the county level (see Figure 4-1 below), and then rolled up to the four regions and to the entire Permian Basin.

The purpose of this analysis is to (1) benchmark actual Oncor billing data with oil and gas activities, and (2) determine to what extent each county's oil and gas activity may be connected to the electric power grid.

3.4.2 Methodology

3.4.2.1 Graphical representations

Note that when referring to the Oncor monthly billing data, we are referring to the combined Oncor and other TDSP data, which were determined previously. Comparing oil and gas activity power demand with this metric is necessary since we are not able to differentiate those activities that may be supplied by Oncor vs. other TDSPs. Historic activities related to oil and gas power demand and shown on figure 4-1 and include:

- Upstream – Water disposal, tank electricity (related to SWD), rod pumps and ESPs
- Downstream – Gas processing electricity and oil and gas transport

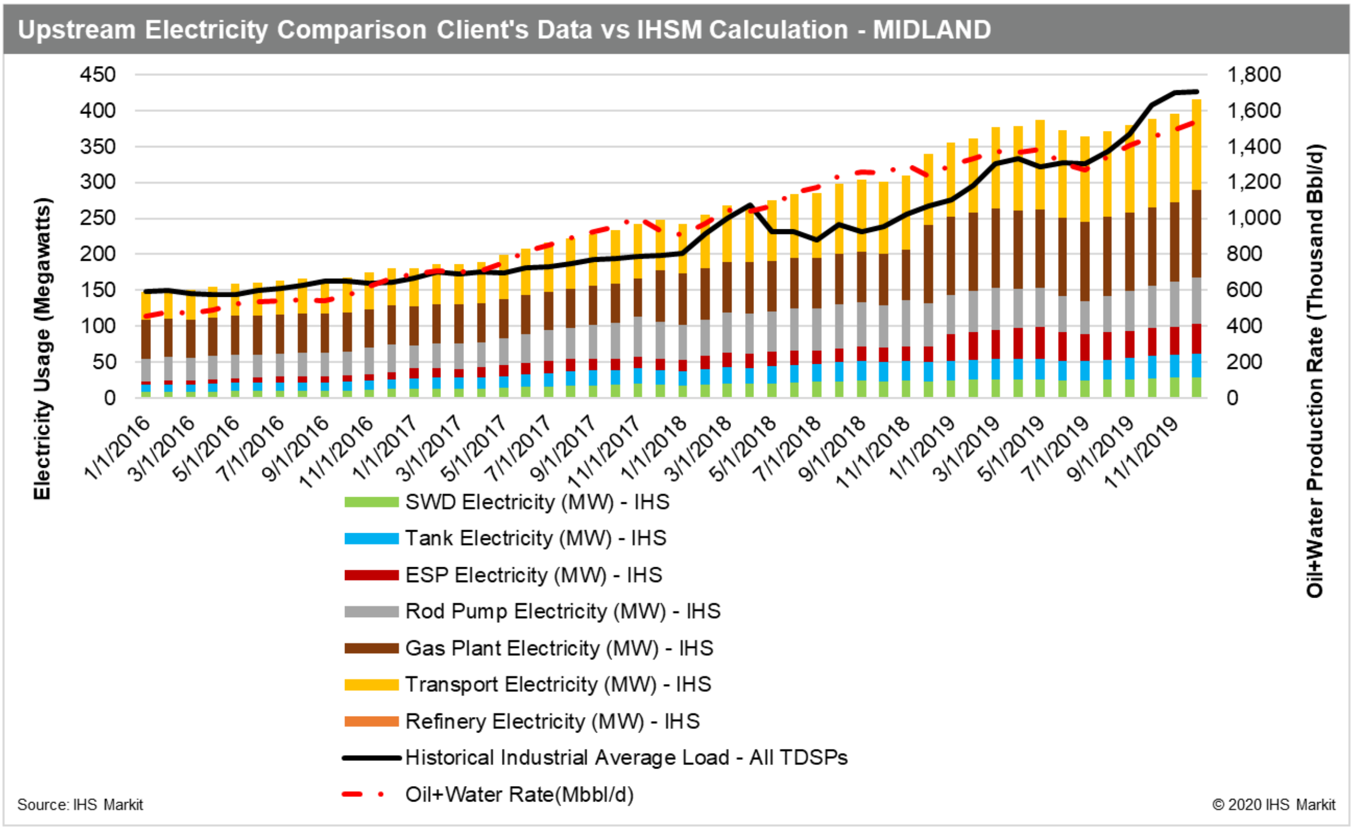


Figure 4-1. Upstream electricity comparison

- Refinery – while this captures refineries, it may also include other identified oil and gas activities such as sand mines and CO_2-EOR operations.

During the course of this analysis, we communicated frequently with Oncor to determine that within each specific county, the power demand due to oil and gas activity either equaled or exceeded the Oncor monthly billing data during the months comprising the 2019 time period, so as to account for all billed power usage. To help facilitate this comparative process, we used a three-month rolling average of Oncor monthly billing data. For several counties, particularly those spanning the Delaware sub-basin, the power demand associated with oil and gas activity exceeded the Oncor monthly billing data; hence, confirming that this excess is not yet connected to the electrical power grid.

3.4.2.2 Map view representations

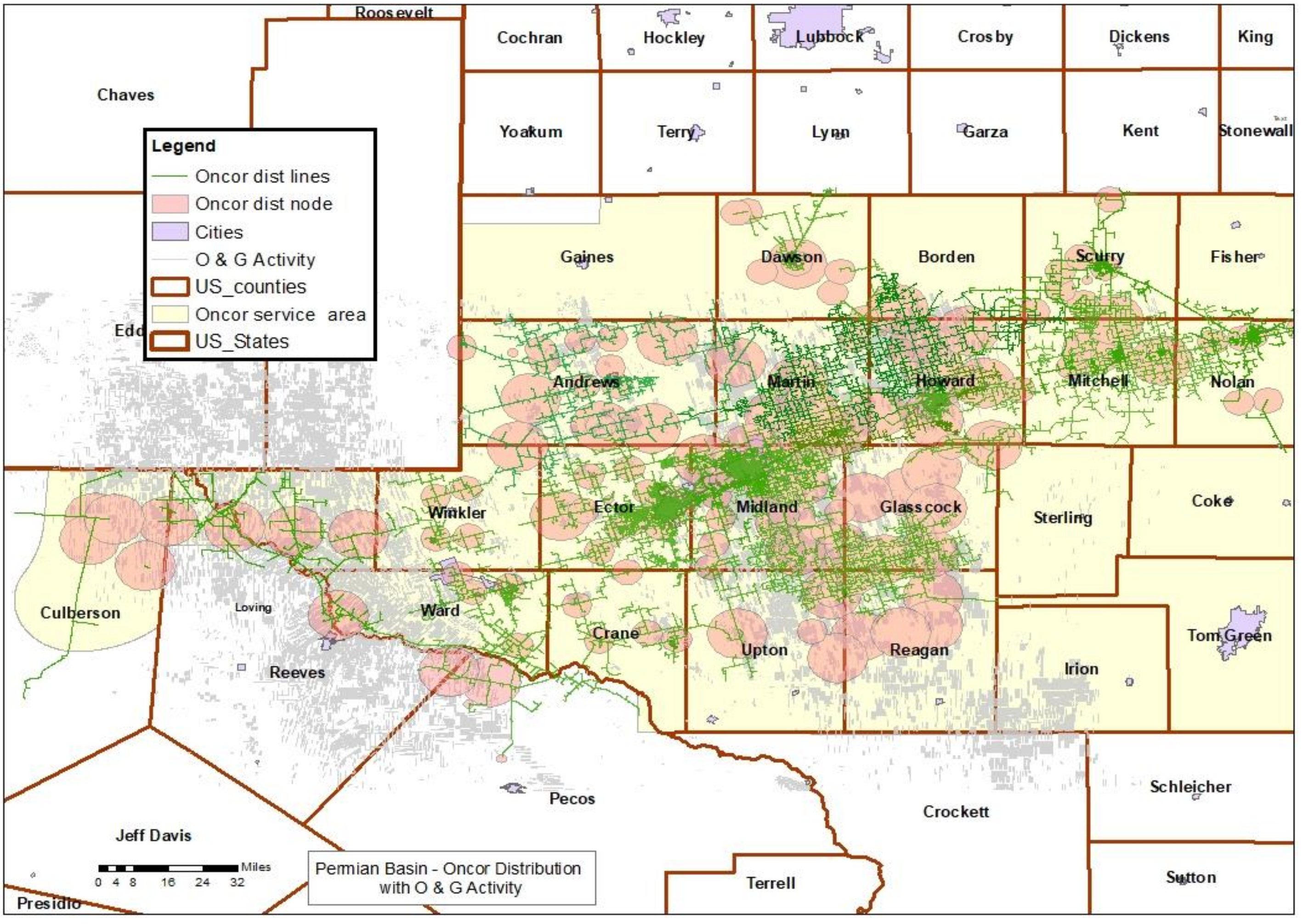


Figure 4-2. Regional electric distribution map

Regional Map of Oil and Gas Activity, Transmission and Distribution: During the course of the study several regional poster size maps were constructed to determine aspects pertaining to oil and gas activity such as well locations and patterns, pipeline locations and flows and locations of processing plants. When combining this we are able to ascertain key relationships and apply them. For example, we noted a number of processing plants near county borders that were geographically located in a county, but distribution lines from an adjacent county suggested that we assign the processing plant to the distributing county and not to the county location. This facilitated the correlations between oil and gas activities and monthly billing power usage.

A regional view of power distribution is set forth above in Figure 4-2 showing the extent of current distribution electrical grid in the Permian Basin. We note areas of high distribution concentration particularly near cities and towns; however, on closer examination, we see distribution extending out into the oil patch. A careful study of the map further helps us determine what activities may or may not be currently on the grid.

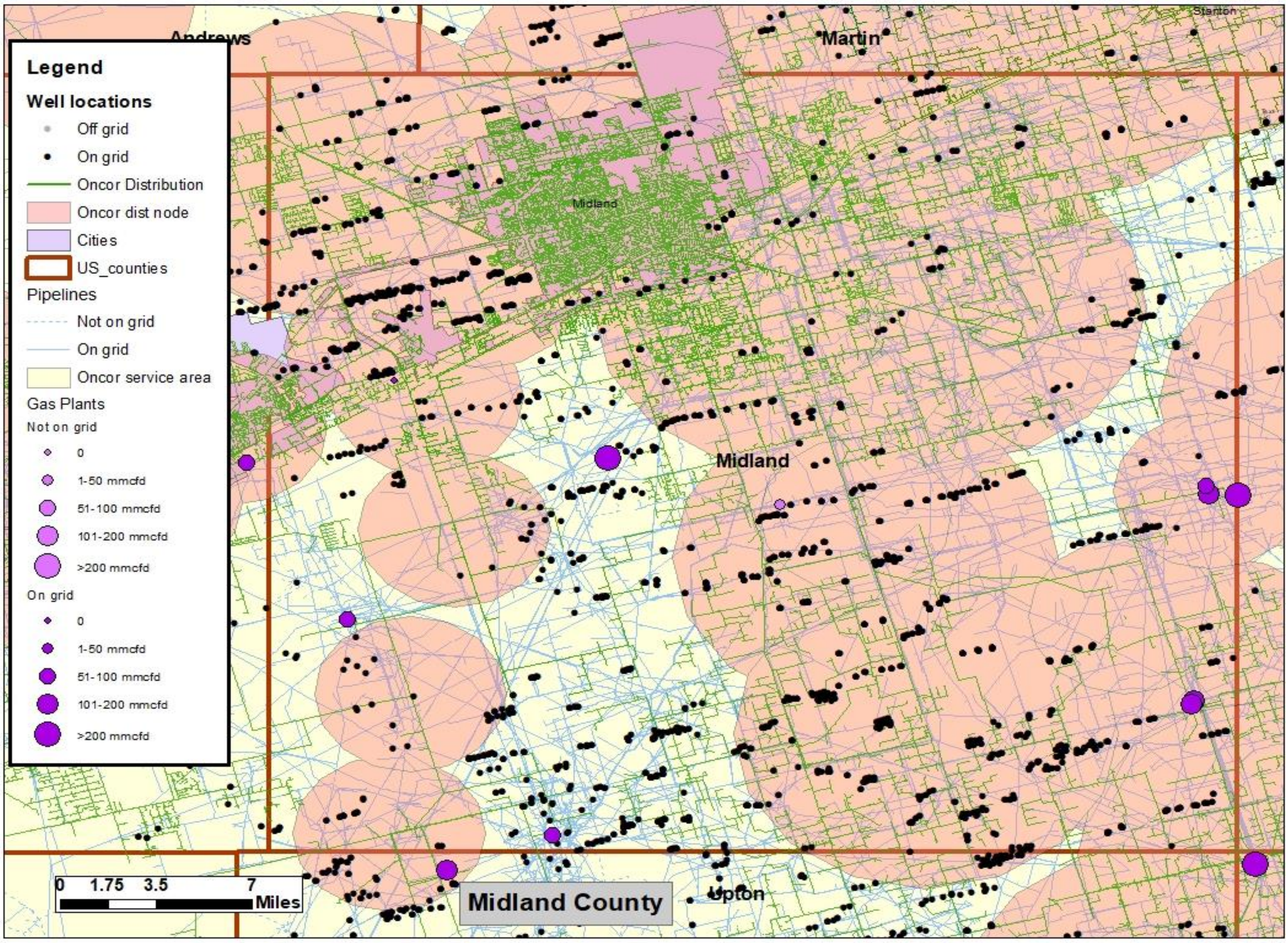


Figure 4-3. Midland county map showing oil and gas activity and electrical transmission

County level maps: Understanding geographically the relationships between oil and gas activity and electrical grid is critical to understanding how service providers transmit and distribute power within the Permian Basin. This analysis enabled us to (1) make some determination about the extent of oil and gas activities being on- or off- grid power, and (2) determine where power demand may grow in the future. In addition, this analysis helped us to compare and validate the results of the graphical work described above. Detailed maps were generated for each county (Figure 4-3 shows an example of Midland county map).

- Well surface locations (off grid and on grid)
- Pipelines (off grid and on grid)
- Gas processing plants (off grid and on grid, by processing capacity grouping)
- Transmission lines
- Oncor distribution lines, and territory covered
- Oncor distribution areas represented by the pink circles. Here Oncor determined that operations that were located within these areas would be serviced by Oncor and would be on the power grid.
- Cities

The maps were produced using both IHS Markit and Oncor supplied data. IHS Markit data provided county boundaries, transmission lines and cities, well locations and pipeline data. Oncor data provided the distribution lines and distribution service areas. The descriptions below correspond to the map shown after the descriptions.

- Well locations (on grid as black dots, and off grid as gray dots): IHS Markit has databases with existing well locations. The prevalence of the grid within 2 miles helped determine which wells were on grid vs. off grid.
- Oncor distribution lines (green lines), service area (in light red), and territory covered (in yellow): For Oncor distribution lines, IHS Markit has detailed mapping of power systems, and Oncor provided feedback when uncertainties arose, most frequently about territory available. Service area and territory covered are from Homeland Infrastructure Foundation-Level Data (HIFLD).
- Power lines (red lines) and electric plants (red squares): IHS Markit's databases concerning power provided this information, often originally provided by external HIFLD data.
- Cities (in purple): These are available in HIFLD data.
- Pipelines (on grid in solid gray lines, and off grid in segmented gray lines): These are available in HIFLD data, and then IHS Markit determined on grid vs. off grid depending on the grid availability.
- Gas processing plants (off grid with lighter purple circles and on grid with darker purple circles, by processing capacity grouping): IHS Markit has detailed lists of gas processing plants, including their size and operating status. IHS Markit used grid availability, and industry contacts to determine which gas processing plants were off grid vs. on grid.

3.4.3 Comparative Results by Region

Results for each individual county are discussed in Part 5. The analysis and conclusions presented here include a summary of the four study regions as well as a roll up of the entire Permian Basin. Historical estimates of monthly billing data for all counties as described previously are compared with oil and gas activity demand.

Central Basin Platform: This is a mature Permian Basin oil province that we expect about 95-100% to be on the grid. oil and gas activity will likely decline. As expected, it has been relatively stable, with modest declines in oil and gas activity attributable to oil + water production rates since mid-2019.

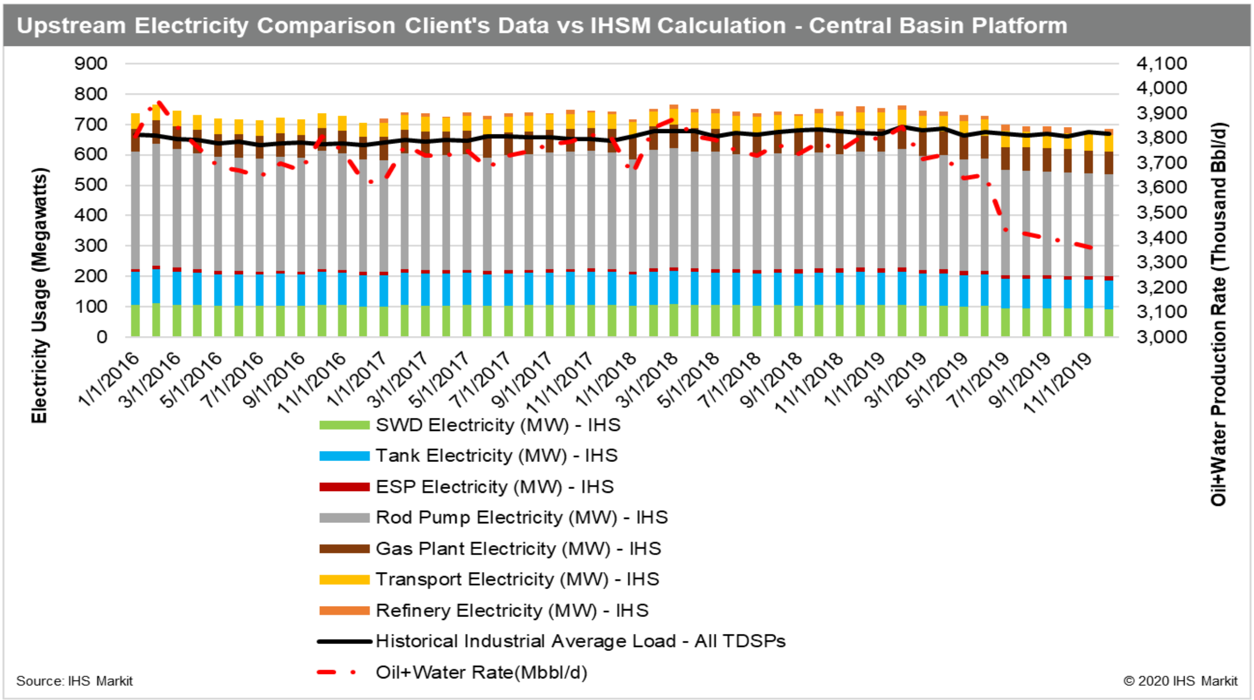


Figure 4-4. Central Basin Platform upstream electricity comparison

Oncor's industrial data approximates IHS Markit assessment of oil and gas activities as measured by MW estimates, and they have become even more similar in the past year, suggesting that some items previously not on the grid are now on the grid. During the last three months of 2019, the industrial billing data (power usage) averaged 668 MW, which was very similar to – and 96% of – IHS Markit's power demand estimates of 695 MW when aggregating oil and gas factors (figure 4-4).

Delaware Basin: This region has grown quickly so that values have more than doubled since early 2016. IHS MW estimates and oil + water rates have increased largely in sync. Oncor billing increased, but not at the same rate as growth in oil and gas activity. During the last three months of 2019, the industrial billing data (power usage) averaged

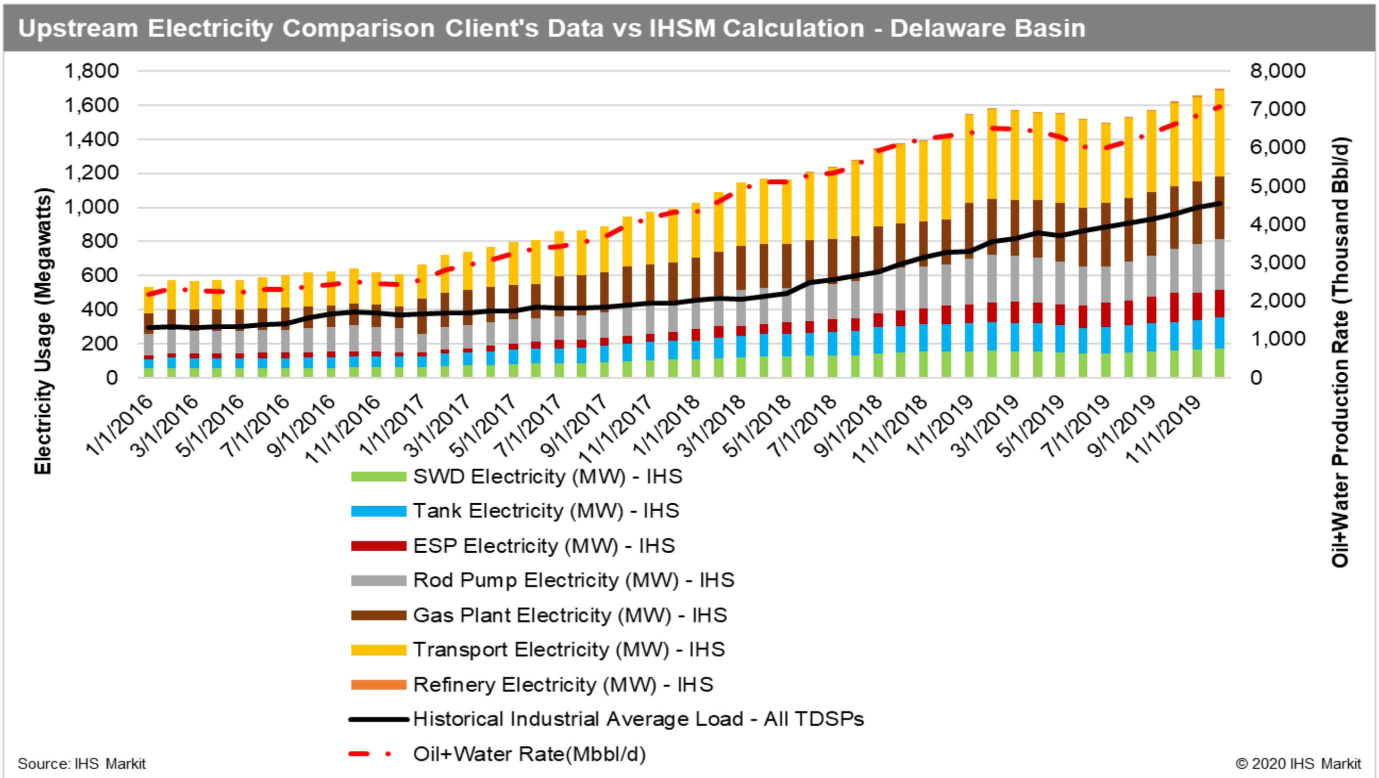


Figure 4-5. Delaware Basin upstream electricity usage comparison

around 990 MW, which was far short of and only comprised 61% of IHS Markit's power demand estimates of 1,640 MW when aggregating oil and gas factors. Notably, industrial power continued increasing through 2019 despite the slight decline in oil and gas activity, indicating that grid connections likely continued. Since Oncor's industrial power figure is lower than IHS Markit assessment of oil and gas activities as measured by MW estimates, it suggests that substantial oil and gas power demands remain off the grid (figure 4-5).

Midland Basin: All values have steadily risen since 2016, but the region has not increased as quickly as the Delaware. Relative to IHS Markit assessment of oil and gas activities as measured by MW estimates, power usage has grown somewhat faster, suggesting that the grid has recently been in the process of catching up with oil and gas activity. Oil + water rates have also grown slightly faster than IHS oil and gas activity estimates. Over the past year we have seen a convergence of power usage from billing data with power demand from oil and gas activities. During the last three months of 2019, the industrial billing data (power usage) averaged 1,269 MW, which was relatively close to IHS Markit's estimates (power demand) of 1,322 MW, or 96% of IHS Markit estimates (figure 4-6).

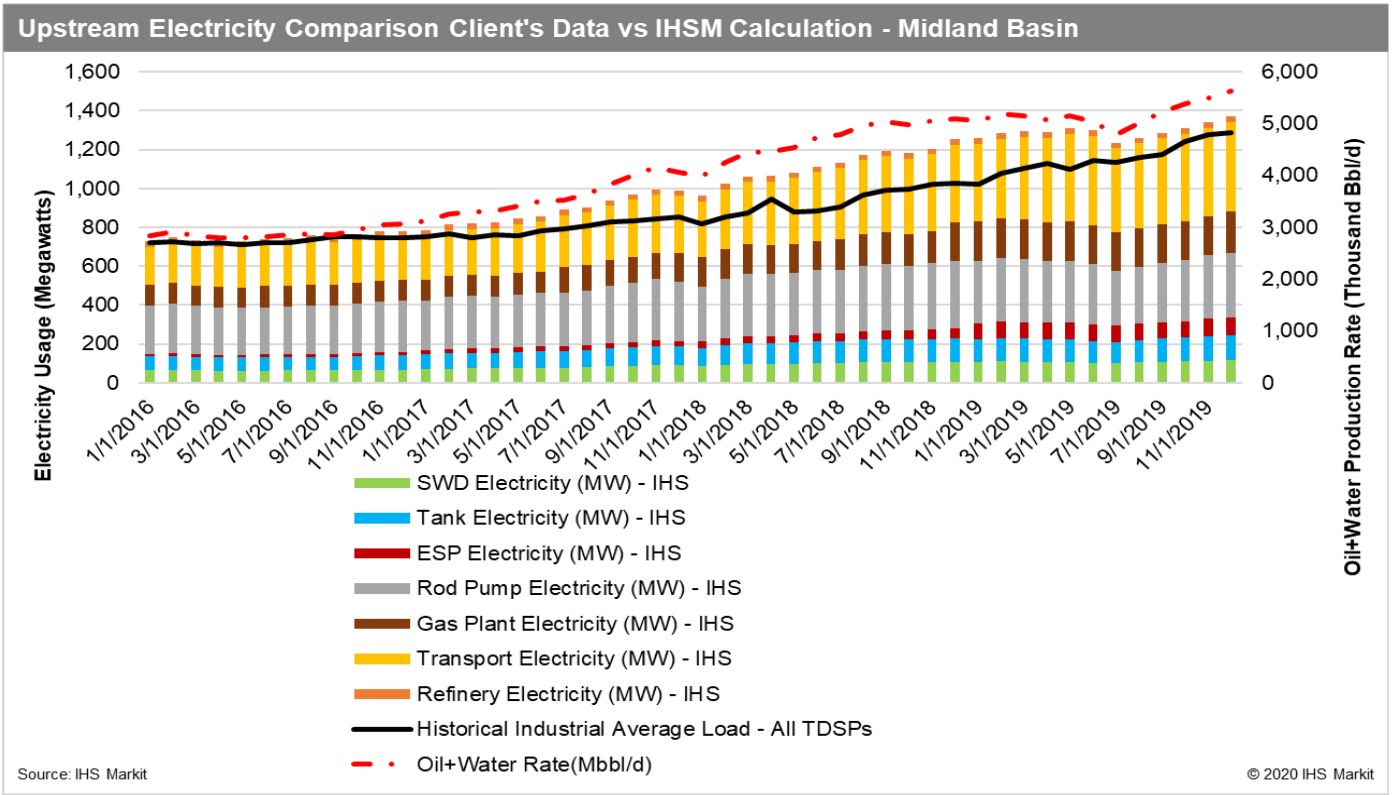


Figure 4-6 Midland Basin upstream electricity usage comparison

Fringe: The grid use is nearing 90%, nevertheless, fringe counties have remained relatively steady, as they are not part of the unconventional plays. IHS MW estimates increase slightly over the period, due substantially to growth in Scurry County. In 2019, the industrial billing data (power usage) averaged 393 MW, 90% of the 438 MW IHS Markit estimated (power demand) when aggregating oil and gas factors (figure 4-7).

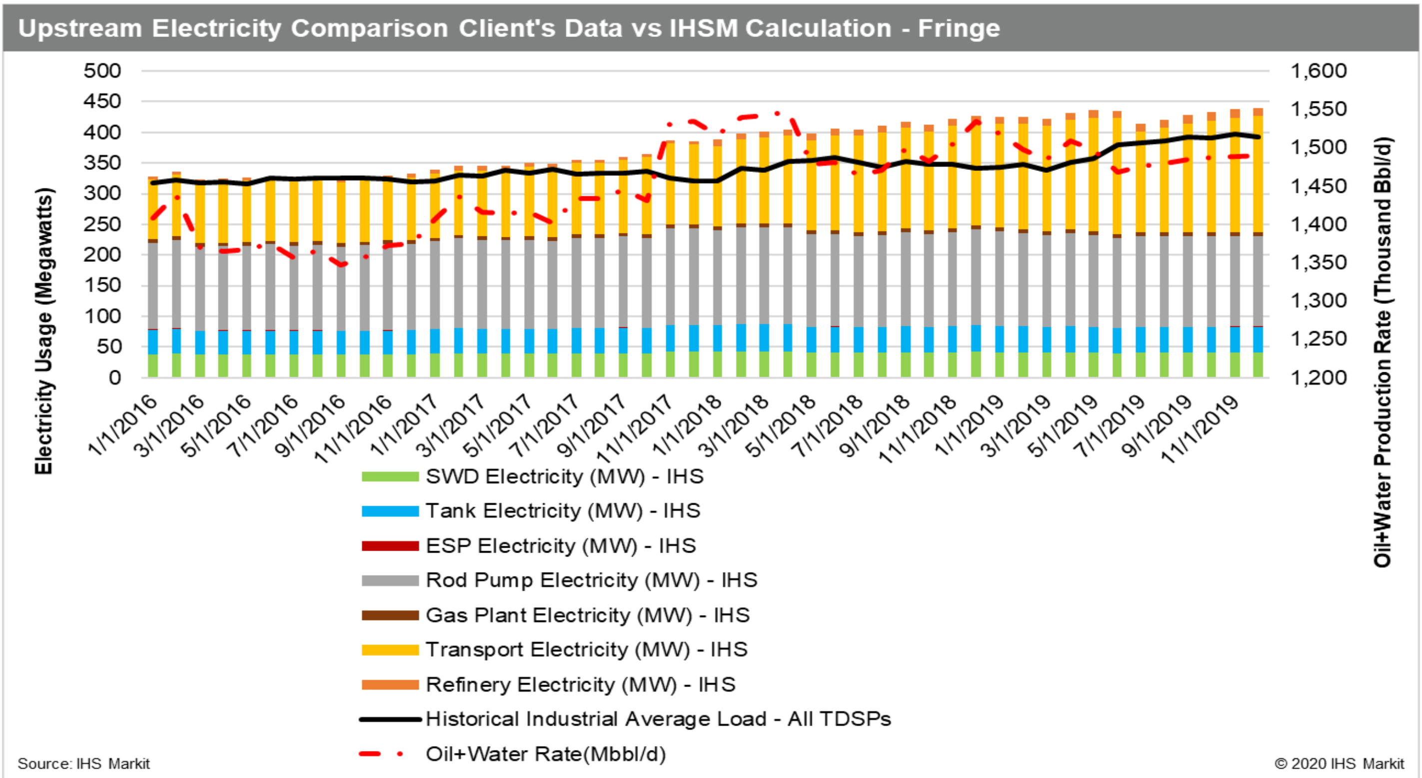


Figure 4-7. Fringe upstream electricity usage comparison

Summary of results by region: Summary averages for the latest three months of 2019 as shown on the graphs are summarized in table 4-1. Given that the Central Basin Platform (CBP) has an on-grid percentage of 96%, we would consider this to be the extent of the grid potential in that region. The Midland Basin grid connection has been growing rapidly but is approaching total grid connection in most counties. The Delaware Basin still has considerable grid connection growth potential ahead of it. Note that these calculations reflect contributions of all the 24 counties, including those not served by Oncor where we have estimated power demand.

Group	2019 O&G Activities (MW)	Oncor Billing Last 3 months 2019 (MW)	% On Grid - 2019 Avg (MW)	August 2019 Oncor Billing (MW)	August 2019 Peak Demand (MW)
Delaware	1,640	993	61%	909	1,073
Midland	1,322	1,269	96%	1157	1,306
CBP	695	668	96%	664	746
Fringe	438	393	90%	385	492
Total	**4,095**	**3,223**	**79%**	**3115**	**3,617**

Table 4-1: Comparison of oil and gas activity power demand with average monthly industrial power usage

Permian region: All the counties with Oncor power usage have been aggregated and the comparison is shown below in Figure 4-8. Power usage was about 3,223 MW average over the last three months of 2019, compared to oil and gas activity power requirements of 4,095 MW during the same period. For the forecast portion of this report, we are comparing August 2019 with August 2030, so we have added these values as a comparison baseline, which are also shown in the table 4-1 above.

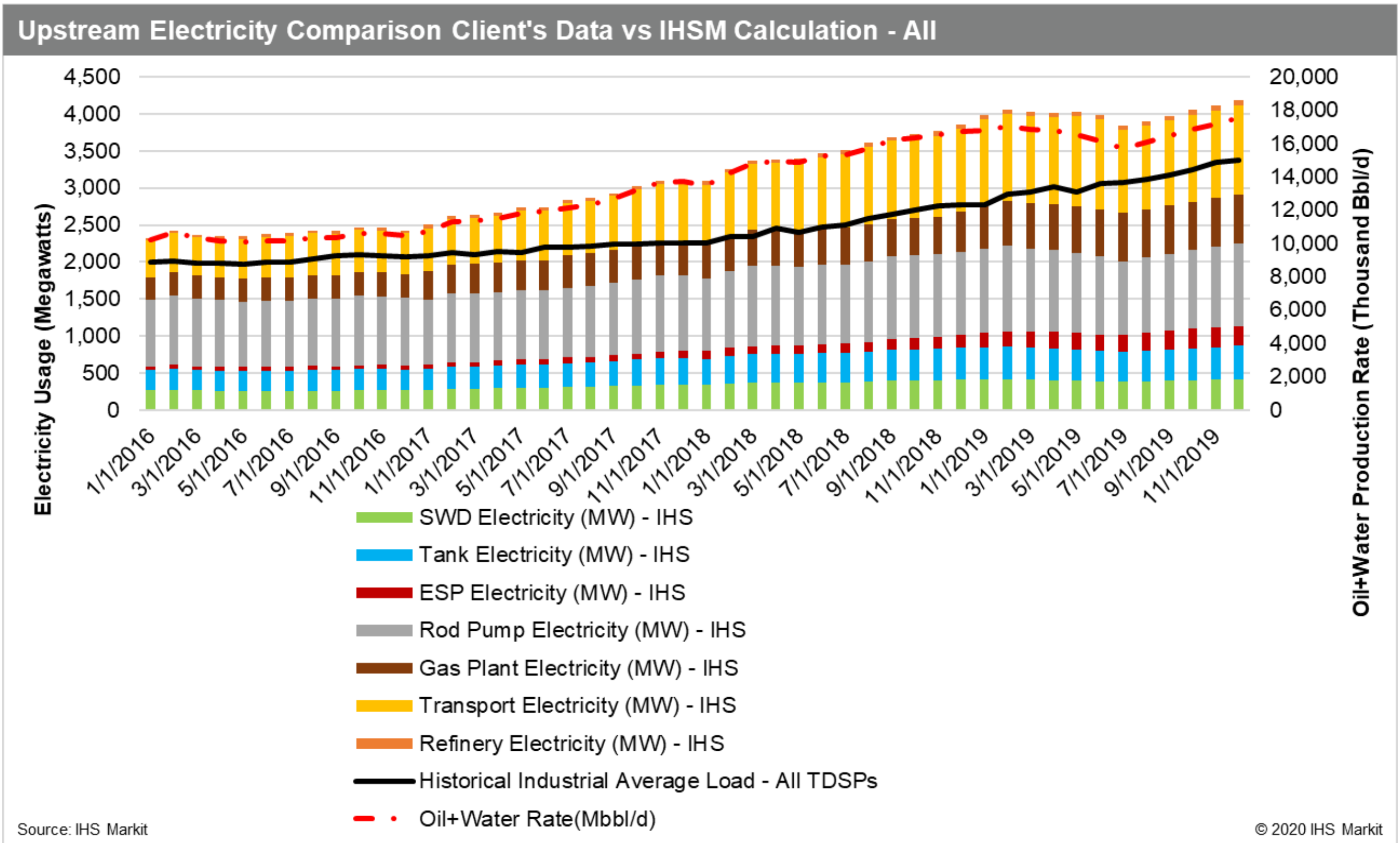


Figure 4-8. Summary of the upstream usage from oil and gas activities and Oncor billing data history

3.5 Forecasted Industrial Power Demand

3.5.1 Industrial Power Forecast Methodology

The initial result of the IHS Markit oil and gas power assessment closely relates to the expected average power, or sales in kWh divided by the number of hours in the sales time interval, because the IHS Markit power assessment in most cases was derived from either energy to power conversions or from averaging reported loads at the ERCOT system peaks. A representation of historical average power was calculated by IHS Markit from the Oncor sales data. After reviewing a variety of power datasets available from Oncor, the billing data was identified as the most comprehensive for estimating demand. Once the appropriate adjustments were made to Oncor's billing data, such as billing cycles and corrections, the resulting average power was determined as the reasonable proxy to inform the IHS Markit forecast.

Some oil and gas operations are self-powered and may never rely on the grid, and others are using generator power in anticipation of getting a grid connection IHS Markit's assessment of historical average industrial power demand is well above the average power based on Oncor's historical energy sales in most counties. This means expansion of the grid beyond what is required for new activity would help to supply loads currently not the grid. It was expected at the onset of developing the forecast that the grid is still being developed in some areas to provide access to oil and gas activities that are currently operating.

Forecasting Average Industrial Power Demand: IHS Markit has summed the average power estimates of all forward-looking upstream well operations, oil and gas transportation, gas processing plants, refineries and other minor activities. In order to summarize average demand outlook for each county, we analyzed each region and the overall Far West Texas weather zone covered by Oncor. Industrial items known to not draw grid power have not been included in the forecast (or the historical assessment). It is expected that there is a limit to ability of power infrastructure to provide power for the entire demand. During the forecast period, wells will start production before they are connected to the grid. IHS applied a limit of 97% of demand being met by grid power in any county as this has been our observation with historical trends in counties with mature oil and gas operations. It is possible for this to increase once the Far West Texas region electrical grid is fully developed and oil and gas activity has ceased, but this is not expected by 2030.

For each county, IHS Markit projected average industrial power figures starting from the latest reported average power figures converted from the adjusted Oncor billing data toward the total demand forecast made by IHS. The end of the monthly billing data can be seen in the chart below (figure 5-1) as the black line (Historical Industrial Average Load – All TDSPs). The forecasted average monthly power for all TDSPs (including Oncor) is the blue line in figure 5-1 (Forecast Industrial Average Load (IHS) – All TDSPs). For counties where billing data was not available, IHS Markit estimated the latest billing data by comparing the extent of grid coverage in county on a map to the total active areas in the county to generate a coverage ratio. The resulting ratio was applied to the IHS average power estimate to indicate current demand and the forecast starting point.

In cases where the historical or current oil and gas activity demand is greater than what was most recently reported in Oncor's sales data, (adjusted for other TDSPs and other issues already discussed), the supply was increased each period to close the gap between supply and demand to ultimately reach 97% of the total project industrial demand. The rate of power increase was determined by looking at recent trends in the Oncor billing data and continuing with those trends until the forecasted billing data reached 97% of the forecasted oil and gas activities, after which both forecasts continued along the same track (see figure 4-1).

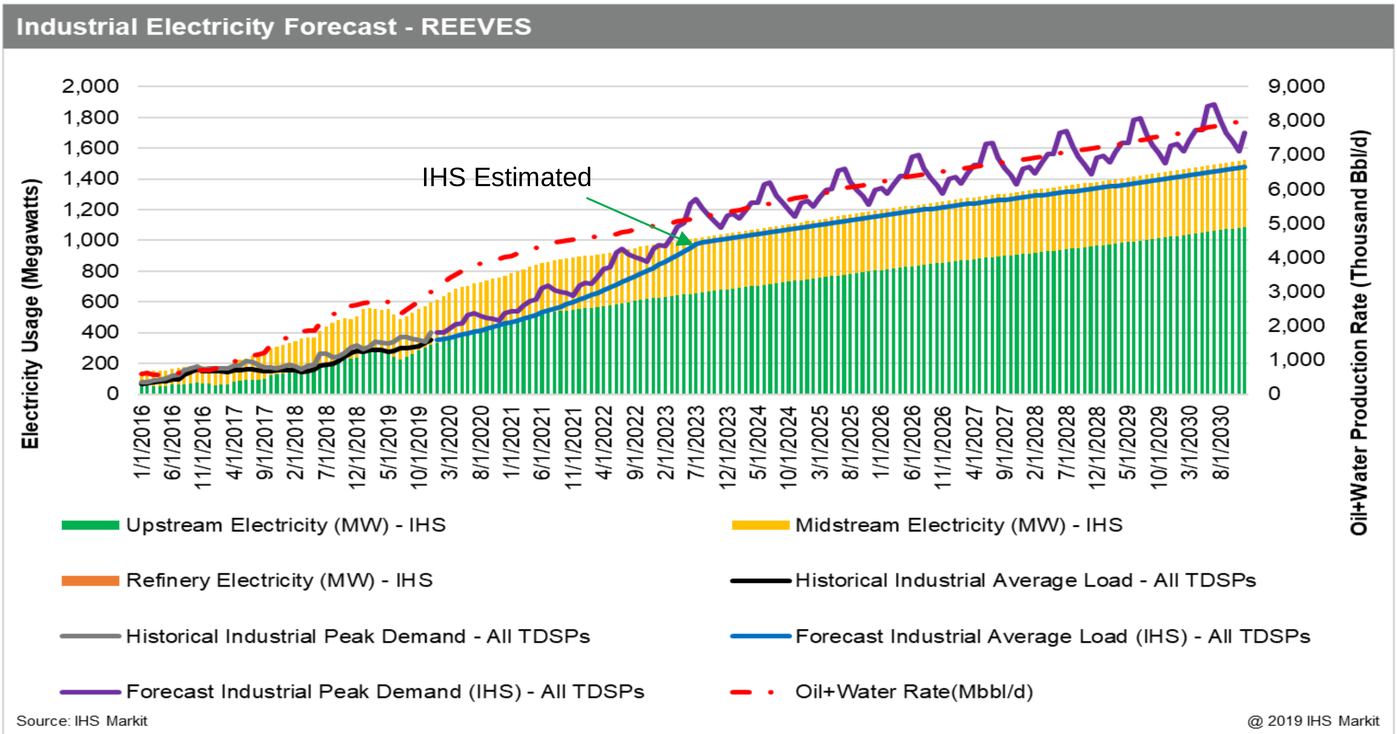


Figure 5-1. Industrial electricity forecast – Reeves County

Adjusting Average Industrial Power Demand to Peak Power: Since the IHS Markit power forecast for each county and region is initially at average power, it must be converted to peak. This adjustment must take place at each county separately, so a monthly load factor for each county is required to convert average power to peak power demand by month. In order to do this, IHS Markit analyzed 15-minute interval load data provided by Oncor. IHS Markit calculated the applicable load factors, and IHS Markit identified the peaks of the power shapes from each month of data to compare it to the energy billed in each corresponding month. The application of this process to the historical power data can be seen in the chart above. Applying the monthly load factors in Reeves county to the black line representing the historical 3-month moving average of average power, calculated from the sales data, moves it to the dark blue-green line, which represents the historical peak for each month.

The calculation of the Load Factor:

$$\text{Load Factor} = \frac{kWh(average\ electric\ consumption\ in\ \boldsymbol{Energy}\ over\ billing\ period) \times 100\%}{Peak\ Kwh \times Hours\ in\ billing\ period}$$

Since IHS has forecasted power (kW), rather than in energy (kWh), the load factor was applied after removing the temporal concept, leaving it like this:

$$\text{Load Factor} = \frac{kW(average\ electricity\ consumption\ in\ \boldsymbol{Power}\ over\ billing\ period) \times 100\%}{Peak\ kW}$$

Load factor data is used to gross up the projected average power figures to a forecast of the peak industrial power, which will be calculated for each county by month. The chart below (figure 5-2) is an example of the load factors calculated for a county. The red line is the load factor for each month from the 15-minute interval data. It describes the relationship between the maximum load and average load. The ratio is used to adjust upward the sales data provided by

Oncor. The sales data used in this case was adjusted to the 3-month moving average since the billing cycles and back payments had created some distortion.

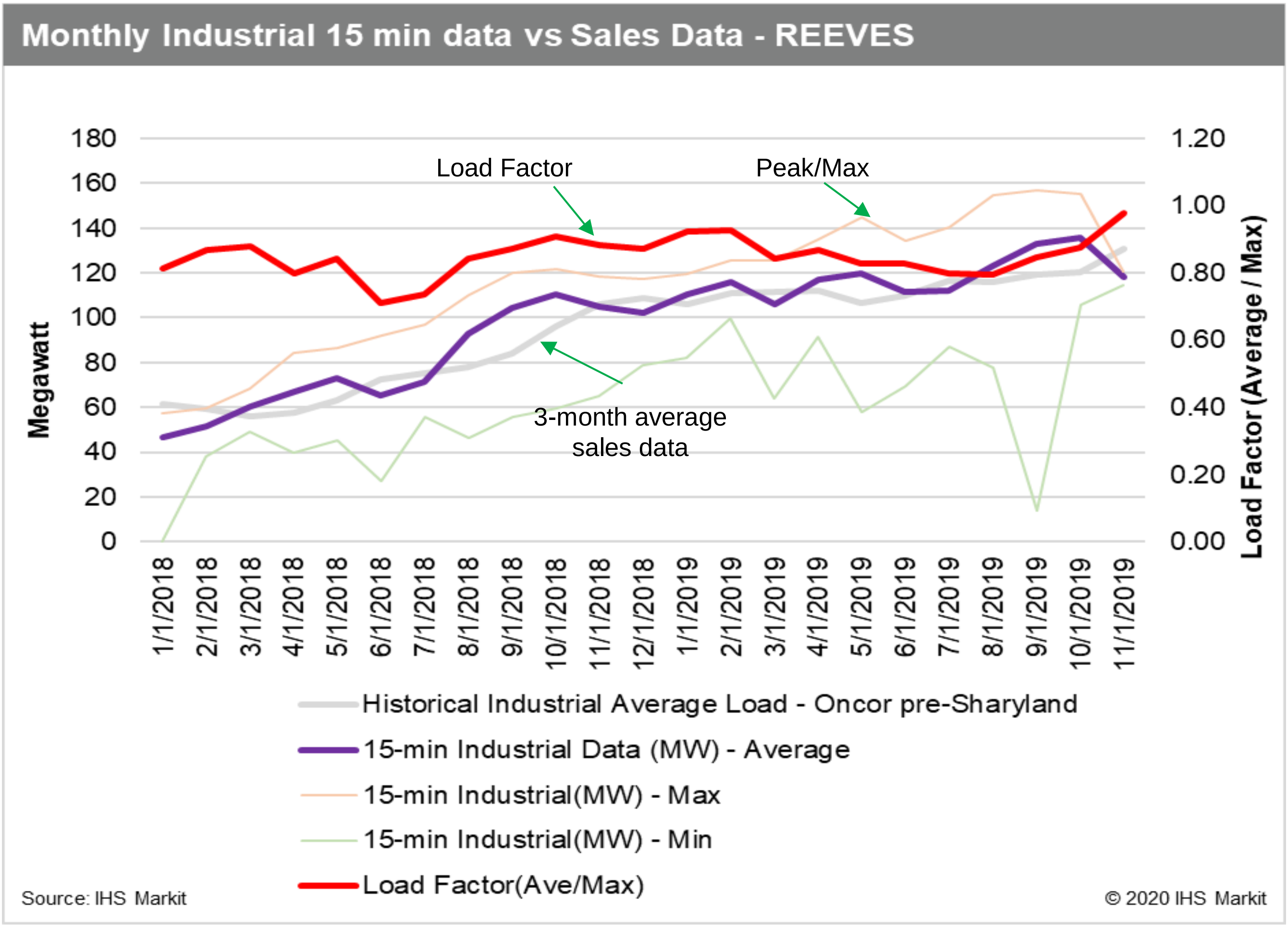


Figure 5-2. Monthly industrial 15 min data vs sales data – Reeves County

Applying Load Factors to the IHS Average Power Forecast: Some counties were found to have a varying use of power with load factors as low as 0.33 in Borden and 0.40 in Pecos. Load factors for most counties ranged from 0.75 to 0.95. Where 15-minute interval data included 2 years of data (i.e. two months of data for each month) for a county, the average of each month's load factor was applied on a forward-looking basis to each corresponding month in the forecast. The load factors applied, though similar to the raw data, were slightly less extreme due to nature of averaging numbers see figure 5-3_.

	15 Minute Data (2018 & 2019)		Applied in Forecast	
County	max	min	max forecast	min forecast
ANDREWS	0.97	0.92	0.96	0.94
BORDEN	0.47	0.33	0.46	0.36
CRANE	0.94	0.90	0.93	0.91
CULBERSON	0.97	0.78	0.88	0.81
DAWSON	0.97	0.81	0.94	0.89
ECTOR	0.93	0.88	0.93	0.88
GAINES	0.96	0.77	0.88	0.79
GLASSCOCK	0.91	0.78	0.91	0.78
HOWARD	0.96	0.88	0.93	0.91
LOVING	0.97	0.81	0.89	0.81
MARTIN	0.95	0.80	0.94	0.86
MIDLAND	0.95	0.91	0.95	0.91
MITCHELL	0.96	0.72	0.91	0.75
PECOS	0.83	0.40	0.75	0.61
REAGAN	0.90	0.78	0.90	0.83
REEVES	0.98	0.71	0.93	0.77
UPTON	0.95	0.79	0.95	0.86
WARD	0.94	0.91	0.94	0.91
WINKLER	0.98	0.80	0.93	0.83
CROCKETT	No data	No data	0.91	0.75
IRION	No data	No data	0.91	0.75
STERLING	No data	No data	0.91	0.75
SCHLEICHER	No data	No data	0.91	0.75
SCURRY	No data	No data	0.93	0.91

Figure 5-3. Monthly Load factors by county – note that all factors are monthly max, min, etc.

Once the load factors are applied to the IHS Markit average power forecast, we can see the IHS Markit forecast moves upward from the average power forecast. In the chart below, the peak power forecast can be seen in purple (Peak Forecast on Grid Total Electricity) above the blue forecast line. Now the purple line is in sync with the historical sales data that had been adjusted to peak in dark blue-green (Peak 3-month moving average). The peaks and troughs of the purple line reflect the range of the load factors calculated from month to month. The distance from the peak to the trough is quite pronounced for Reeves County, since the highest load factor applied in its forecast is 0.98 and the lowest applied is just 0.77 (figure 5-4).

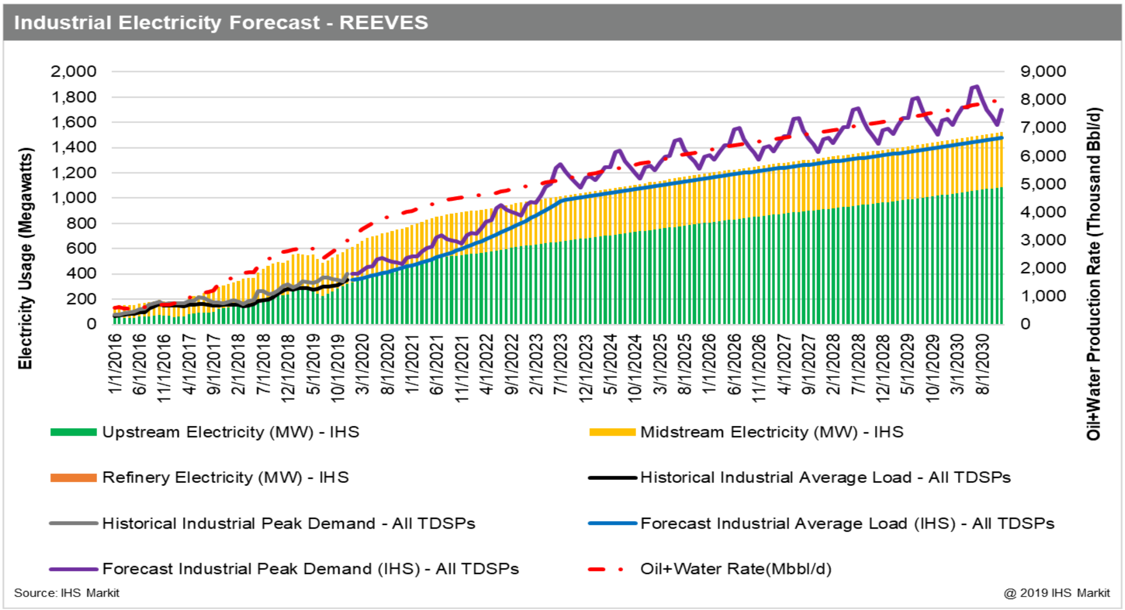


Figure 5-4. Industrial electricity forecast with peak forecast on grid total electricity – Reeves County

3.5.2 Power Forecast by Region

Figure 5-5 depicts the total power demand forecast and the total of all peak demand from all of the combined 24 Permian Basin counties in this report. No inter-county coincidence factors have been applied to the summed peaks, but it still provides an indication of the total power required. The chart reveals that while the current average oil/gas load is just over 4,095 MW as shown in the stacked bars, the grid serviced peak is just over 3,223 MW. Peak demand supplied is expected to grow dramatically over the next 10 years. By 2030 peak power demand is expected to be around 8,725 MW with industrial grid coverage in the region expanding from 79% served in late 2019 to 97%. Note that the peak demand shown on figure 5-5 was derived by summing all of the individual county peak demand forecasts. Given the non-seasonal nature of industrial peak demand individual county-level peaks will have occurred at any given month, which means that the basin level and regional level roll-ups would technically be considered coincident for all counties contributing to each respective roll-up.

As previously stated, we observe that grid connection in very mature areas such as the Central Basin Platform, which has been producing for decades, is at 96%. We believe that it will be difficult to achieve 100% grid connection in all areas, including emerging areas and thus have determined that 97% total grid connection would be an appropriate conservative assumption pertaining to full grid connection. As the forecasted average usage increases, we note that the peak demand also increases commensurately by a similar percentage uplift.

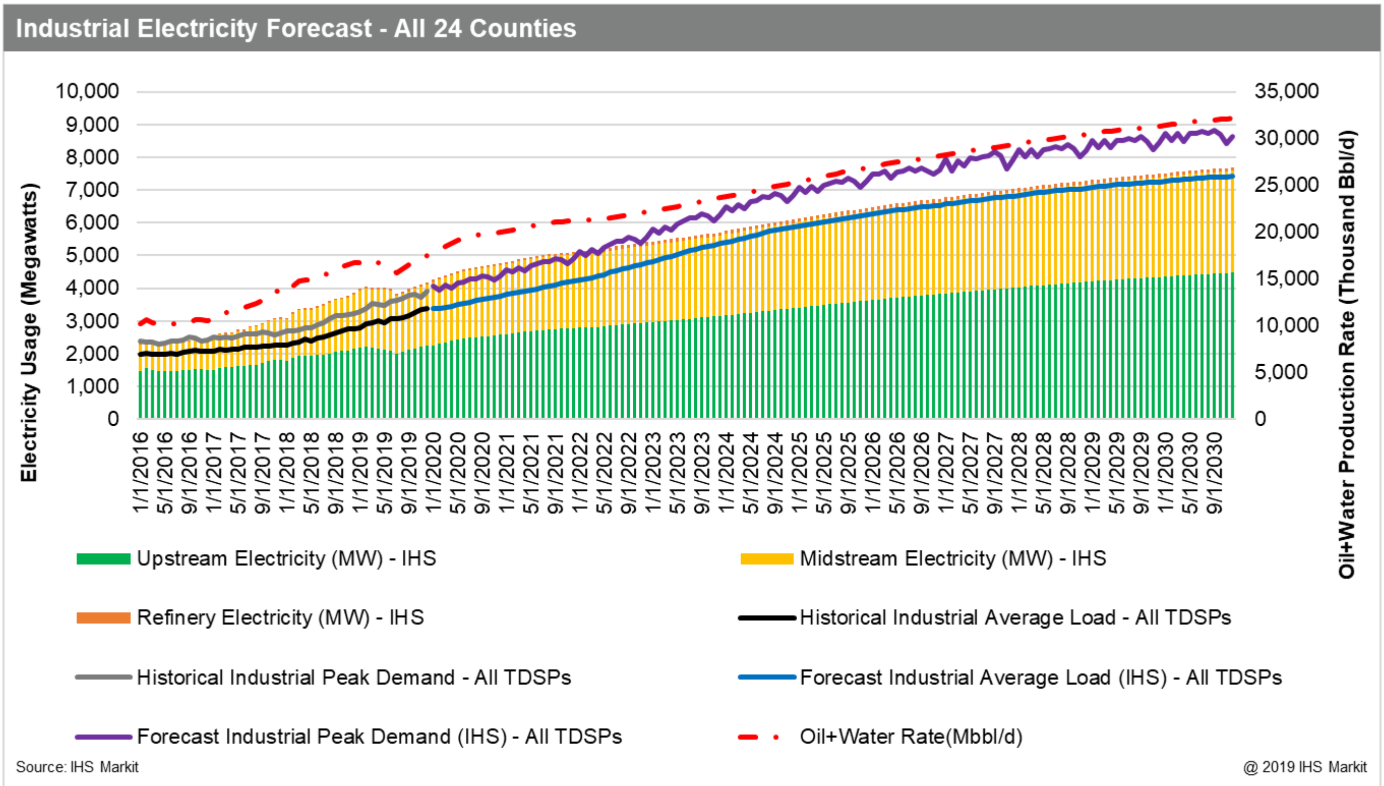


Figure 5-5: Industrial electricity forecast – All counties

Delaware Basin: The chart below (figure 5-6) shows the total average forecast and the total of all peak demand from Delaware Basin counties. No inter-county coincidence factors have been applied to the summed peaks, but it still provides an indication of the total power required for the Delaware Basin. The chart reveals that the current average oil/gas activity demand is 1,664 MW, and the serviced demand peak is just under 1,200 MW. Supplied demand peak power is expected to nearly quadruple over the next 10 years. By 2030 peak oil/gas load is expected to be near 4,800 MW with industrial coverage expanding from 61% to 97% over the forecast period.

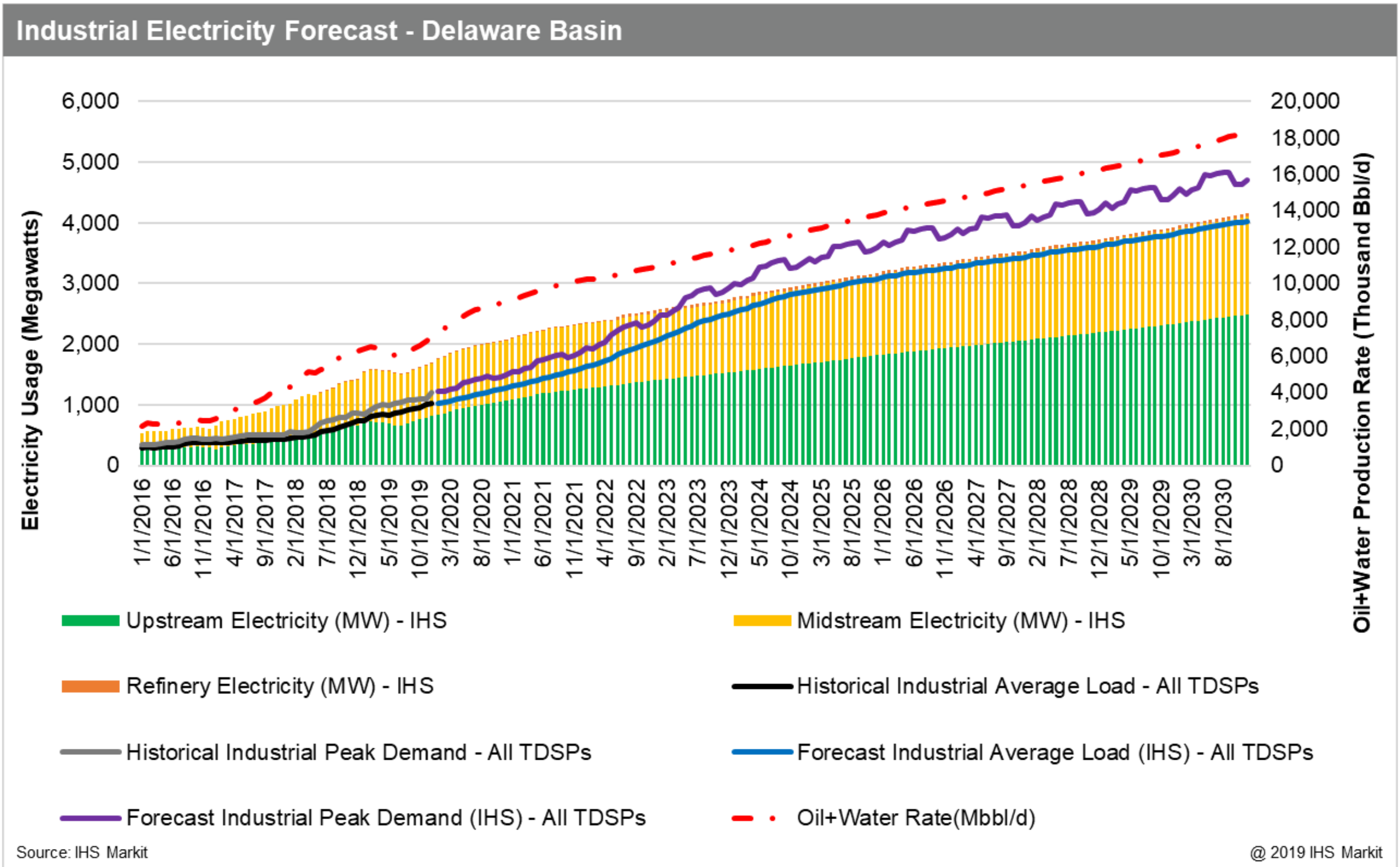


Figure 5-6. Industrial electricity forecast – Delaware basin

Midland Basin: The total average forecast and the total of all peaks from Midland Basin counties can be seen in the chart below (figure 5-7). No inter-county coincidence factors have been applied to the summed peaks, but it still provides an indication of the total power required for the Midland Basin. The chart reveals that the current average oil/gas activity demand is 1,322 MW, and the serviced demand peak is just over 1,500 MW. Peak oil/gas load is expected to more than double over the next 10 years, but demand will wane towards the end of the decade. By 2030, demand peak oil/gas load is expected to be near 2,500 MW, with industrial coverage expanding slightly from 96% to 97% over the forecast period.

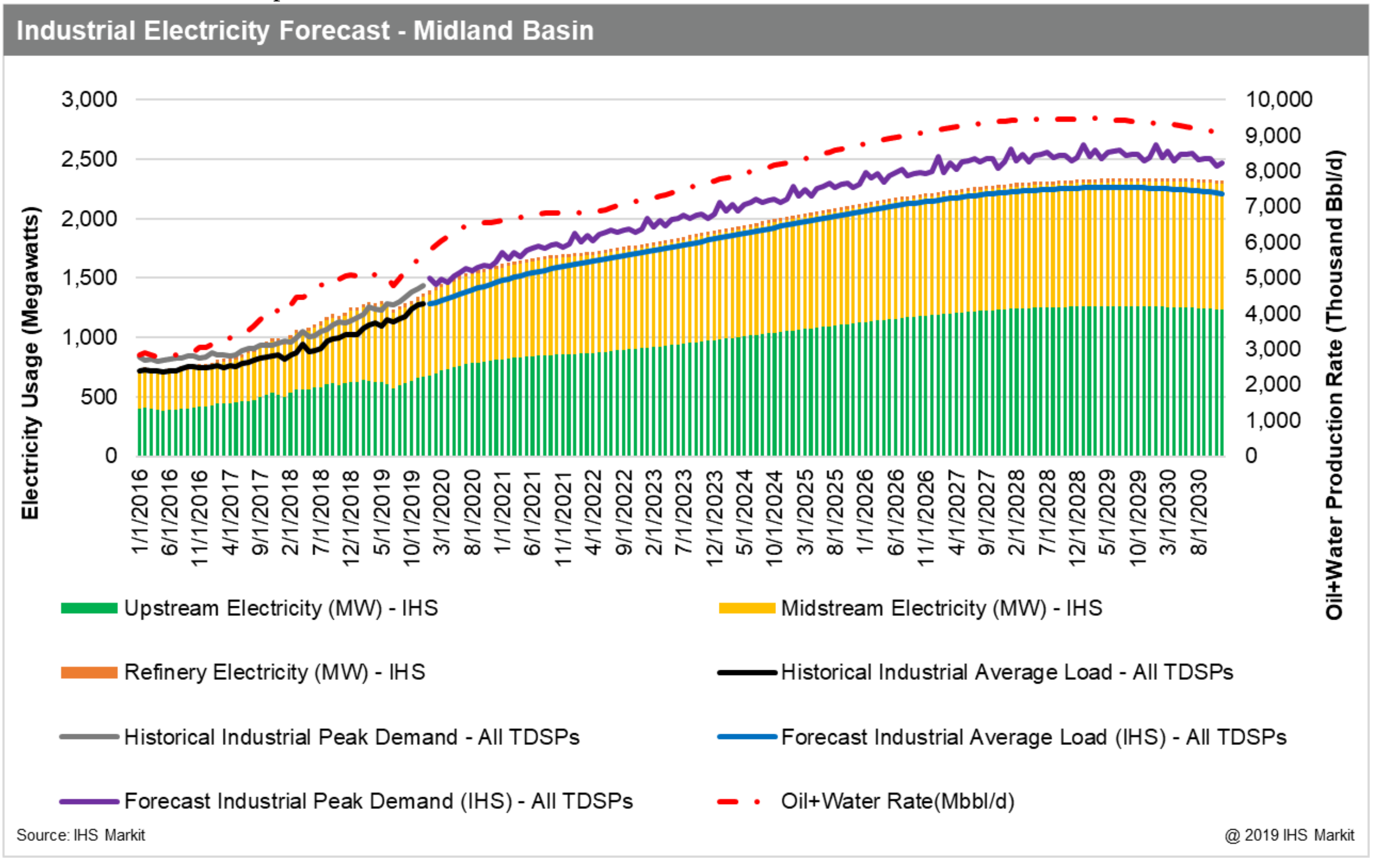


Figure 5-7. Industrial electricity forecast – Midland Basin

Central Basin Platform: The total average forecast and the total of all peaks from Central Basin Platform counties can be seen in the chart below (figure 5-8). No inter-county coincidence factors have been applied to the summed peaks, but it still provides an indication of the total power required for the Central Basin Platform. The chart reveals that the current average monthly billing is 695 MW, which is about 90% of the current oil and gas activity. The oil and gas activity is expected to drop in the near future, which will align with the monthly billing. The demand peak (represented by peak demand lines on the graph below) is just under 750 MW and will decrease slightly in conjunction with the projected decrease in monthly power billing. With little change in oil and gas activity forecasted, and most industrial loads supported by the grid already, peak demand supplied by the grid will remain relatively flat in the Central Basin Platform for the next 10 years.

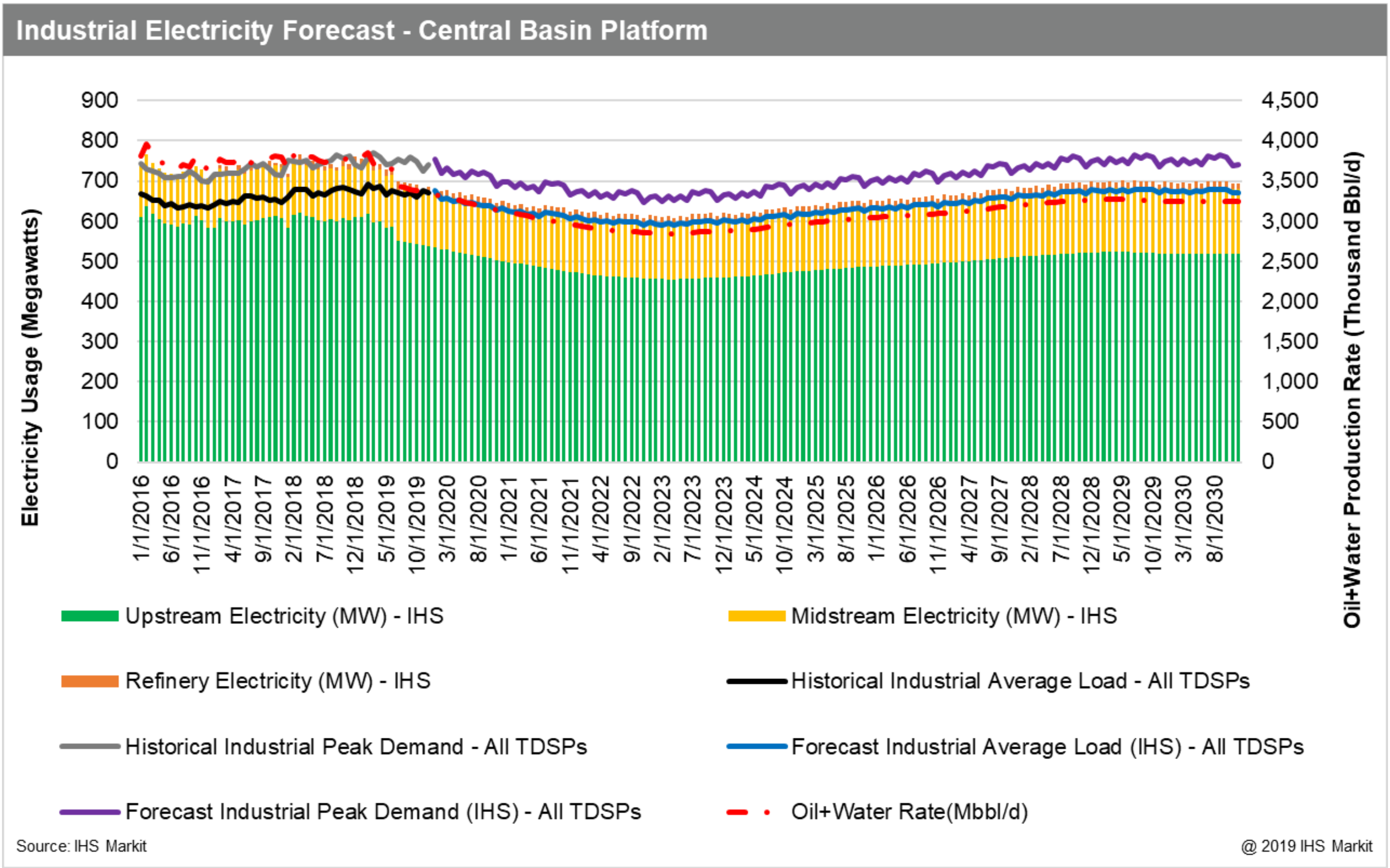


Figure 5-8. Industrial electricity forecast – Central Basin Platform

Fringe: The total average forecast and the total of all peaks from Fringe area counties can be seen in the chart below (figure 5-9). These counties are near the extent of the Permian footprint and hold less oil and gas potential than their counterparts in the Midland and Delaware basins. No inter-county coincidence factors have been applied to the summed peaks, but it still provides an indication of the total power required for the Fringe area counties. The chart reveals that the current average oil/gas activity demand is 438 MW, and the serviced peak is just over 500 MW. Peak power supplied is expected to only increase slightly over the forecast period. By 2030 peak demand is expected to be just over 600 MW.

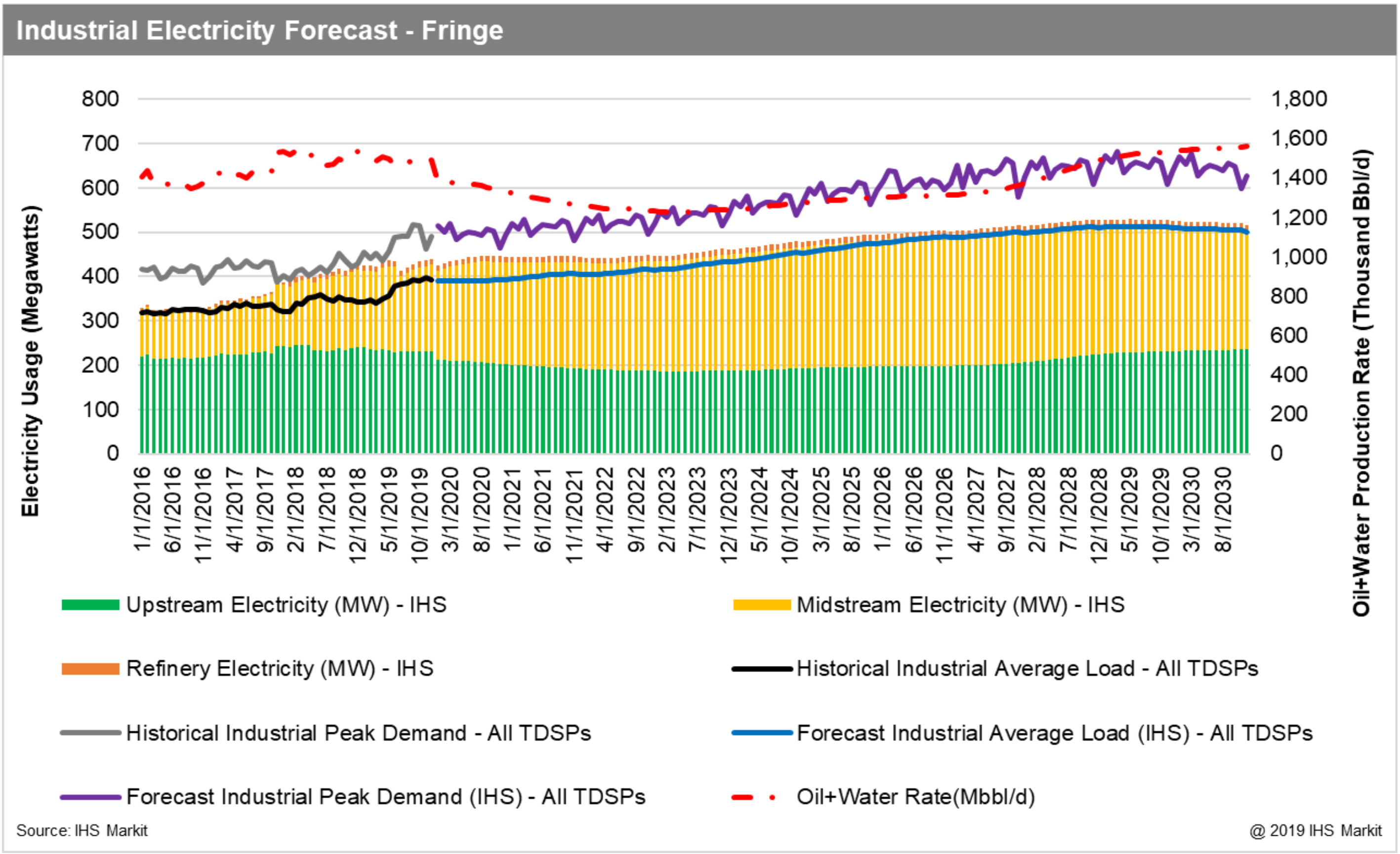


Figure 5-9. Industrial electricity forecast – Fringe counties

3.5.3 Growth in Industrial Power Supply

Growth in power supply for the four regions is represented in figure 5-10 where current peak demand of August 2019 is compared to forecasted peak demand in August 2030. Current peak demand in the basin stands at 3617 MW and is expected to grow to a peak demand of 8725 MW by 2030.

Overall, the area with the most change in energy in absolute and percentage terms will be in the Delaware region with an increase in peak industrial demand of 3,759 MW. This region is also where the most productive Permian areas are located, and where the most growth in oil and gas is expected. The Midland region is also quite prospective for oil and gas activities, but only 1,193 MW of industrial power is expected to be added to the peak demand over this forecasted interval. The Fringe area is also expected to see some increase in oil and gas activity, but this is limited compared to either the Midland or Delaware regions with peak industrial power here is only expected to increase by 147 MW. The Central Basin Platform region will not be an area of growth for industrial power, but industrial power use will be sustained near its current level through 2030.

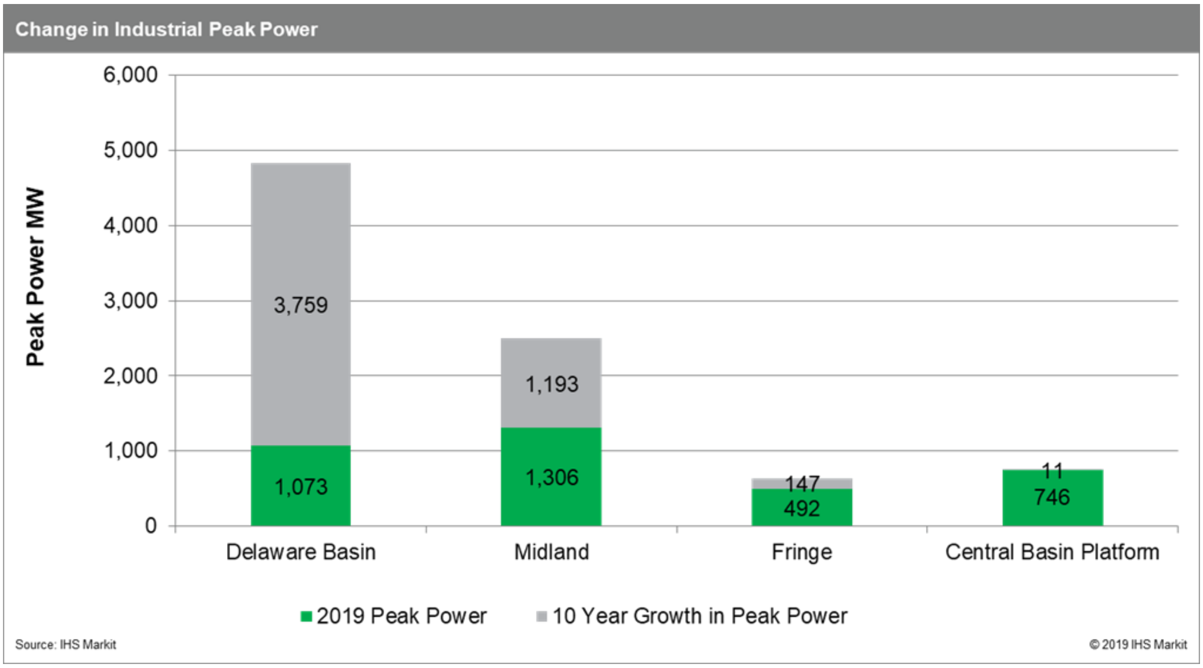


Figure 5-10. Change in industrial peak power from 2019 to 2030, by region

In order to supply these levels of peak power growth, an expansion of grid access beyond typical growth will be required. The current grid system will need to catch up to ongoing activities primarily in the Delaware region as the power markets of some of the Delaware Basin counties are the least served. Growth in the Delaware Basin area electrical infrastructure needs to outpace growth in the projected oil and gas activity power demand over the next several years, and our forecast indicates that at current rates of grid expansion, complete grid access for projected oil and gas activity demand will occur in late 2024. The grid infrastructure in the Midland and Fringe area counties has already met most of the current demand. Expansion in these areas will be limited to the growth in industrial activities. The Central Basin Platform already has adequate grid coverage given the current oil and gas activities. There may still be a need for grid expansion in some counties, as oil and gas operators discover new sources of oil and gas, but this is expected to be limited in the future.

3.6 One-mile Grid Map with Areas of Current and Future Focus

3.6.1 Introduction

In this section we analyze the expected increase in industrial power demand as it is projected onto a one-square mile grid (herein defined as block) that overlies a map of the Permian Basin. Here we will be able to see in detail areas where current grid usage is high and where it is most likely to increase over the next 10 years. This process is designed to identify future needs for additional infrastructure in a more detailed, localized way. We will discuss key drivers that are likely to drive the location of future development, display projected power demand in two-year increments and where we see increases over current power usage from current rates through, 2022, 2026 and 2030.

3.6.2 Methodology

GIS tools provided the means whereby this analysis could take place. To create the one-mile grid, we employed the following steps:

1. Created a grid by grouping and merging information pertaining to all horizontal wells (bottom-hole locations) which pertained to each block in the grid. This included average well performance, total cumulative production, total footage drilled, well quality (measured on a scale of 1-5) and well counts.
2. Determined the play assignments of each block by identifying play boundaries, namely the Bone Spring, Spraberry and Wolfcamp plays in the Delaware and Midland Basin, as well as horizontal wells being drilled in legacy conventional plays. Note that some blocks fell within the boundaries of two or more plays, while a large number were located outside all play boundaries
3. Used assumptions pertaining to stacking and spacing to determine the total potential number of well locations that could be drilled in each block, and then subtracted the current location totals in each block from the potential locations in order to obtain the number of remaining locations
4. In conjunction with these location counts in each block we combined the resource quality to assess the current and potential resource in each block and the quality or concentration of that resource. Our assumption is that operators are going to develop better resources first, before developing poorer quality acreage. Using these values and determinations we developed a potential amount of resource that could be developed by 2030.
5. Combined gathering miles in each block with the resource quality and well count to calculate a total factor for each block that was related directly to current and future power usage
6. Grouped or assigned each block to one of the specific 24 counties analyzed in this study and calibrated our models so that the combined block totals in each county would add up to the total of that county. We did this by calibrating all individual block factors (which were calculated by combining resource quality, remaining well count and gathering miles) to the *forecasted county level oil and gas activity demand* for each given year in order to obtain a power usage value for each block.

    Note that for the purpose of this portion of the study forecasted county-level oil and gas activity demand refers to that power required to perform all upstream activities and mid-stream gathering and oil transport *only*. This excludes forecasted power requirements for gas processing and refining, since these activities are either location specific for current or planned processing plants, or we do not know where new ones would be located, even when demonstrating a specific need within a given area or region.

7. This means that the power usage within each block for years 2020, 2022, 2024, 2026, 2028 and 2030 would have to add up to the total for each county, which in turn would have to add up to the total forecasted power demand.

Figure 6-1 provides the correlations between values use in August of each respective year between the Oil and Gas Electricity without Processing and Refinery (MW), which was used to formulate the power distributions shown on the map, and other key comparisons. Within the descriptions of each map, reference is made to yearly values displayed on the graph and highlighted values shown in the corresponding data table.

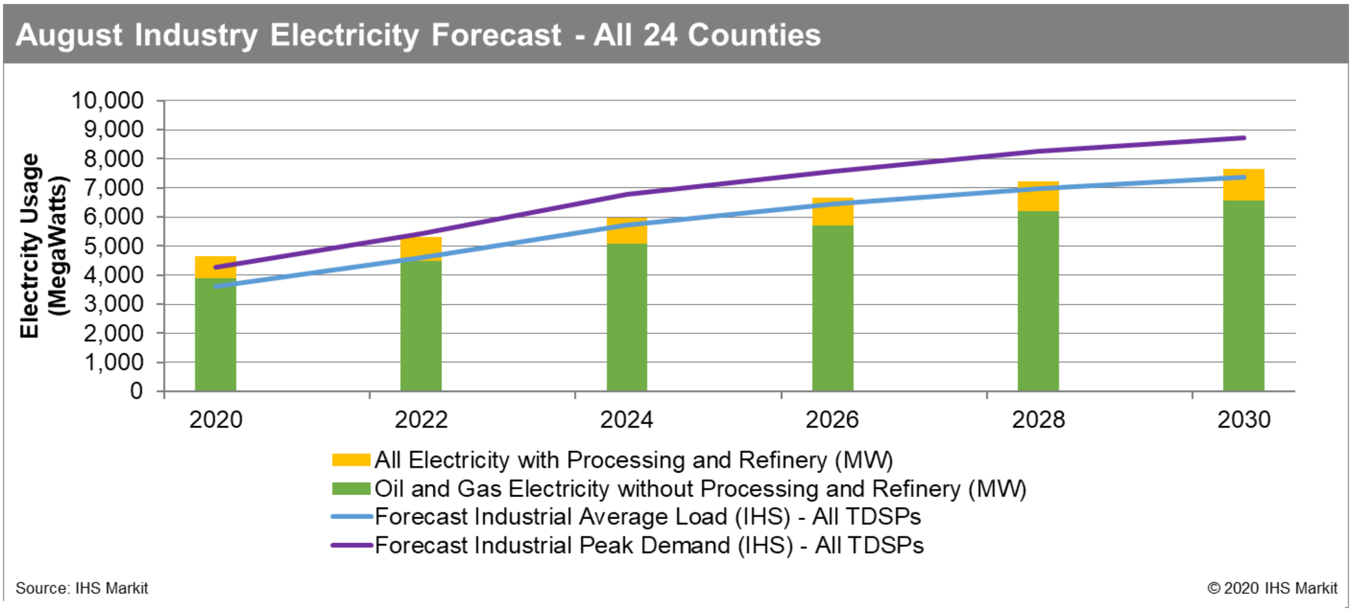


Figure 6-1: August Industry Electricity Forecast for All 24 Counties

Date	Oil and Gas Electricity without Processing and Refinery (MW)	Processing and Refinery (MW)	Total Oil and Gas Electricity Usage (MW)	Forecast Industrial Average Load (IHS) - All TDSPs	Forecast Industrial Peak Demand (IHS) - All TDSPs
Aug-2020	3,888	767	4,654	3,616	4,275
Aug-2022	4,488	826	5,314	4,592	5,429
Aug-2024	5,093	891	5,984	5,730	6,775
Aug-2026	5,709	949	6,658	6,458	7,571
Aug-2028	6,199	1,007	7,206	6,990	8,264
Aug-2030	6,576	1,065	7,640	7,380	8,725

Table 6-1: August Industry Electricity Forecast for All 24 Counties

Figure 6-1 and Table 6-1 show the comparison between total electricity usage of oil and gas activity with/without processing and refinery to the TDSP-served current forecast industrial average load and peak demand. Summing the total for each county sums up to the total forecasted power demand.

Set forth below are the map images used to create the analysis and the results of succeeding years:

3.6.3 Drivers of Power Demand

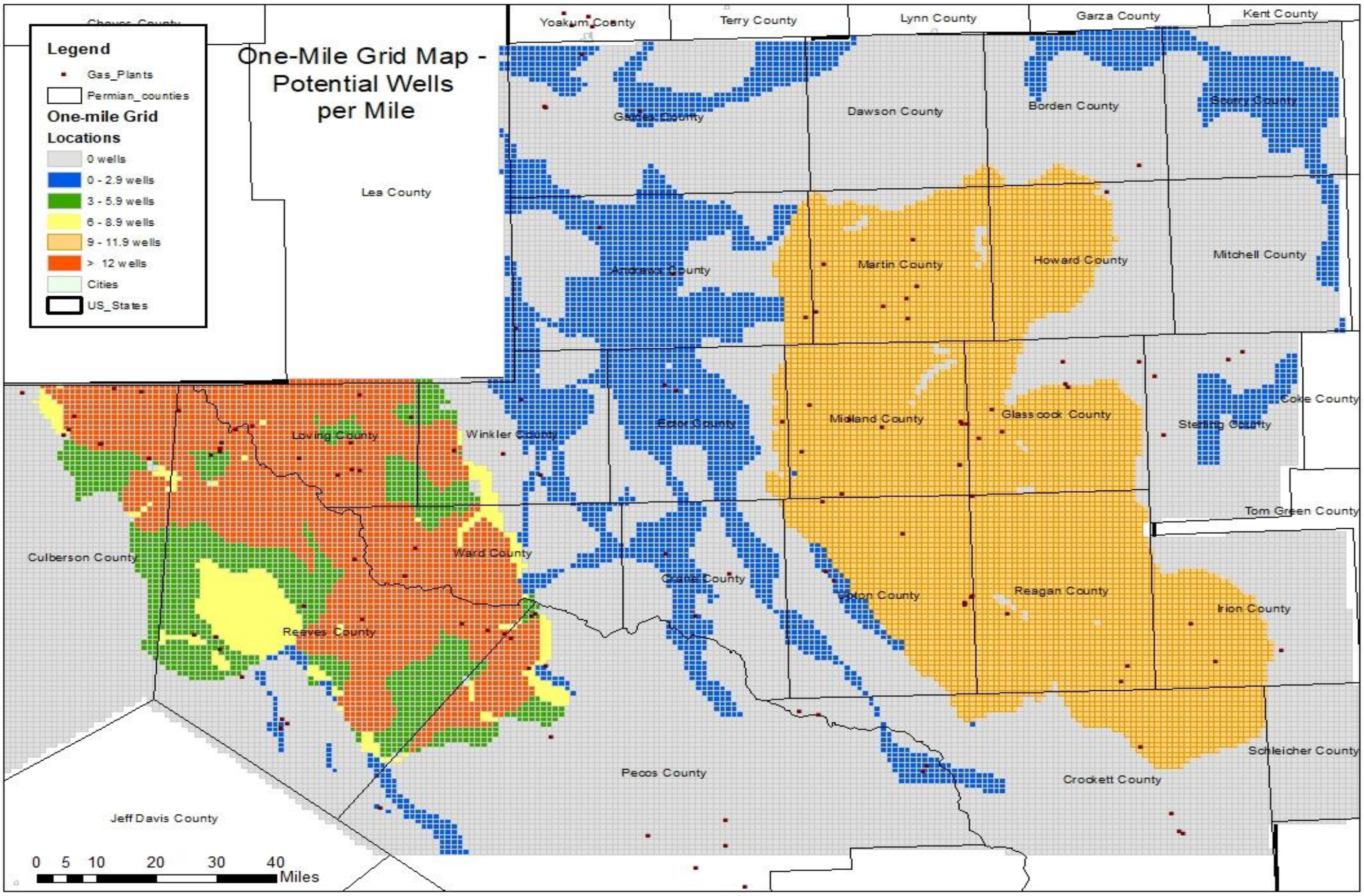


Figure 6-2: One mile grids with potential stacked horizontal well locations per square mile

Figure 6-2 Illustrates potential drilling locations within each block. Horizontal wells have become dominant in the Permian, with over 35,000 potential locations identified. Warmer colors show areas of greater concentration, in terms of one-mile squares. The greatest levels of horizontal well activity have occurred in the Delaware and Midland Basins. The potential wells per block are greater in the Delaware Basin than Midland Basin because there are two plays in the Delaware (Bone Spring and Wolfcamp) with an assumed average of seven stacked reservoirs in these combined plays. On the other hand, we have assumed an average of 5 stacked locations in the Wolfcamp of the Midland Basin. The blue areas typically outline boundaries of conventional plays with horizontal drilling which are less attractive and where we have assumed just one stacked reservoir. We have adjusted these well counts shown on the map to reflect projected lateral lengths (which are longer than the one-mile grid length) and an assumed well spacing of 4 wells per section (side by side in a single block). This means that we expect to see areas where 9 to 12 wells are drilled in a single block.

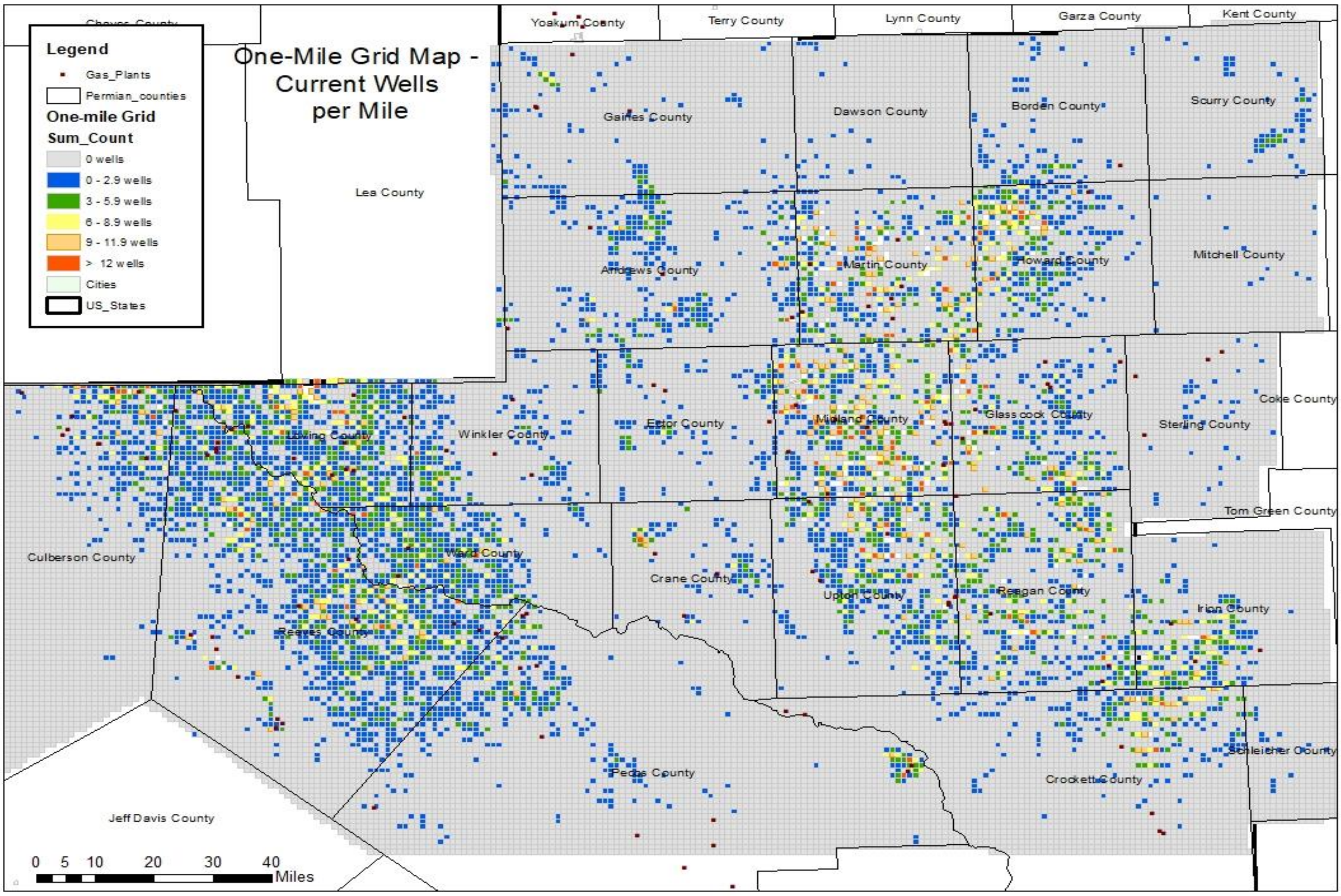


Figure 6-3: One mile grids with current stacked and concentrated horizontal well locations per square mile

Figure 6-3 illustrates locations within each block that have already been drilled. Generally, most blocks have less than 6 wells drilled in each with a few containing more. The Midland Basin concentrations as shown by the preponderance of yellow blocks appears to be somewhat more developed.

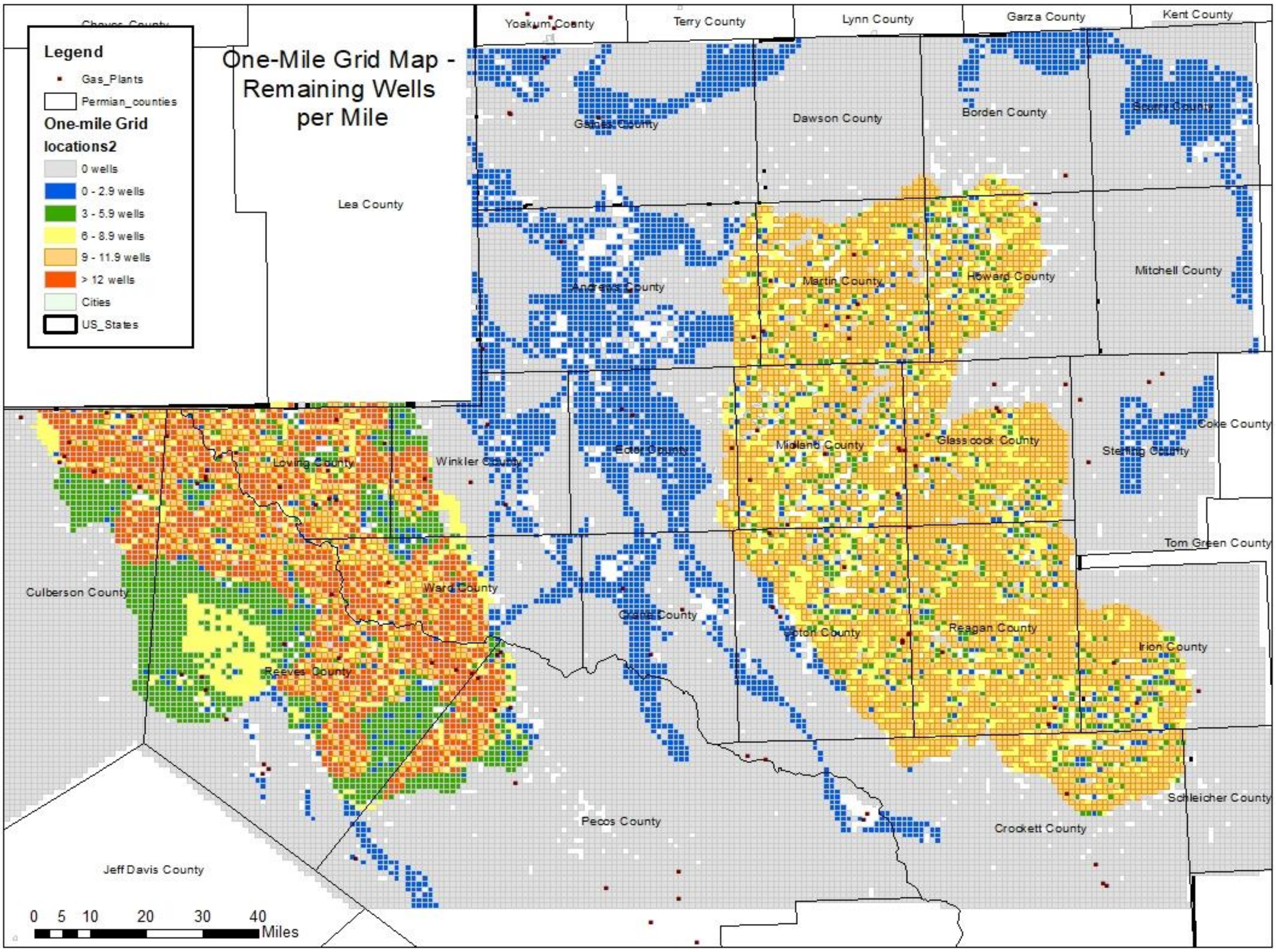


Figure 6-4: One mile grids with remaining stacked and concentrated horizontal well locations per square mile

Figure 6-4 illustrates potential remaining drilling locations within each block. These values were obtained by subtracting the total wells drilled in each block from the potential wells drilled in each block. Note that there are still many blocks that are yet undrilled but are located in the play fairways and where we expect development to occur.

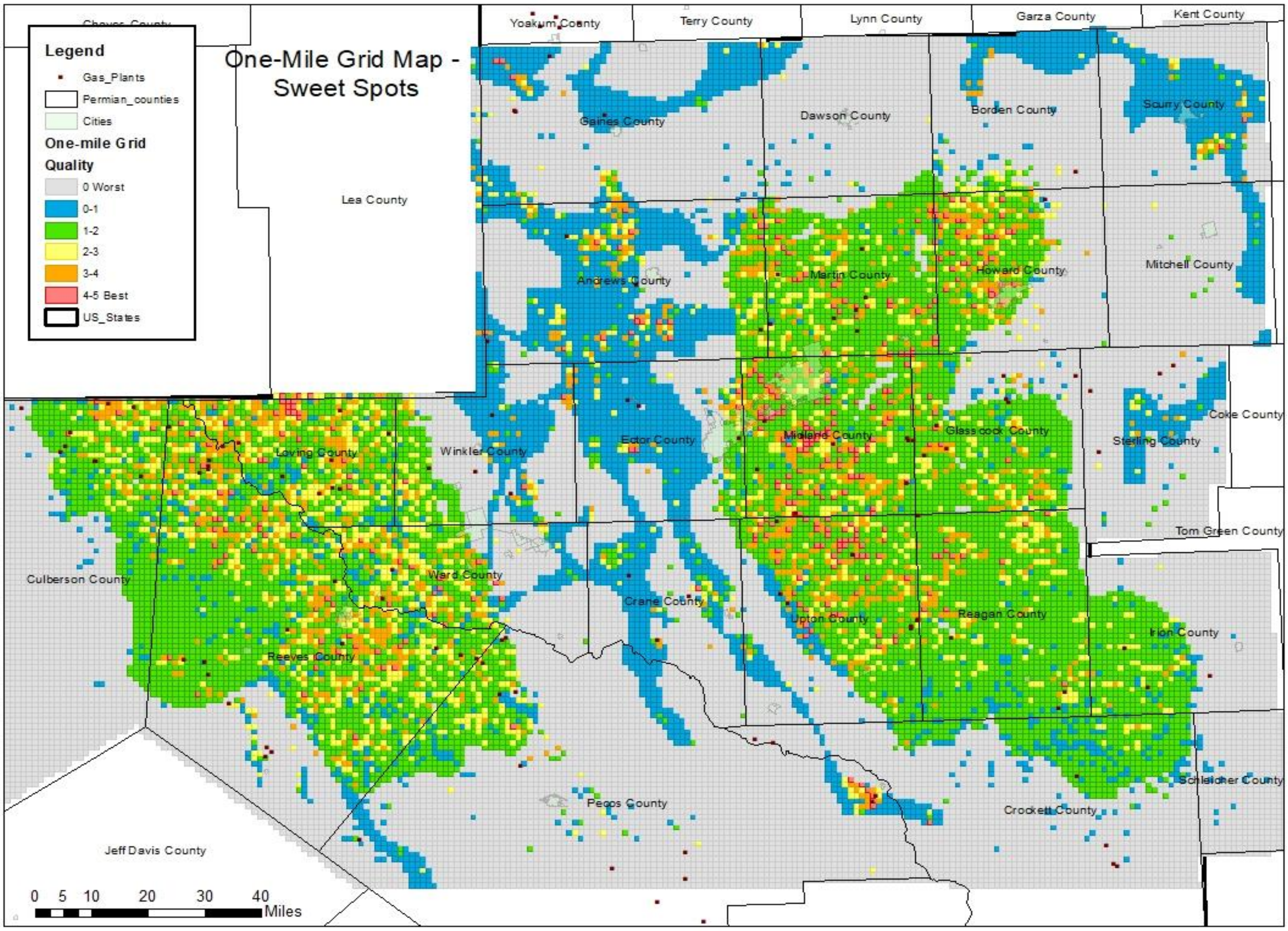


Figure 6-5: One mile grids with average well quality

Figure 6-5 illustrates the quality of each block. IHS Markit tracks the performance of wells. Based on this well performance, IHS Markit ranks acreage into five quality categories. On the map, 0 shows areas that are not generally prospective (in gray), while 4-5 are rated the best (in red). Historical well performance drives these ratings with the best wells indicating the best rated acreage. The best acreage is often referred to as the sweet spot or core of the play. Operators are more likely to drill in these “sweet spots” shown in warmer colors in the future and will develop them first. The blue areas are signifying more conventional activity with higher water-oil ratios than unconventional wells, which will result in higher power demand for water production and disposal.

Current power demand will tend to be focused in the yellow to red blocks, but in the future will migrate to the green blocks as these somewhat less prospective areas get developed.

3.6.4 Forecasted power demand by block

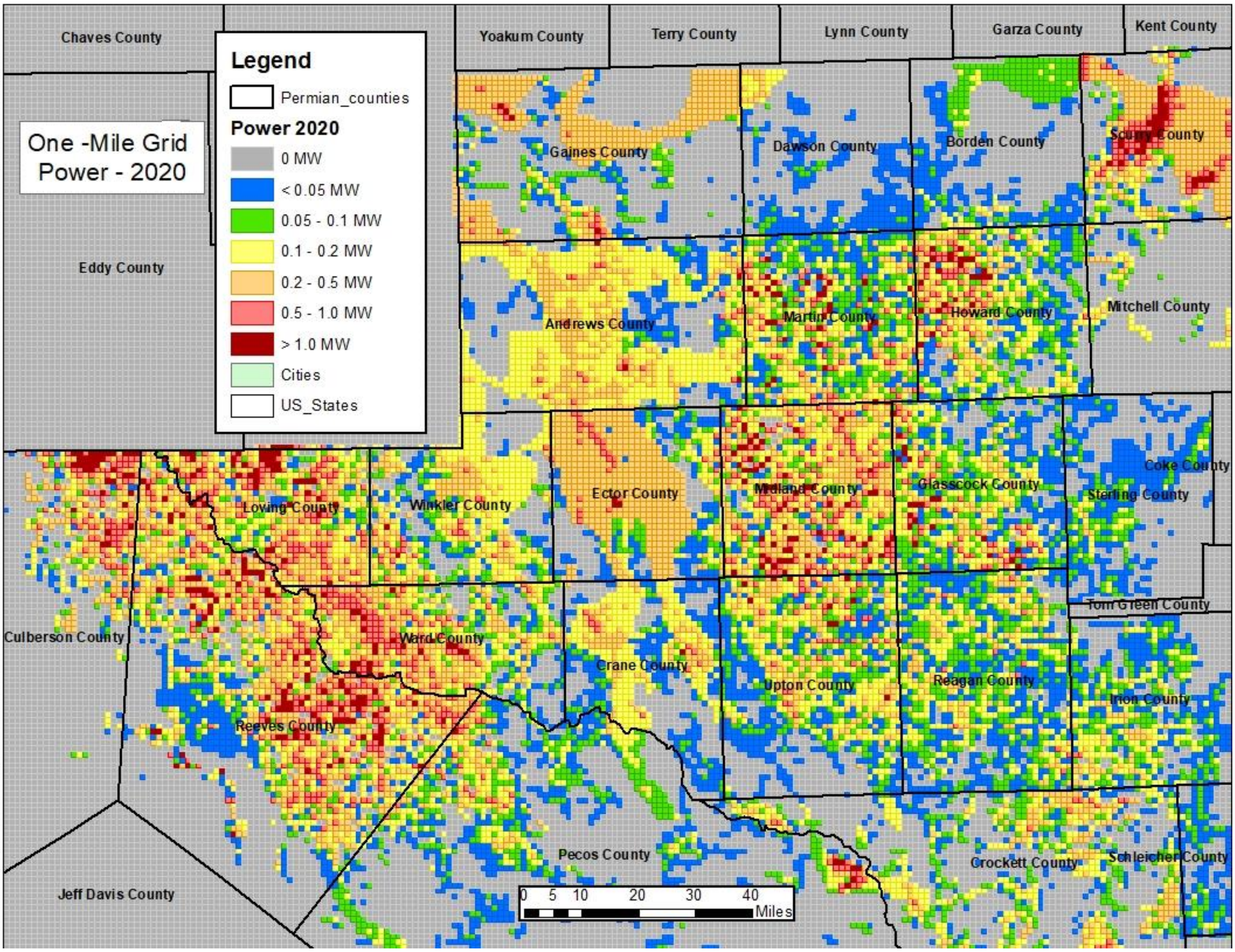


Figure 6-6: One mile grids with current power demand (MW) for each grid square

Figure 6-6 illustrates current power demand within each block. Power demand in 2020 is expected to be concentrated in the unconventional areas of the Delaware and Midland. There are some scattered pockets of high demand, even in conventional areas where oil field production is still occurring. The total power demand for oil and gas activities (without processing and refining) for 2020 is projected to be 3,888 MW, which is scattered throughout the basin in various concentrations as you see on the map. This compares with a total August 2020 industrial power demand of 4,654 MW with forecasted peak demand of 4,275 MW (note that for this year the total demand that can be supplied by TDSPs is lower than the industrial demand).

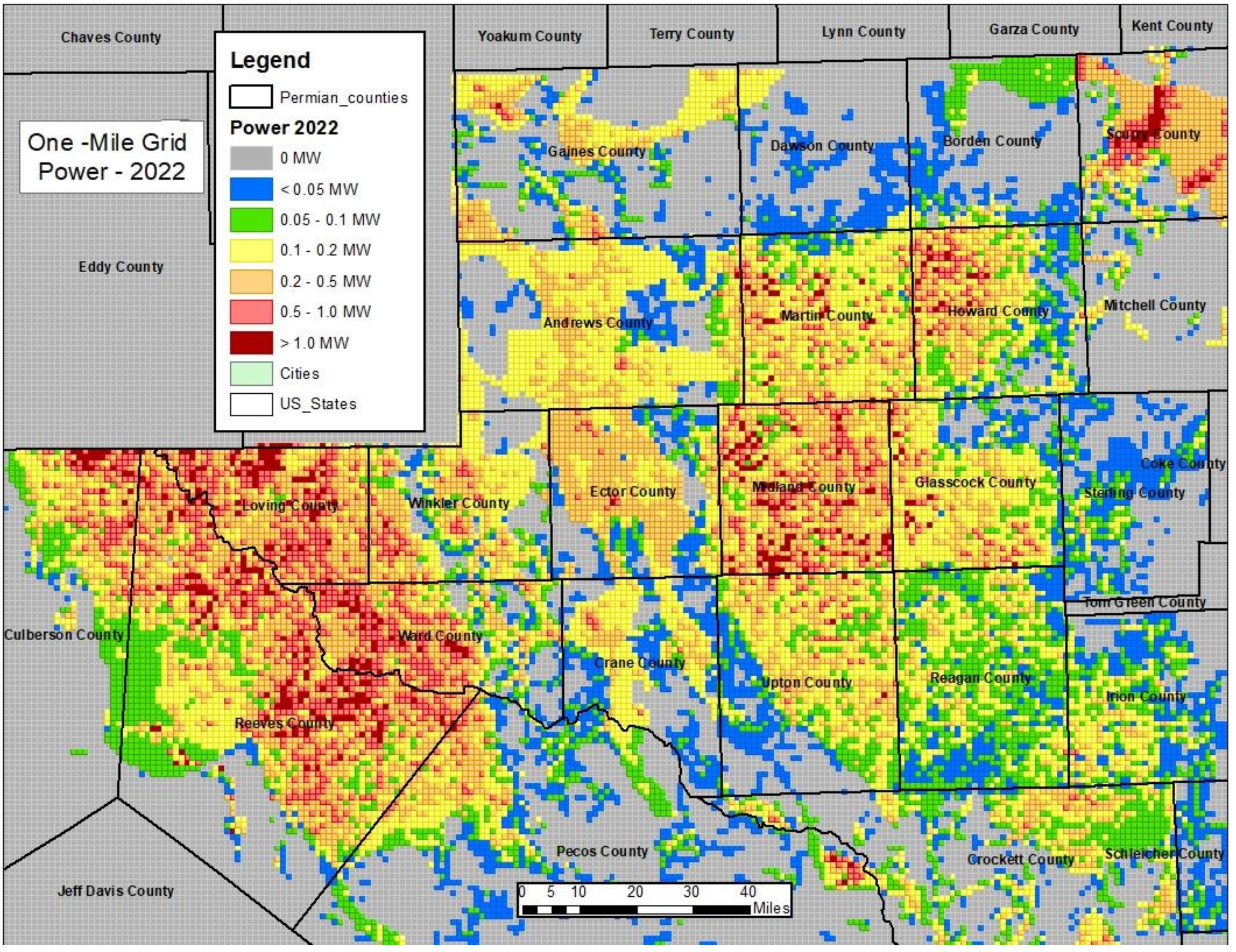


Figure 6-7: One mile grids with forecasted power demand (MW) in 2022 for each grid square

Figure 6-7 illustrates power demand within each block in 2022. By 2022, greater power demands are more widespread in the areas with more unconventional activity. Many of the blocks in the Delaware and Midland Basins are expected to require over 1 MW. Scattered pockets of high demand, even in conventional areas persist. The total power demand for oil and gas activities (without processing and refining) for 2022 is projected to be 4,488 MW, which is scattered throughout the basin in various concentrations as you see on the map. This compares with a total August 2022 industrial power demand of 5,314 MW with forecasted peak demand of 5,429 MW.

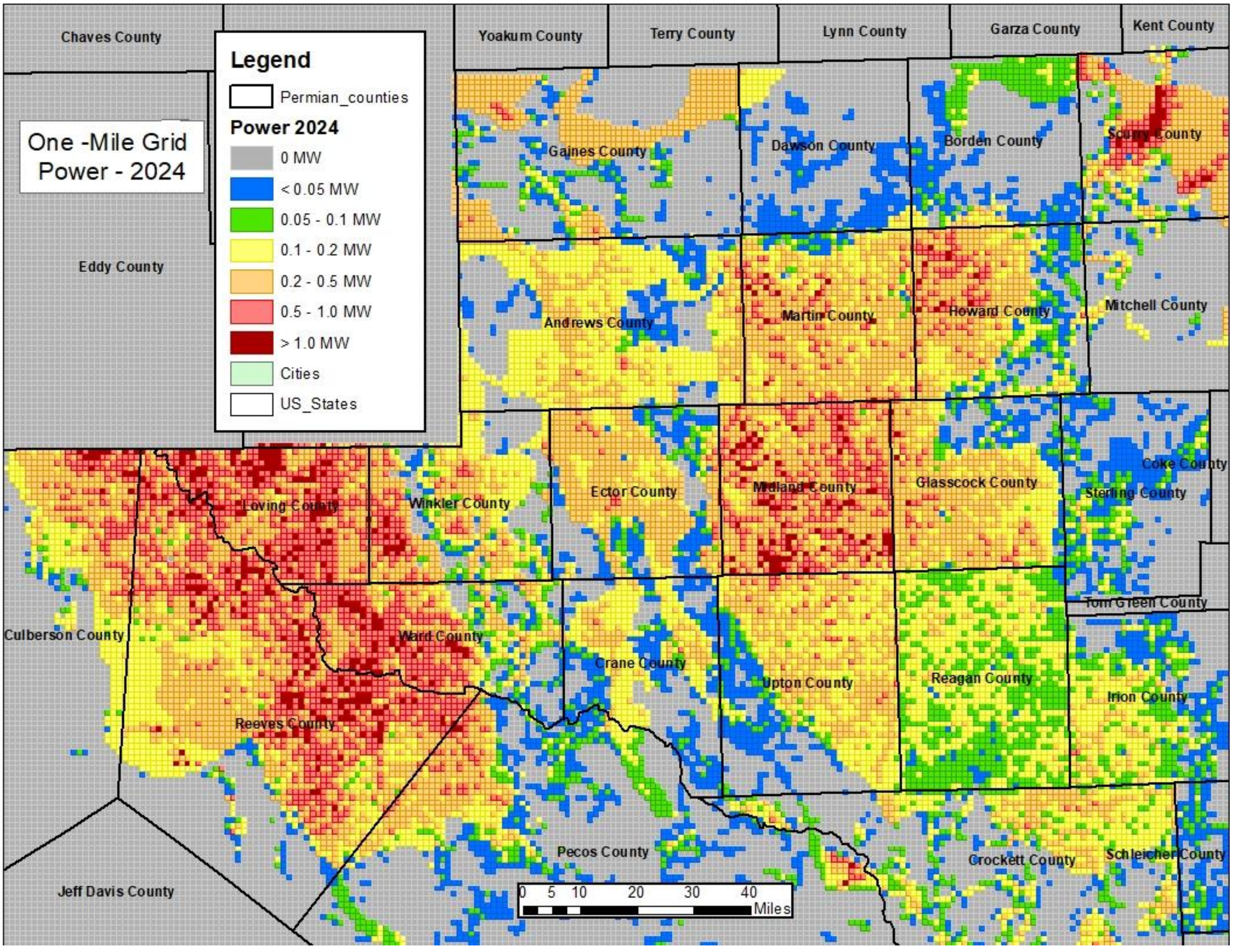


Figure 6-8: One mile grids with forecasted power demand (MW) in 2024 for each grid square

Figure 6-8 illustrates power demand within each block in 2024**.** By 2024, greater power demands are more widespread in the Delaware Basin, with power demand being concentrated in Midland County of the Midland Basin where production is expected to grow rapidly during this period. This will spill over into the east end of Ector County where the trend continues. The total power demand for oil and gas activities (without processing and refining) for 2024 is projected to be 5,093 MW, which is scattered throughout the basin in various concentrations as you see on the map. This compares with a total August 2024 industrial power demand of 5,984 MW with forecasted peak demand of 6,775 MW.

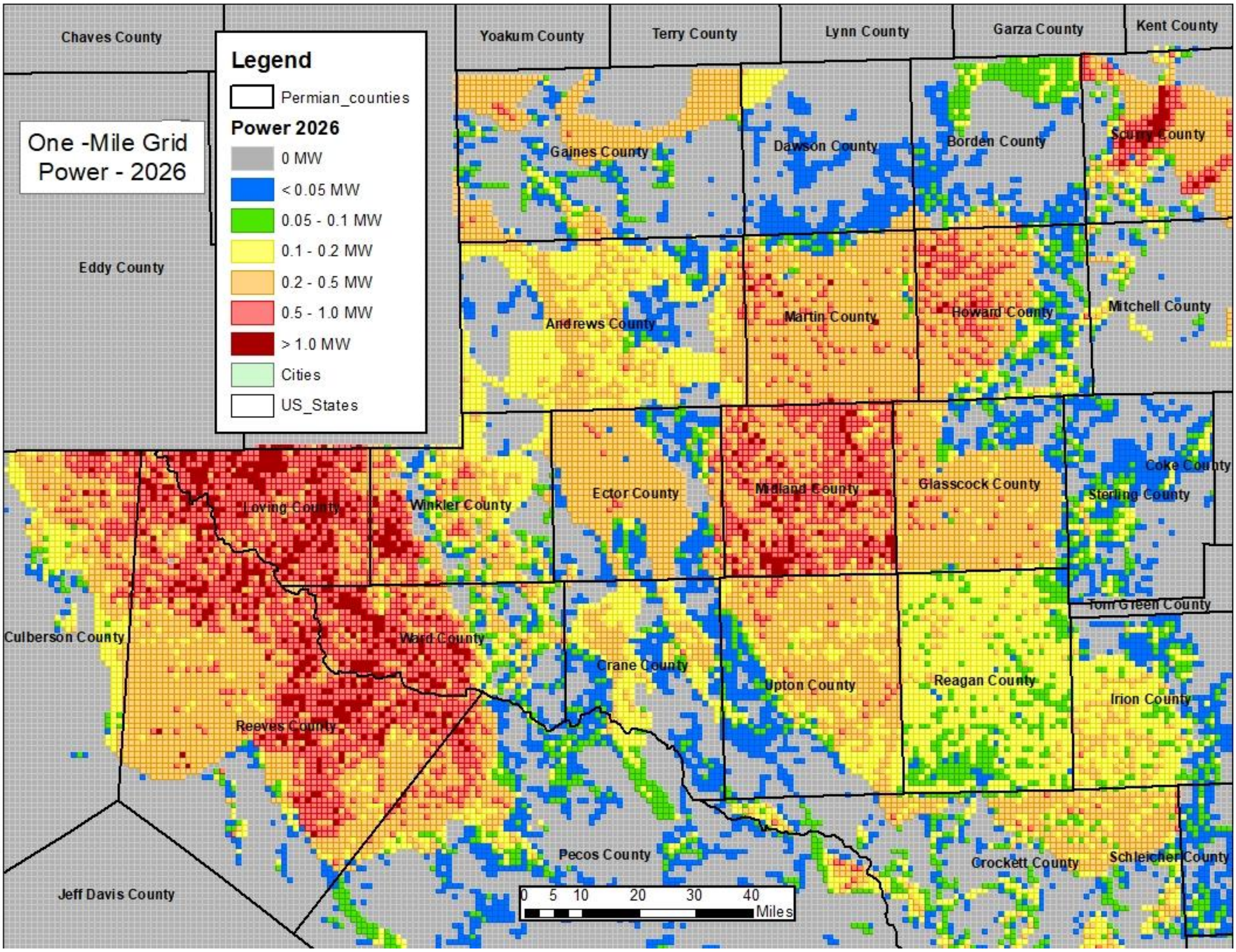


Figure 6-9: One mile grids with forecasted power demand (MW) in 2026 for each grid square

Figure 6-9 illustrates power demand within each block in 2026. By that year, greater power demands are more widespread in the Delaware Basin with some areas, such as Winkler County, becoming more concentrated. Power demand continues to be concentrated in Midland and east Ector County where development is intense. The total power demand for oil and gas activities (without processing and refining) for this year is projected to be 5,709 MW, which is scattered throughout the basin in various concentrations as you see on the map. This compares with a total August 2026 industrial power demand of 6,658 MW with forecasted peak demand of 7,571 MW.

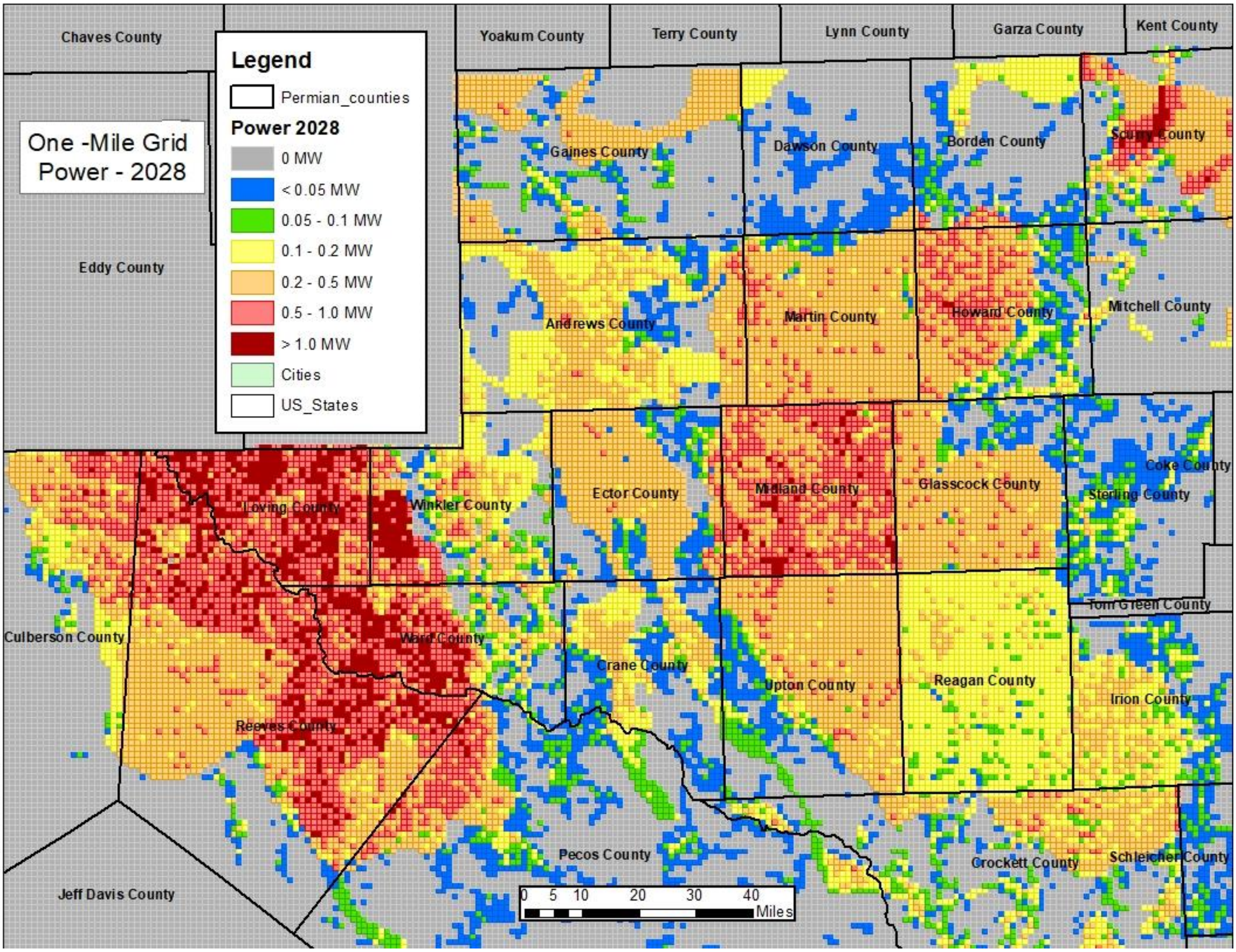


Figure 6-10: One mile grids with forecasted power demand (MW) in 2028 for each grid square

Figure 6-10 illustrates power demand within each block in 2028. By that year, greater power demands are found in similar locations as they were in 2026, but they are more intense. Howard County is beginning to emerge as a power demand center in the Midland Basin. The allocating of power to blocks by county power totals is apparent in the Midland Basin, as you see some counties with heavier concentrations of power than others. The total power demand for oil and gas activities (without processing and refining) for 2028 is projected to be 6,199 MW, which is scattered throughout the basin in various concentrations as you see on the map. This compares with a total August 2028 industrial power demand of 7,206 MW with forecasted peak demand of 8,264 MW.

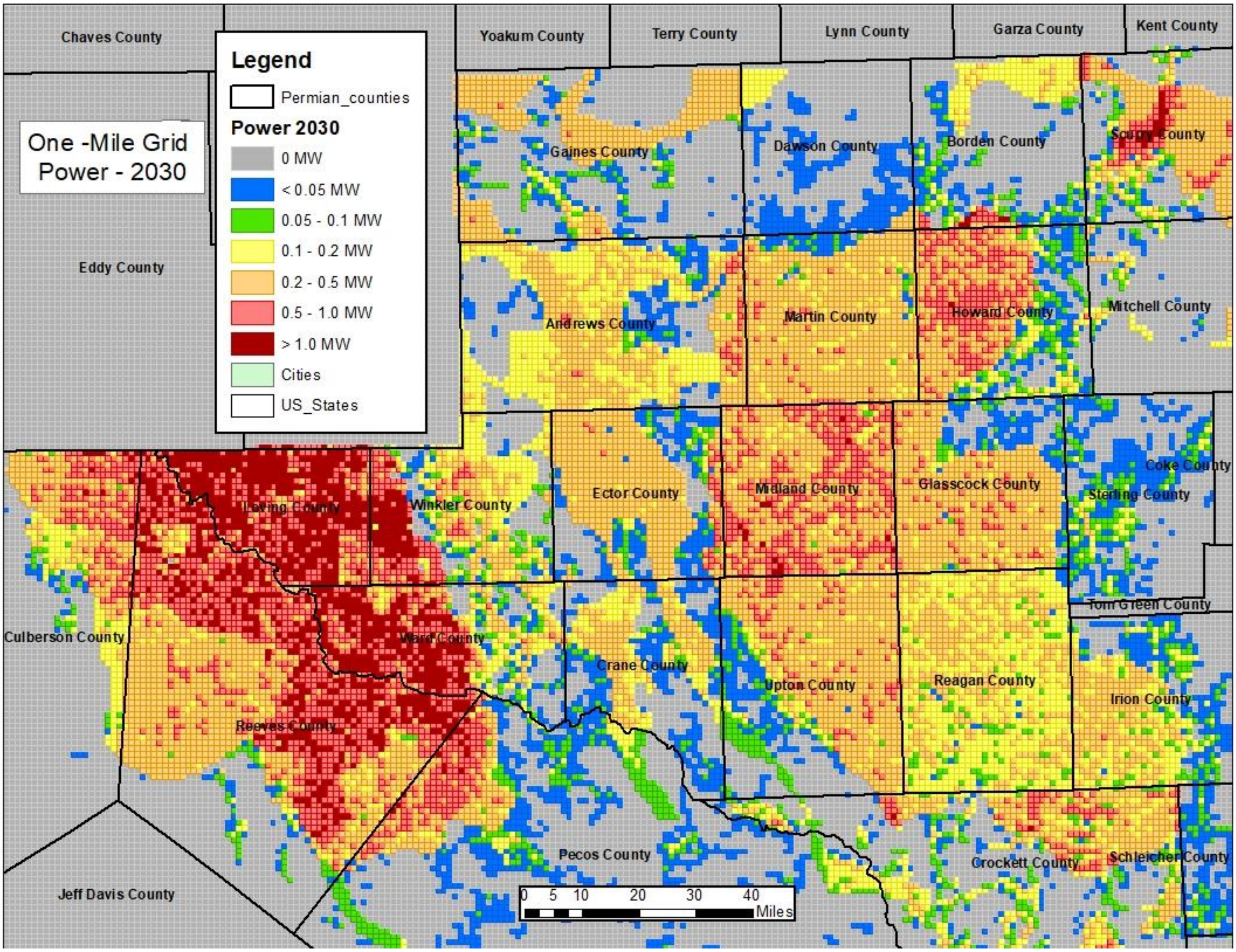


Figure 6-11: One mile grids with forecasted power demand (MW) in 2030 for each grid square

Figure 6-11 illustrates power demand within each block in 2030. By 2030, greater power demands are found in similar locations as they were in 2028 but they continue to intensify. In other words, the patterns and trends of 2028 are similar, but more concentrated. The allocating of power to blocks by county power totals is still apparent in the Midland Basin, although you are beginning to see some more concentrated development in Reagan County and less in Midland County as production declines in that county. The total power demand for oil and gas activities (without processing and refining) for this year is projected to be 6,576 MW, which is scattered throughout the basin in various concentrations as you see on the map. This compares with a total August 2030 industrial power demand of 7,640 MW with forecasted peak demand of 8,725 MW.

3.6.5 Relative Changes in Power from Current Levels

This analysis is a useful tool that can inform the power planning process, but not necessarily determine final outcomes. The analysis is based primarily on showing where oil and gas development is most likely to occur and to how intense that development will be. Other studies performed by IHS Markit suggest that the unconventional development within the Permian Basin unconventional plays is less than 20%, which suggests that a considerable amount of power requirement lie ahead and that the results of this analysis will assist in determining where that remaining 80% of development is likely to take place.

Figure 6-12 illustrates the change in power demand within each block from 2020 to 2022. From 2020 to 2022, much of the power increase is expected to be in the Delaware Basin (especially in western Winkler County). Midland County is expected to show the greatest increases in the Midland Basin. Certain conventional areas with increased water cut also are expected to increase somewhat, most notably Scurry County. Between 2020 and 2022, power demand is expected to increase by 872 MW (upstream, gathering and oil transport).

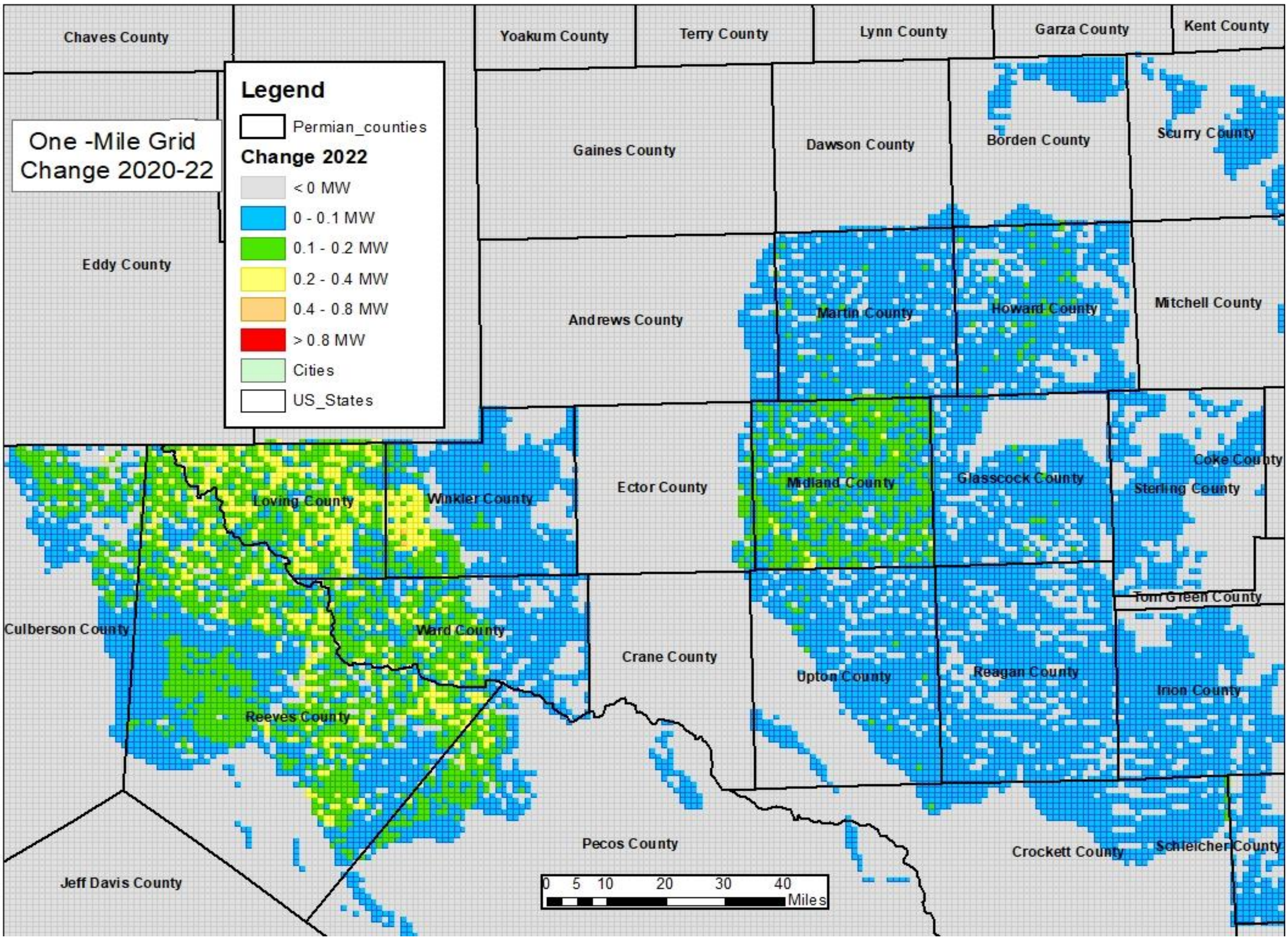


Figure 6-12: One-mile grids with forecasted change (generally increase in power demand (MW) from 2020 – 2022)

Figure 6-13 illustrates the change in power demand within each block from 2020 to 2026. From 2020 to 2026, the largest power increases are still expected to be in the Delaware Basin. Larger changes in the Midland Basin are expected in Martin and Glasscock Counties, rather than in Midland County. Certain conventional areas with increased water cut also are expected to increase, notably Scurry County. The concentrated changes in east Ector and Andrews counties are because of effects caused by the unconventional plays occupying a very small portion of these counties and the power increases attributable to these counties being concentrated primarily in these confined locations. Between 2020 and 2026, power demand is expected to increase by 2,226 MW (upstream, gathering and oil transport).

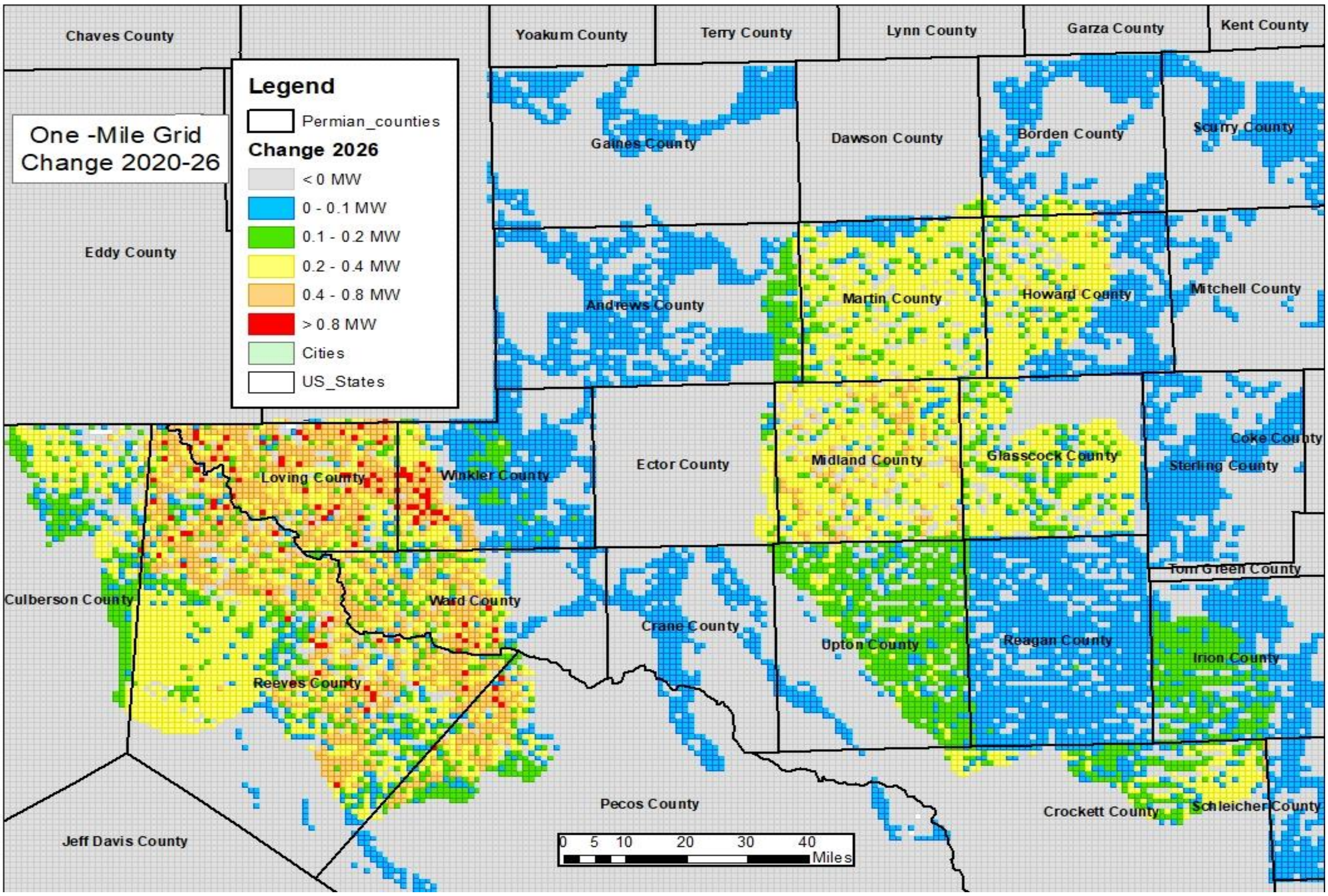


Figure 6-13: One-mile grids with forecasted change (generally increase in power demand (MW) from 2020 - 2026

Figure 6-14 illustrates the change in power demand within each block from 2020 to 2030. From 2020 to 2030, the largest power increases are expected to be in the Delaware Basin. Larger changes in the Midland Basin are expected in in Howard County with some meaningful increases are also expected in Upton County. The east Ector and Andrews county issue discussed earlier will also show up here as well. Between 2020 and 2030, power demand is expected to increase by 3,260 MW (upstream, gathering and oil transport).

To conclude Part 3, IHS Markit will recap the successful completion of the goals of this section, as IHS Markit has been able to (1) validate the calculated power usage against real historical data, (2) determine the extent to which oil and gas operations are on the electrical grid within each of the counties, (3) build a power demand forecast at the county level by applying these comparisons, (4) apply appropriate load factors to calculate peak coincidence, and (5) integrate these county-level power forecast with current and projected oil and gas activities, including projected drilling to identify areas where the highest likelihood of increased demand is likely to occur.

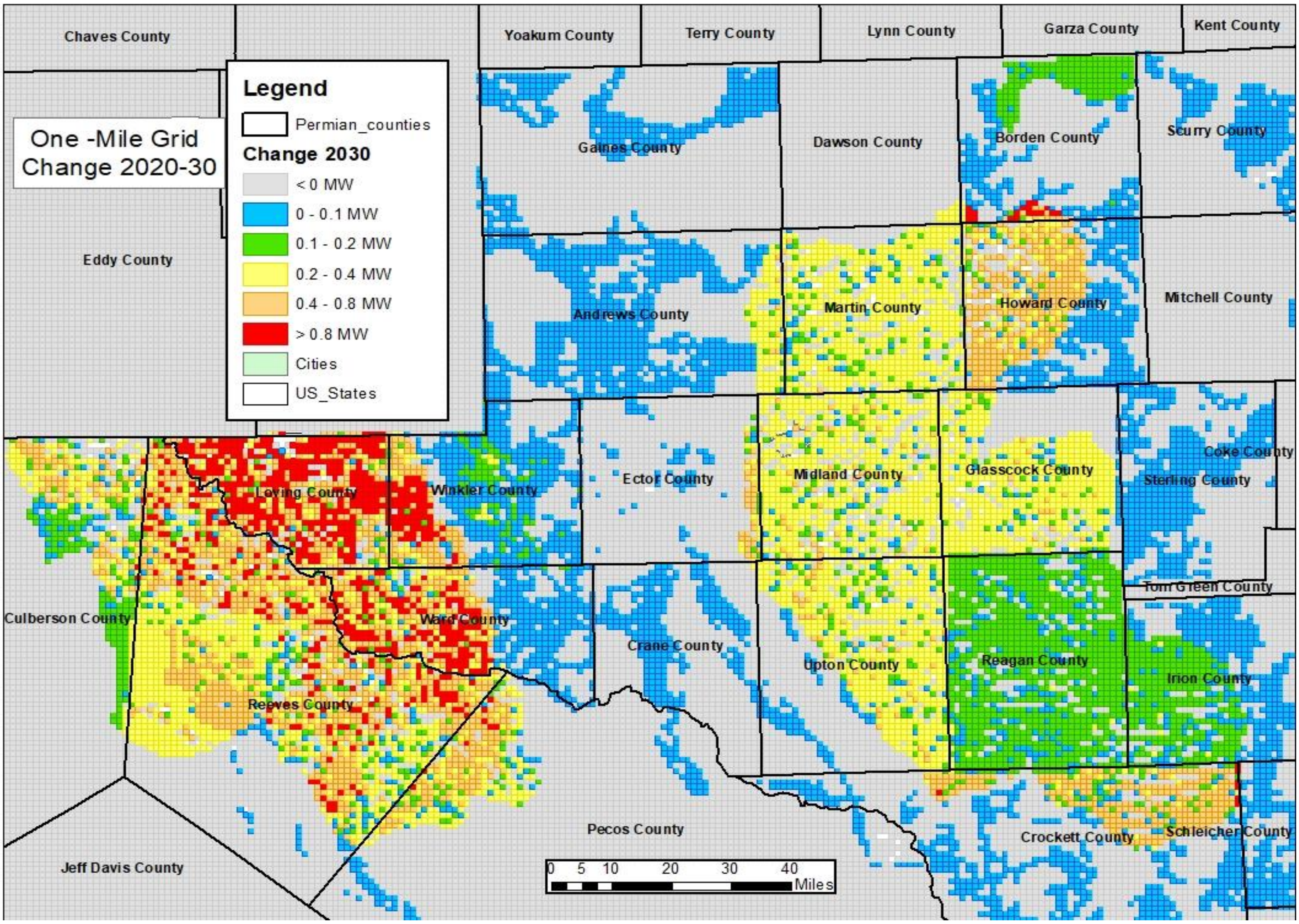


Figure 6-14: One-mile grids with forecasted change (generally increase in power demand (MW) from 2020 - 2030

4 Permian Basin Total Power Demand Forecast

4.1 Introduction

In the previous section, we progressed through the steps of analyzing and comparing historical oil and gas activity power demand with historical average power usage in order to lay the foundation for creating a forecast of future power demand. Furthermore, we determined a forecast for peak load. This was done solely for industrial load, and while industrial load will account for the vast majority of future load expectancy, we need to include residential and commercial load forecast in order to provide a complete picture of future load demand. In this part 4, we will provide a methodology and determine an outlook for future residential and commercial load and combine this outlook with the industrial load outlook to create a total load forecast. When creating this combined outlook, we will describe some adjustments needed in order to account for coincidence when combining the two outlooks. This combined outlook will be presented for each of the four regions and for the Permian Basin.

Findings

- The Delaware Basin's power demand is completely dominated by the industrial sector where oil and gas activity is expected to substantially increase. Growth is expected within the residential and commercial sectors, but it will constitute a small fraction of the power forecast in the Delaware Basin. Peak power for all sectors is expected to increase by 294% from 1,300 MW at the 2019 peak to 4,900 MW at the 2030 peak.

- The Midland Basin's power demand has a large contribution from residential and commercial activity, but the industrial sector accounts for the majority of the existing load. Since the growth rate in the industrial sector will be higher, the residential and commercial power will become a smaller percentage of the total load served over the next decade. Peak power for all sectors is expected to increase by over 56% from just over 2,040 MW at the 2019 peak to nearly 3,200 MW at the 2030 peak.

- The Central Basin Platform's power demand has a substantial contribution from residential and commercial activity much like the Midland Basin. However, residential and commercial power will become even more important over the next decade as the oil and gas activity stagnates in this region. Peak power for all sectors is expected to increase by 10% from 1,250 MW at the 2019 peak to just 1,370 MW by the 2030 peak.

- Power demand in the Fringe area of the Permian Basin currently has only a minor contribution from residential and commercial activity, which is expected to remain relatively constant throughout the study. Most of the Fringe area's growth will come from the industrial sector, but growth will be limited since oil and gas activity is not expected to ramp up much over the next decade. Peak power for all sectors is expected to increase by only 24% from 570 MW at the 2019 peak to 710 MW at the 2030 peak.

- Overall, the Permian region's power demand is dominated by the industrial sector where most of the growth is expected. Still, power demand is expected to grow in all sectors. Peak power for all sectors is expected to almost double from just under 5,200 MW at the 2019 peak to nearly 10,200 MW at the 2030 peak.

4.2 Residential and Commercial Power Demand

4.2.1 Input data

Residential and commercial power demand is expected to be a smaller component of the growth story in West Texas. IHS Markit obtained several data sets to feed into the residential and commercial demand forecast, which we approach as a granular econometric analysis. The input data sets are summarized in Table 2-1.

Data	Period	Frequency	Granularity	Source
Electricity usage billing data, with and without Sharyland, aggregated by county and customer type (Industrial, Commercial and Residential)	Jan 2010 - Dec 2019	Monthly	County level	Oncor
15-minute interval load data, aggregated by county and customer type (Industrial, Commercial and Residential)	Jan 2018 - Nov 2019	15-minute intervals	County level	Oncor
Oncor load serving ratio (estimated)	2019	Annual	County level	Oncor
Gross county product history and outlook	2010 - 2030	Annual	County level	Bureau of Economic Analysis (BEA) for history; IHS Markit for outlook
Average household income history and outlook	2010 - 2030	Annual	County level	Bureau of Economic Analysis (BEA) for history; IHS Markit for outlook
Household formation history and outlook	2010 - 2030	Annual	County level	Bureau of Economic Analysis (BEA) for history; IHS Markit for outlook
Residential and commercial electricity retail price history and estimated outlook	2010 - 2030	Annual	State level	Energy Information Administration (EIA) for history; IHS Markit for outlook
Heating degree days and cooling degree days	Jan 2010 – Nov 2019	Monthly	Metropolitan level	National Oceanic and Atmospheric Administration (NOAA)

Table 2-1: Input data sets to the residential and commercial power demand analysis

We aligned and compared the monthly electricity billing data with the 15-minute interval power data. Figures 2-1 and 2-2 provide examples of the comparison for Ector County for the residential and commercial sectors. In most counties, the two sets aligned well with some time lag because the billing data inherently contain a lag. An exact adjustment is not feasible as a practical matter because customers experience varied lags and the time resolution of the billing data is monthly. We made the simple adjustment to slide the billing data back one month (e.g., September billing data was assumed to apply to August). The observed alignment made us comfortable using the billing data for the econometric analysis on an annual basis and derive monthly load apportionments, and also comfortable using the 15-minute interval data for superimposing a load profile onto the results (e.g., calculating and applying monthly load factors to derive peak demand estimates). The 15-minute data do not require the time shift.

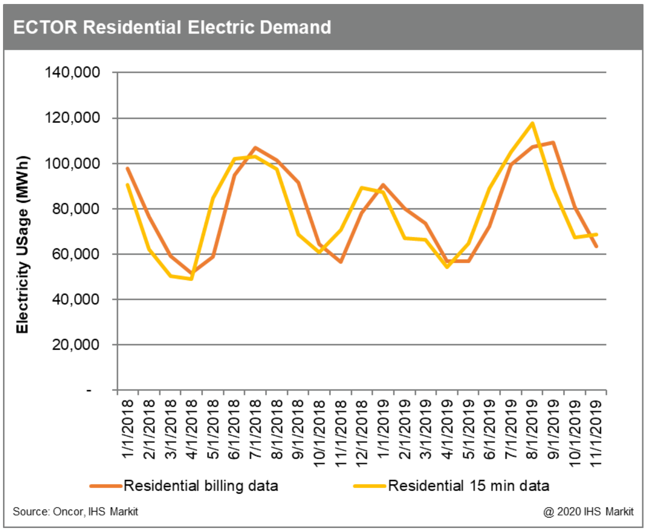


Figure 2-1 Comparison of billing data and 15-minute interval data for Ector County, residential sector

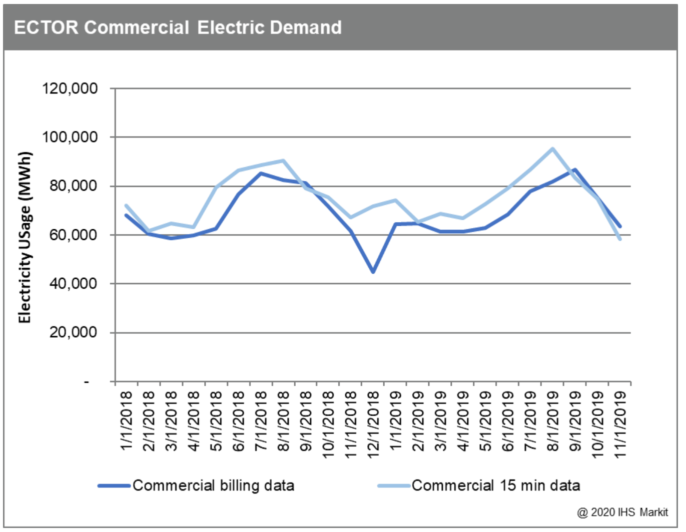


Figure 2-2 Comparison of billing data and 15-minute interval data for Ector County, commercial sector

4.2.1.1 Data challenges

IHS Markit encountered some challenges with the data we obtained. We adjusted and made estimations to clean up the data sets. These are important steps we took to gain confidence in the overall electricity demand forecasts:

- Sharyland adjustment: Oncor acquired Sharyland Utilities' retail distribution operations in late 2017. This transaction resulted in a large increase in electricity sales from 2018 onward in counties formerly served by Sharyland. These counties include Borden, Glasscock, Howard, Martin, Midland, Mitchell, Reagan, Sterling, and Upton. In order to derive a consistent history of demand, a scale-up analysis was performed in these counties to adjust the history of electricity sales before 2018 "as if" they included Sharyland. The analysis is informed by Oncor's provided electricity sales data (billing data) with and without the Sharyland acquisition. Sharyland's share of demand is inferred and applied to the history to scale up the historical demand. In cases (Borden and Sterling) where there are missing billing data without Sharyland, we assume that the increase in demand from 2017 to 2018 is largely due to Sharyland's acquisition. We then use this estimated ratio to adjust the history.

- Limited historical data set: Ten years (2010 to 2019) of electricity usage billing data are available for the residential and commercial demand forecast. We used these data to feed into our econometric analysis. To allow us to forecast peak demand, monthly load factors in each county for both sectors were calculated based upon 23 months (Jan 2018 – Nov 2019) of 15-minute interval power data. In some cases where there are missing power data (Borden and Irion) in 2018, only the most recent one-year history was used.

- Inconsistency in classification: We are comfortable with the overall alignment of the billing data and 15-minute interval data. However, there are some consumer class level mismatches in some counties. We adjusted the commercial sector load factors in these counties by apportioning out the average amount of load from industrial sector, thereby making the best estimate of commercial load factor that we could.

- Missing data: IHS Markit did not receive residential and commercial electricity billing data for Crockett and Schleicher counties since Oncor does not serve this area. Therefore, these two counties' residential and commercial demands are not forecasted. Load factors in the adjacent major counties are used as proxies.

- Several of the counties evaluated have small average loads (less than 4MW). To address this challenge, the adjacent major counties that are serving the load are used as a proxy in our analysis. We use the adjacent county's demand growth rate to approximate the demand growth rate in the county with small load. The small load proxies are summarized in Table 2-2.

Counties	Serving entity
Irion: small average load	Load served from Reagan County Substation.
Sterling: small average load	Load served from Reagan County Substation and small amount from Mitchell County Substation.
Gaines: small average load	Load served from Andrews County substation

Table 2-2: Use of proxy counties to address small average load counties

4.2.2 Methodology for residential energy and peak demand forecasts

We forecasted annual residential demand by county. The explanatory variables in our residential analysis are summarized in Table 2-3.

Explanatory variables	Note
Residential electricity sales price (res_price)	We use the IHS Markit November 2019 ERCOT wholesale power price forecast, with estimated conversion to a residential retail price. The growth rate (estimated at 1.8 percent) from 2019 to 2030 is then used to create a smooth trajectory of retail prices so that the longer-term retail price trend is captured in the econometric equations without distorting month-to-month patterns in power consumption in our forecast. Historical retail prices are taken from the US Energy Information Administration (EIA).
Average household income (ahi)	IHS Markit macroeconomics outlook for West Texas. Historical data taken from Bureau of Economic Analysis (BEA).
Household formation (HH)	
Cooling degree days/Heating degree days (CDD/HDD)	We use Midland metropolitan numbers from NOAA as history and 10-year average for the forecast. Our forecast assumes that the most recent 10-years of weather data are "weather normal."

Table 2-3: Explanatory variables in the residential electricity demand forecast

The following is the general econometric equation that we used in the residential sector:

$$\begin{aligned}\log(\text{res\_demand\_county}/\text{HH\_county}) \\ = \beta_1 \log(\text{res\_price}) + \beta_2 \log(\text{ahi\_county}) + \beta_3 \log(\text{CDD}) + \beta_4 \log(\text{HDD}) + \text{Constant}\end{aligned}$$

We add a time trend variable and a lag (1 year) left-hand side variable when the residuals are serially correlated to correct the regression (and restore the basic assumptions of linear regression). In the small load counties (Sterling, Gaines, and Irion as discussed above), we use the adjacent county's demand growth rate to approximate their demand growth rate.

After forecasting residential demand for each county using forecasts of the explanatory variables (and household formation, which appears on the left-hand side of our regression equation), we take the following additional steps:

- Disaggregate annual energy demand to monthly energy demand using the average monthly fraction inferred from the electricity billing data.
- Adjust the results for a 4% distribution loss factor for residential / commercial demand. This "grosses up" the sales-level data to the distribution substation level. Accordingly, we divide the monthly energy forecasts by 0.96.
- Convert monthly energy demand to annual peak demand by county: We use the 15-minute interval data to calculate residential load factors for each county in each month. The load factor is applied to the monthly energy

demand to obtain an estimate of monthly peak demands. The annual peak (for residential demand) is the maximum of the monthly peak demand estimates.

4.2.3 Methodology for commercial energy and peak demand forecasts

We forecasted annual commercial demand by regional grouping. The explanatory variables in our commercial analysis are summarized in Table 2-4.

Explanatory variables	**Note**
Commercial electricity sales price (com_price)	We use the IHS Markit November 2019 ERCOT wholesale power price forecast, with estimated conversion to a commercial retail price. The growth rate (estimated at 1.4 percent) from 2019 to 2030 is then used to create a smooth trajectory of retail prices so that the longer-term retail price trend is captured in the econometric equations without distorting month-to-month patterns in power consumption in our forecast. Historical retail prices are taken from the US Energy Information Administration (EIA).
Gross county product (GCP)	IHS Markit macroeconomics outlook for West Texas. Historical data taken from Bureau of Economic Analysis (BEA).
Cooling degree days (CDD)/Heating degree days (HDD)	We use Midland metropolitan numbers from NOAA as history and 10-year average for the forecast. Our forecast assumes that the most recent 10-years of weather data are "weather normal."

Table 2-4: Explanatory variables in the commercial electricity demand forecast

We have grouped the counties as shown in Table 2-5 These groupings are largely consistent with the groupings used for the industrial electricity demand forecasts.

Grouping Name	**Counties included**
Central Basin	Andrews, Crane, Ector, Gaines
Delaware Basin	Culberson, Loving, Pecos, Reeves, Ward, Winkler
Midland Basin and Fringe	Glasscock, Howard, Martin, Midland, Reagan, Upton, Borden, Dawson, Mitchell, Scurry, Sterling, Irion

Table 2-5: County groupings for commercial electricity demand forecast

The following is the general econometric equation that we used in the commercial sector:

$$\log(\text{com\_demand\_grouping}) = \beta_1 \log(\text{com\_price}) + \beta_2 \log(\text{GCP\_grouping}) + \beta_3 \log(\text{CDD}) + \beta_4 \log(\text{HDD}) + \text{Constant}$$

After forecasting commercial demand for each county using forecasts of the explanatory variables, we take the following additional steps:

- Apportioning the groupings' annual demand to county-level demand: The demand growth in a regional grouping is apportioned to each county based on the county's share of GCP growth. The only exception is in 2020, when the GCP growth is negative, regionally, and overall demand growth is also projected to be negative – in this case, the (small) demand growth rate for 2020 in the regional grouping is applied uniformly to all counties in the group. In the small load counties (Sterling, Gaines, and Irion), we use the adjacent counties' demand growth rate to approximate their demand growth.

- Disaggregating annual energy demand to monthly energy demand using the average monthly fraction inferred from the electricity billing data.
- Adjusting the results for a 4% distribution loss factor for residential / commercial demand. This "grosses up" the sales-level data to the distribution substation level. Accordingly, we divide the monthly energy forecasts by 0.96.

- Converting monthly energy demand to annual peak demand by county: We use the 15-minute interval data to calculate commercial load factors for each county in each month. The load factor is applied to the monthly energy demand to obtain an estimate of monthly peak demands. The annual peak (for commercial demand) is the maximum of the monthly peak demand estimates.

4.2.4 Econometrics Modeling

The IHS Markit Economics approach to state models represents a significant departure from most previous multi-regional modeling and forecasting efforts. Most other regional models are constructed as proportions of the United States. In the IHS Markit system, however, each area is modeled individually and then linked into a national system. Thus, our models do not forecast regional growth as simple proportions of U.S. totals, but focus on internal growth dynamics and state specific business cycle response. This approach is referred to as "top-down bottom-up." It contrasts sharply with pure share (top-down) models, and models that are not linked to a national macroeconomic model (bottom-up) and contains the best of both approaches.

Our basic objective is to project how regional activity varies, given an economic environment as laid out by IHS Markit Macroeconomic and Industry forecasts. Important regional issues are addressed using information about detailed industrial mix, inter-industry and interregional relationships, productivity and relative costs, and migration trends.

IHS Markit maintains separate models for 50 states and the District of Columbia. The state models have the following basic characteristics:

- Each state is modeled individually, with different model structures and concept coverage specified according to the characteristics of the state
- National policy is explicitly captured,

These models are econometrically estimated and contain about 250 or more equations each. Employment, wage rates, and GSP by NAICS sector, along with income by type of activity, are modeled in detail. Other concept coverage includes population and its components of change, housing starts, retail sales, and the consumer price index. The models have the ability to forecast income, wages, and GSP in nominal as well as real dollars. Because the models are econometric with a quarterly periodicity, they are able to capture the full business cycle behavior of the economy, including the timing and amplitude of the turning points.

Another general characteristic of the models is that they are policy sensitive — they respond to changes in tax rates, military spending, utility costs, etc. The policy simulation capability can be broadly classified into two types. First, the models can capture how a state economy responds to changes in the national economy resulting from national or international events or a policy change. The second type of simulation these models can perform efficiently is an analysis of state government policies.

These models are re-specified and re-estimated periodically to account for new/updated historical information.

4.2.4.1 Example of residential energy and peak demand forecasts – Ward County

We forecasted the residential electricity energy demand for Ward County at the annual level. The resulting annual energy usage forecast is shown in Figure 2-3, along with the relevant historical data.

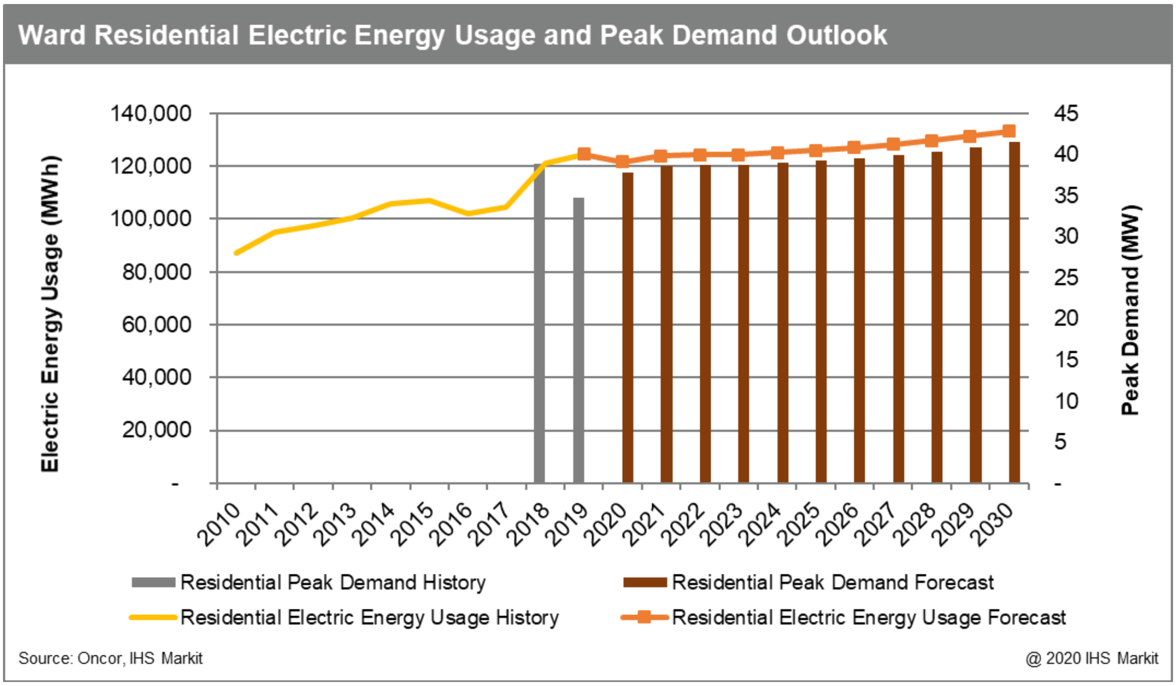


Figure 2-3: Annual energy (MWh) usage forecast for Ward County residential sector

We then adjusted the annual energy forecast for distribution losses to scale up to the distribution substation level (1/0.96).

Then, we apportioned the annual energy demand into the months based on the historical monthly shares of residential energy demand.

Month	Ward County, monthly apportionment of annual residential energy demand
Jan	9%
Feb	7%
Mar	6%
Apr	6%
May	8%
Jun	10%

Jul	12%
Aug	11%
Sep	9%
Oct	7%
Nov	7%
Dec	9%

Table 2-6: Ward County monthly apportionment of residential energy demand

Note: Numbers may not sum to 100% due to rounding.

We then converted the monthly energy to a monthly peak demand based on our calculated residential load factors.

Month	Ward county residential load factor
Jan	0.55
Feb	0.52
Mar	0.45
Apr	0.42
May	0.47
Jun	0.55
Jul	0.52
Aug	0.54
Sep	0.51
Oct	0.44
Nov	0.47
Dec	0.61

Table 2-7: Ward County residential load factors

Residential energy demand in Ward County is projected to grow 0.6% annually from 2019 to 2030. The peak demand is projected to grow 1.6% (annually) from 2019 to 2030. The peak demand growth rate is higher than the energy demand growth rate (over this period) because the 2019 peak demand was unusually low.

4.2.4.2 Example of commercial energy and peak demand forecast – Ector County

This commercial example is for Ector County, which is in our Central Basin Platform grouping. We forecasted the commercial electricity energy demand for the Central Basin Platform at the annual level. The resulting annual energy usage forecast is shown in Figure 2-4, along with the relevant historical data.

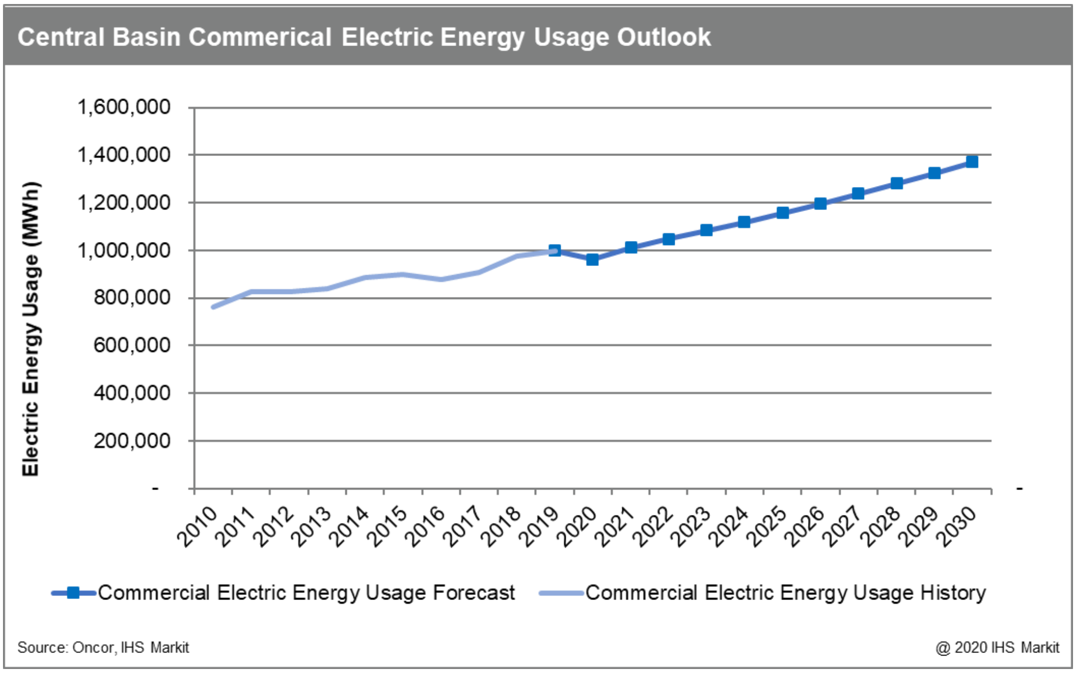


Figure 2-4: Annual energy (MWh) usage forecast for Central Basin Platform commercial sector

We then apportioned the regional grouping's demand growth to Ector County based on Ector's GCP growth relative to the GCP growth for the same grouping. We are sharing out the grouping's projected commercial electricity demand growth based on the GCP shares of growth for the grouping.

We then adjusted the annual energy forecast for distribution losses to scale up to the distribution substation level (1/0.96).

Then, we apportioned the annual energy demand into the months based on the historical monthly shares of commercial energy demand.

Month	Ector County, monthly apportionment of annual commercial energy demand
Jan	8%
Feb	7%
Mar	7%
Apr	8%
May	9%
Jun	10%
Jul	10%
Aug	10%
Sep	9%
Oct	8%
Nov	7%
Dec	8%

Table 2-8: Ector County monthly apportionment of commercial energy demand

Note: Numbers may not sum to 100% due to rounding.

We then converted monthly energy usage to monthly peak demand based on our calculated commercial sector load factors.

Month	Ector county commercial load factor
Jan	0.69
Feb	0.67
Mar	0.62
Apr	0.58
May	0.60
Jun	0.65
Jul	0.65
Aug	0.64
Sep	0.63
Oct	0.57
Nov	0.66
Dec	0.69

Table 2-8: Ector County commercial load factors

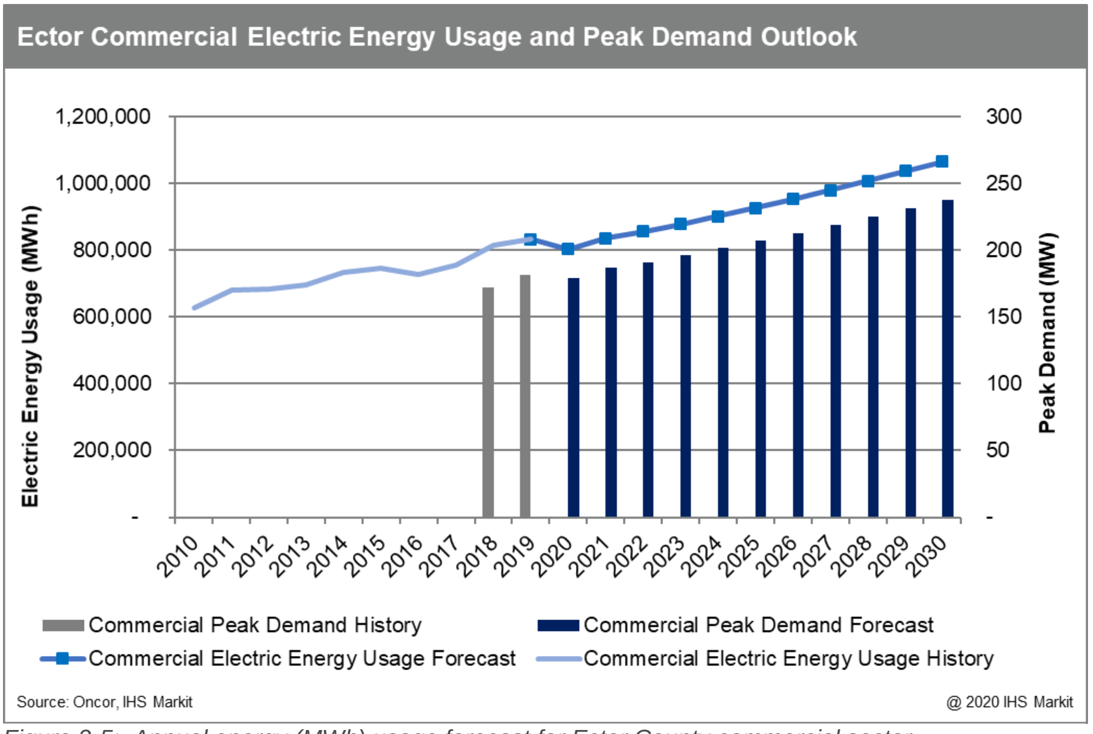


Figure 2-5: Annual energy (MWh) usage forecast for Ector County commercial sector

Commercial energy usage in Ector County is projected to grow 2.3% annually from 2019 to 2030. The peak demand is projected to grow 2.1% (annually) from 2019 to 2030.

4.2.5 Residential and Commercial Peak Demand Results

Applying the same methodology discussed above for Ward (residential) and Ector (commercial) counties, we forecasted the residential and commercial annual peak demands for all of the counties in this study. These are shown below.

Residential annual peak (MW)					
County	**2019**	**2020**	**2025**	**2030**	**CAGR 2019-2030**
ANDREWS	33	32	36	40	2.0%
CRANE	14	13	15	16	1.3%
ECTOR	278	263	299	335	1.7%
GAINES	<1	<1	<1	<1	5.5%
CULBERSON	<1	<1	<1	<1	-1.5%
LOVING	<1	<1	<1	1	8.1%
PECOS	14	15	14	15	1.0%
REEVES	1	1	1	1	4.4%
WARD	35	38	39	41	1.6%
WINKLER	4	4	5	5	2.2%
BORDEN	1	1	1	1	1.1%
DAWSON	25	25	26	27	0.7%
GLASSCOCK	7	7	7	8	1.5%
HOWARD	53	69	71	75	3.2%
MARTIN	11	11	11	9	-1.8%
MIDLAND	326	349	377	365	1.0%
MITCHELL	N/A	15	16	17	N/A
REAGAN	1	1	1	1	1.3%
SCURRY	N/A	25	26	29	N/A
UPTON	1	1	1	1	3.4%
IRION	<1	<1	<1	<1	2.0%
STERLING	<1	<1	<1	<1	-0.7%

Table 2-9: Annual residential peak demand by county

Commercial annual peak (MW)					
County	**2019**	**2020**	**2025**	**2030**	**CAGR 2019-2030**
Central Basin Group					
ANDREWS	28	27	42	56	6.5%
CRANE	15	14	17	21	3.3%
ECTOR	186	179	207	238	2.3%
GAINES	4	4	6	8	6.5%
Delaware Basin Group					
CULBERSON	6	6	6	6	0.0%
LOVING	9	9	17	27	9.9%
PECOS	46	44	45	46	-0.1%
REEVES	59	57	64	73	2.0%
WARD	49	47	48	51	0.5%
WINKLER	12	12	12	13	0.4%
Midland Basin + Fringe Group					
BORDEN	10	10	10	10	0.0%
DAWSON	20	19	19	19	-0.2%

GLASSCOCK	45	44	44	44	-0.1%
HOWARD	56	55	56	57	0.1%
MARTIN	64	62	68	71	1.0%
MIDLAND	265	259	267	268	0.1%
MITCHELL	9	9	9	9	-0.2%
REAGAN	17	17	18	19	1.1%
SCURRY	N/A	19	19	20	N/A
UPTON	13	13	15	16	1.7%
IRION	<1	<1	<1	<1	0.1%
STERLING	<1	<1	<1	<1	0.1%

Table 2-10: Annual commercial peak demand by county

Note: 2019 commercial annual peaks are from model results

4.3 Total Forecasted Peak Load

4.3.1 Combining the Residential-Commercial with the Industrial Forecast

In order to provide the full picture of peak power in the Permian counties, the monthly peak forecasts of the residential, commercial, and industrial peaks must be combined. However, these cannot be accurately added together without consideration of their coincidence factors.

Annually, each sector has its own power peak, which may occur in a summer month for residential and commercial or later in the year for industrial under high growth conditions. Monthly coincidence factors were calculated from the 15-minute interval data to describe the ratio between the overall coincident peak and the sum of the non-coincident peaks of the individual sectors. The 15-minute data used to develop the coincidence factors only considers loads supplied by Oncor.

4.3.2 Calculating the Inter-sector Coincidence Factor

The calculation of the coincidence factors includes:

- Examination of the county-level 15-minute data for the residential, commercial, and industrial sectors, individually and summed together
- For each month, finding the total (coincident) peak for all sectors in combination
- For each month, finding the peak for each sector (which can occur at different times) and sum these non-coincident peaks together
- Dividing the coincident peak by the sum of the non-coincident peaks
- For each month, taking the average of coincidence factors calculated from 2018 and 2019 15-minute data. The only exception is December, where only 2018 data is available.

Example: Calculation of Midland March coincidence factor

$$Peak_{total\_2018\_Mar} = Peak_{res\_2018\_Mar} + Peak_{com\_2018\_Mar} + Peak_{ind\_2018\_Mar}$$

$$= 124{,}043\ KW + 166{,}100\ KW + 202{,}922\ KW$$

$$= 493{,}065\ KW$$

$$Coincident\ Peak_{total\_2018\_Mar} = 450{,}131\ KW$$

$$Coincident\ Factor_{total\_2018\_Mar} = \frac{Coincident\ Peak_{total\_2018\_Mar}}{Peak_{total\_2018\_Mar}} = 0.91$$

Monthly coincidence factors ranged from 0.75 to 0.99. Overall, Reeves has the largest average coincidence factor (0.98) and Ector has the smallest (0.92).

4.3.3 Forecasting All Power

Despite not having data from all energy providers in all counties, the power forecasted by IHS in each sector considers the power supplied from all TDSPs (Transmission and Distribution Service Provider). Oncor power data for the residential and commercial peak demands had to be adjusted in the same way the industrial average load data was adjusted to account for all power. The total power for all sectors calculated from the Oncor data was divided by the estimated portion of coverage Oncor supplied in a county. The scaling up to consider all TDSPs was applied throughout the forecast.

The resulting sequence of 12 monthly coincidence factors describing January to December were multiplied with the sum of the peaks from each sector resulting in a total peak forecast by county. In order to roll up the counties into a single lump for the entire Permian or for areas of the Permian, the arithmetic average of the monthly coincidence factors of each component county was applied. This does imply perfect coincidence between counties, which is unlikely, but zero diversity has been assumed for the sake of the study. Inter-county coincidence factors have not been calculated.

For the following counties, no residential or commercial data was available: Crockett and Schleicher. Their residential and commercial contribution to the total peak was excluded, and their inter-sector coincidence factor was not calculated. In summary charts with more than one county, the average coincidence factor is the arithmetic average of the counties that did have coincidence factors calculated. This means the forecast summaries for the Midland Basin and Fringe areas will be under the actual power demand.

The graph below has four elements which account for the sector peaks, their coincidence factor and the resulting coincidence peak.

The four elements on the graph are as follows:

- **Commercial+Residential Peak Monthly (MW):** In green, this shows the peak power usage (non-coincident) from the commercial and residential sectors when analyzing them separate from the industrial. There is a high degree of seasonality, with much higher loads in the summer, especially due to demand from air conditioning. The green depicts the non-coincident sum of commercial and residential peak demand, although it must be noted these sectors in fact tend to be highly coincident.

- **Industrial Peak Monthly (MW):** In red, this shows the peak power usage, in isolation, from the industrial sector

- **Coincidence Factor of Residential, Commercial, and Industrial Peak:** A yellow line, a value less than 1.0 that shows the relationship between commercial+residential+industrial peak demand additivity. Historical relationships are assumed to continue in the future, so this line shows a regular pattern through 2030 for each county. The determined annual pattern is repeated through 2030.

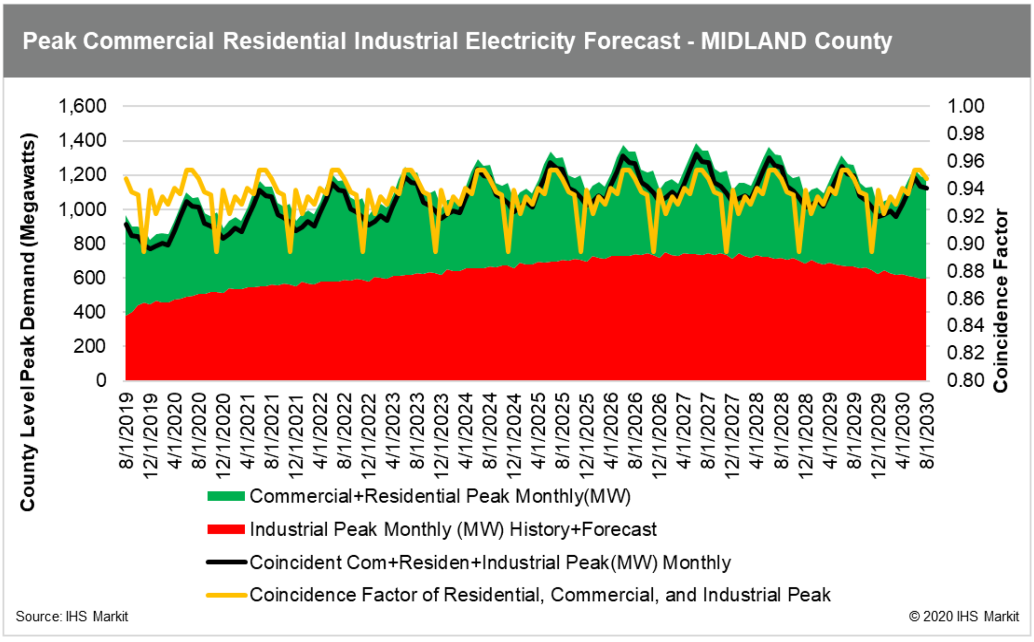


Figure 3-1. Total Midland County Peak Forecast

- **Coincident Commercial+Residential+Industrial Peak (MW) Monthly:** This is the black line. It is always less than the top of the green graph. Visually, it is calculated as the (green + red) *yellow line. If, for example, there is 500 MW of industrial peak demand and 250 MW of commercial peak demand and 250 MW of residential peak the actual total shown in the black line it would not be 1,000 MW, but instead 1,000 MW * the coincidence factors. The average monthly coincidence factors applied to the entire Permian region range from 92% to 94%. The total peak would be the total 1,000 MW multiplied by 0.92 to 0.94 for most of the year. This gives 920 MW to 940 MW as a coincident peak.

4.3.4 Peak Load Forecast by Region

The Delaware Basin's power demand is completely dominated by the industrial sector where oil and gas activity is expected to grow. Growth is expected within the residential and commercial sectors, but it will constitute a small fraction of the power forecast in the Delaware Basin. The average monthly coincidence factors for this region range from 0.94 to 0.98. Peak power for all sectors is expected to increase by 294% from 1,300 MW at the 2019 peak to 4,900 MW at the 2030 peak.

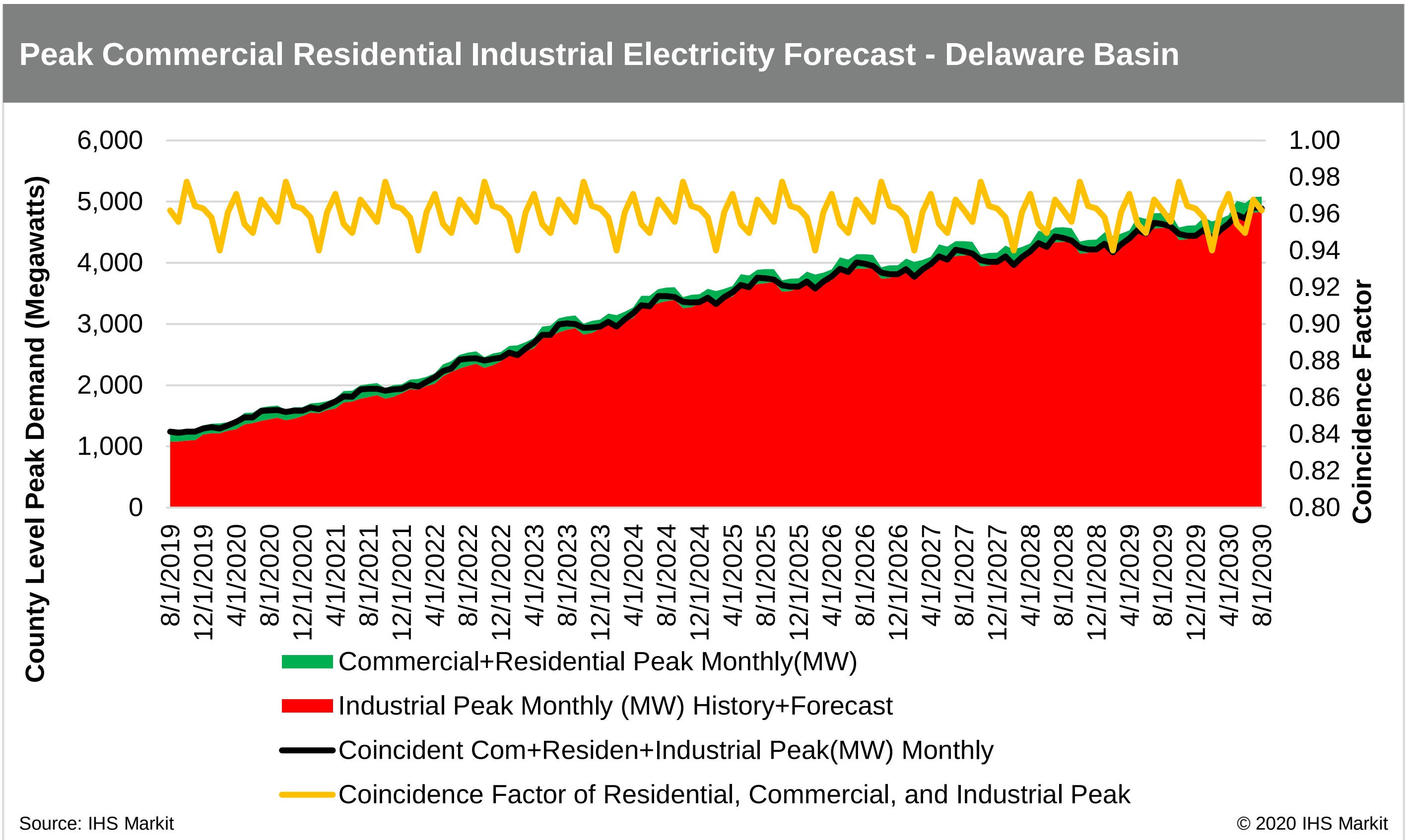


Figure 3-2. Total Delaware Basin Peak Forecast

The Midland Basin's power demand has a large contribution from residential and commercial activity, but the industrial sector accounts for the majority of the existing load. Since the growth rate in the industrial sector will be higher, the residential and commercial power will become a smaller percentage of the load served over the next decade. The average monthly coincidence factors for this region range from 0.94 to 0.97. Peak power for all sectors is expected to increase by over 56% from just over 2,040 MW at the 2019 peak to nearly 3,200 MW at the 2030 peak.

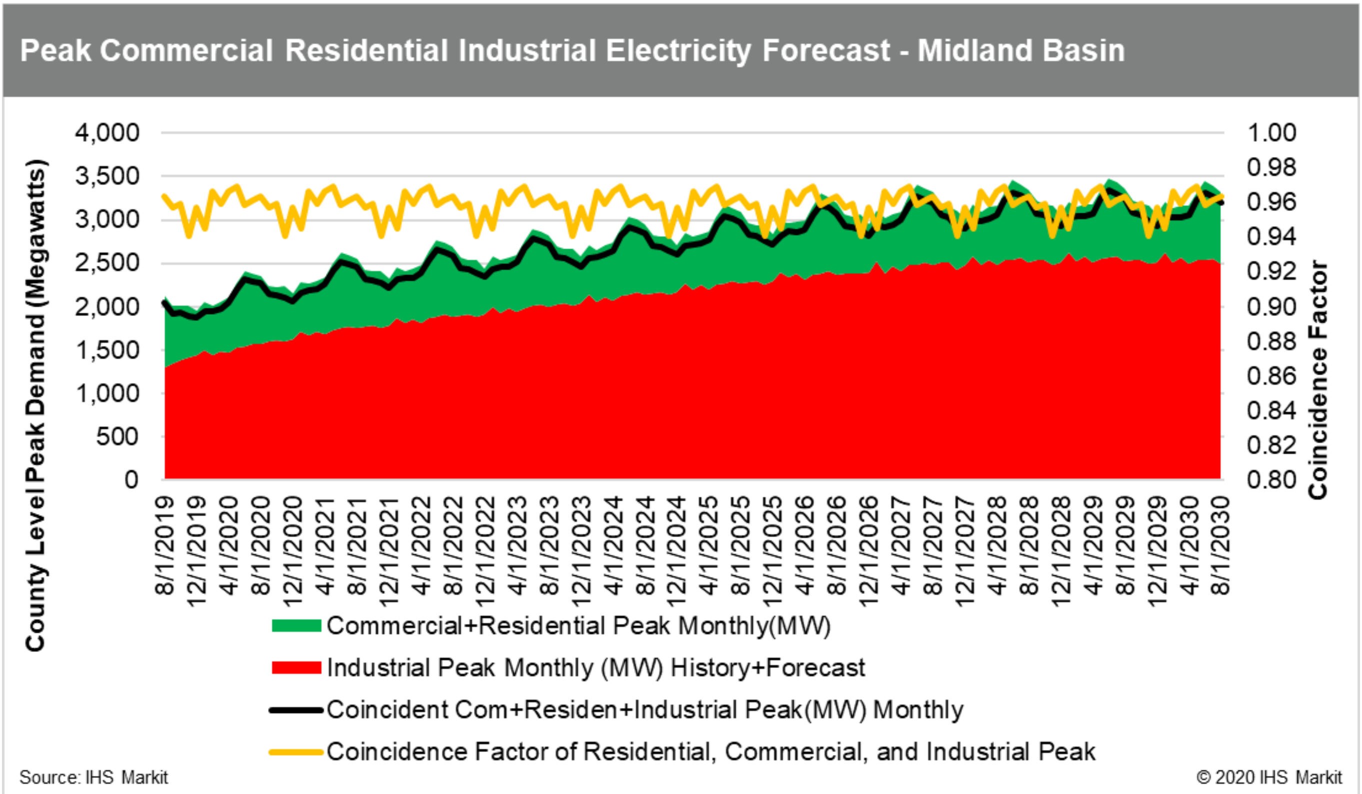


Figure 3-3. Total Midland Basin Peak Forecast

The Central Basin Platform's power demand has a substantial contribution from residential and commercial activity much like the Midland Basin. However, residential and commercial power will become even more important over the next decade as the oil and gas activity stagnates in this region. The average monthly coincidence factors for this region range from 0.93 to 0.96. Peak power for all sectors is expected to increase by 10% from 1,250 MW at the 2019 peak to just 1,370 MW by the 2030 peak.

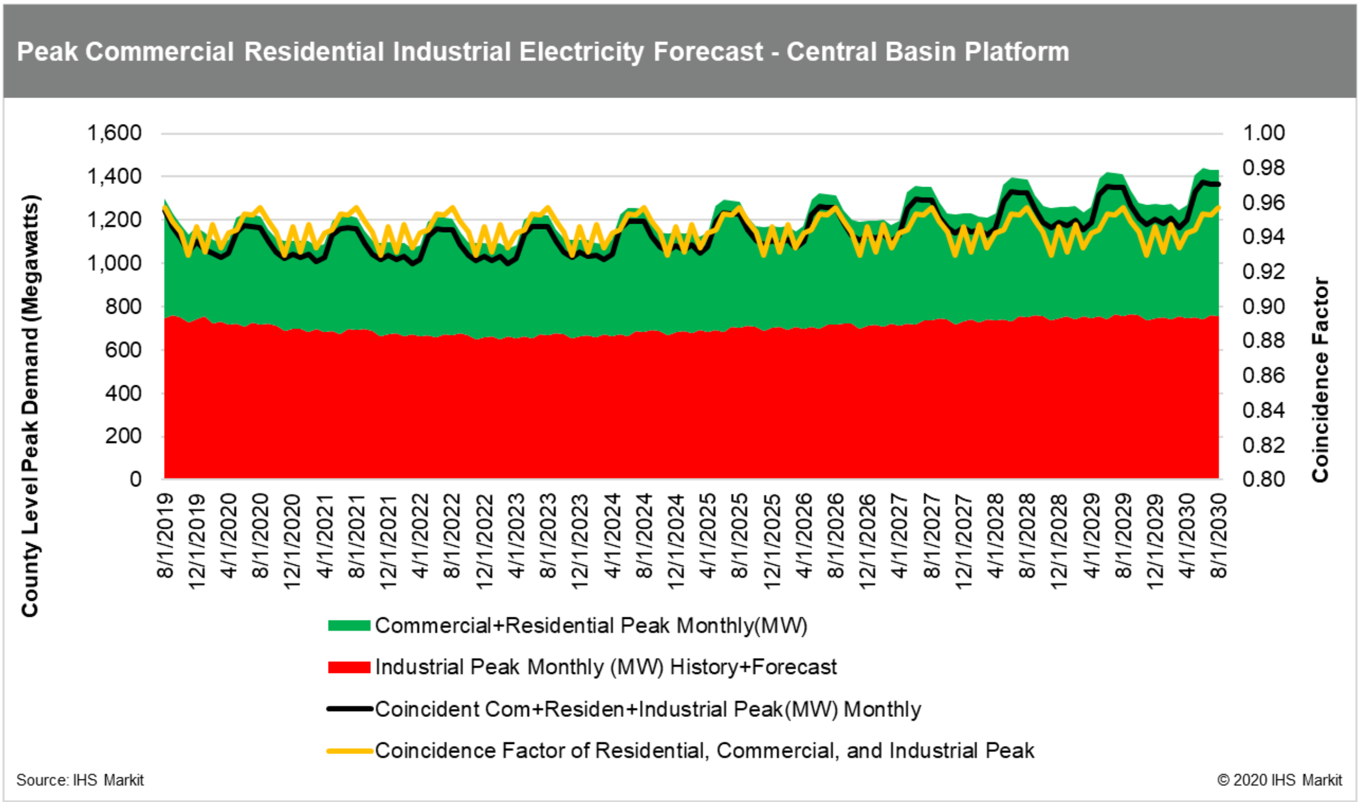
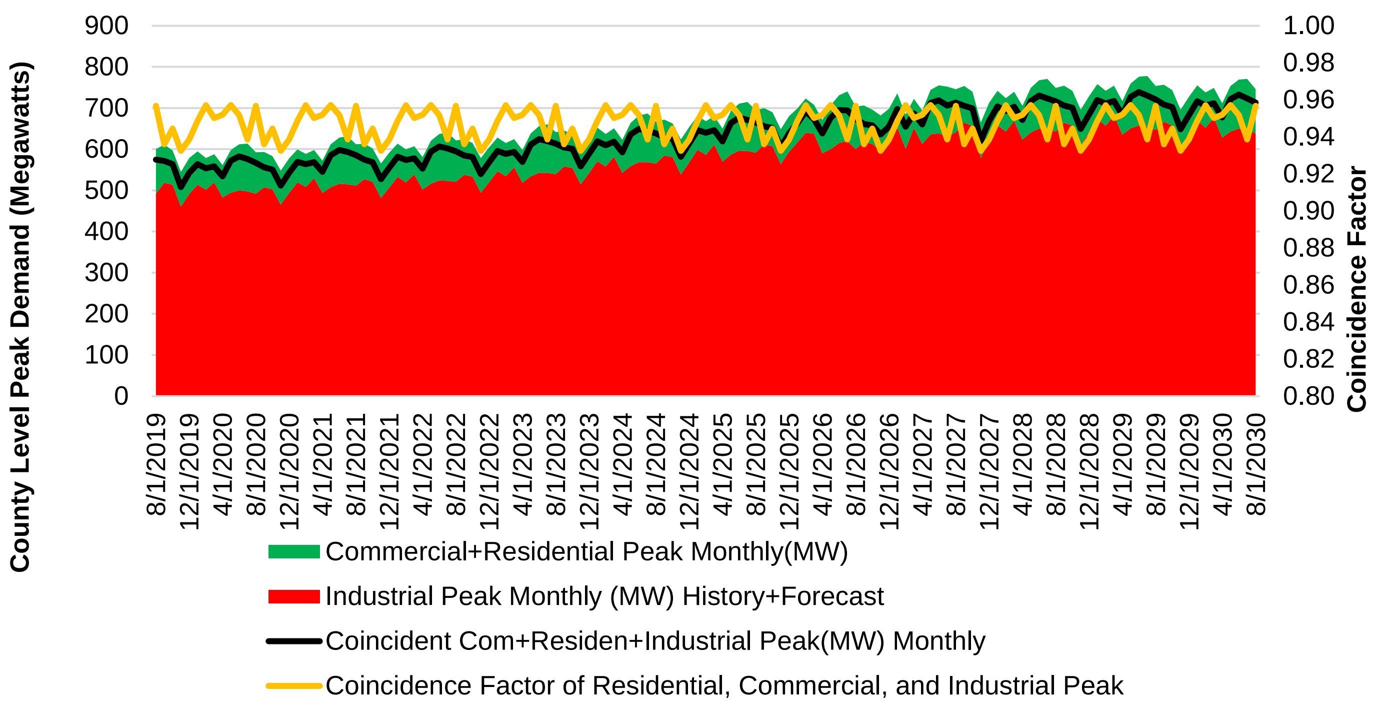


Figure 3-4. Total Central Basin Platform Peak Forecast

Power demand in the Fringe area of the Permian Basin currently has only a minor contribution from residential and commercial activity which is expected to remain relatively constant throughout the study. Most of the Fringe area's growth will come from the industrial sector, but growth will be limited since oil and gas activity is not expected to ramp up much over the next decade. The average monthly coincidence factors for this region range from 0.93 to 0.96. Peak power for all sectors is expected to increase by only 24% from 570 MW at the 2019 peak to 710 MW at the 2030 peak.

Peak Commercial Residential Industrial Electricity Forecast - Fringe



Source: IHS Markit

Figure 3-5. Total Fringe Area Peak Forecast

4.4 Total Permian Peak Load Forecast

Overall, the Permian region's power demand is dominated by the industrial sector where most of the growth is expected. Still, power demand is expected to grow in all sectors. The average monthly coincidence factors applied to the entire Permian region range from 94% to 98%. Peak power for all sectors is expected to almost double from just under 5,200 MW at the 2019 peak to nearly 10,200 MW at the 2030 peak.

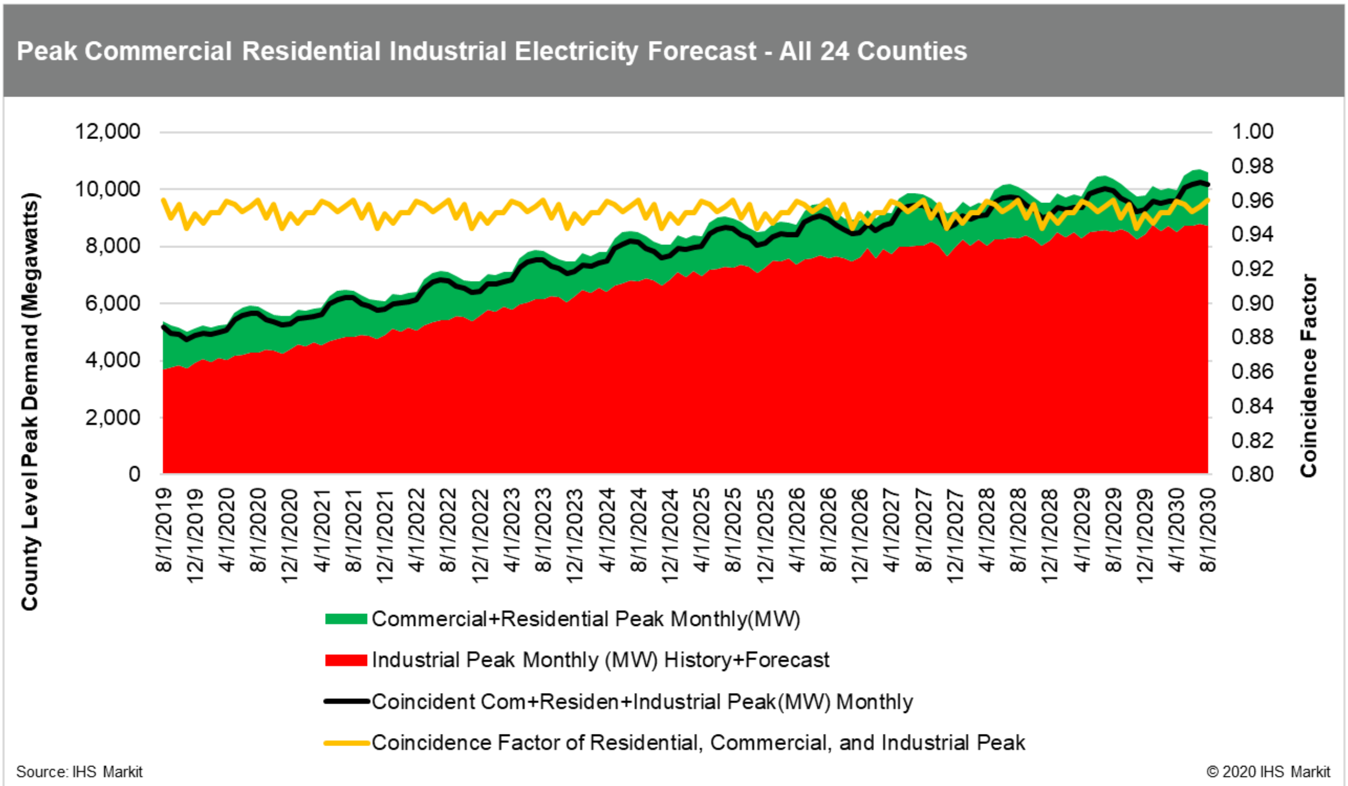


Figure 3-6. Total Permian Far West Texas Weather Zone Peak Forecast by

In the chart below (figure 3-7) it can be seen that the Delaware Basin load is expected to have the highest growth rate in the Permian through 2030. From 2019 to 2030 the Delaware Basin is expected to move from being a moderate component of the Permian power used to comprising over half of the total load as its growth rate is expected to be very high. The other areas of the Permian are also expected to grow, but their industrial sectors are limited by weaker geological potential. Current and projected growth for all regions is also summarized in table 3-1 below.

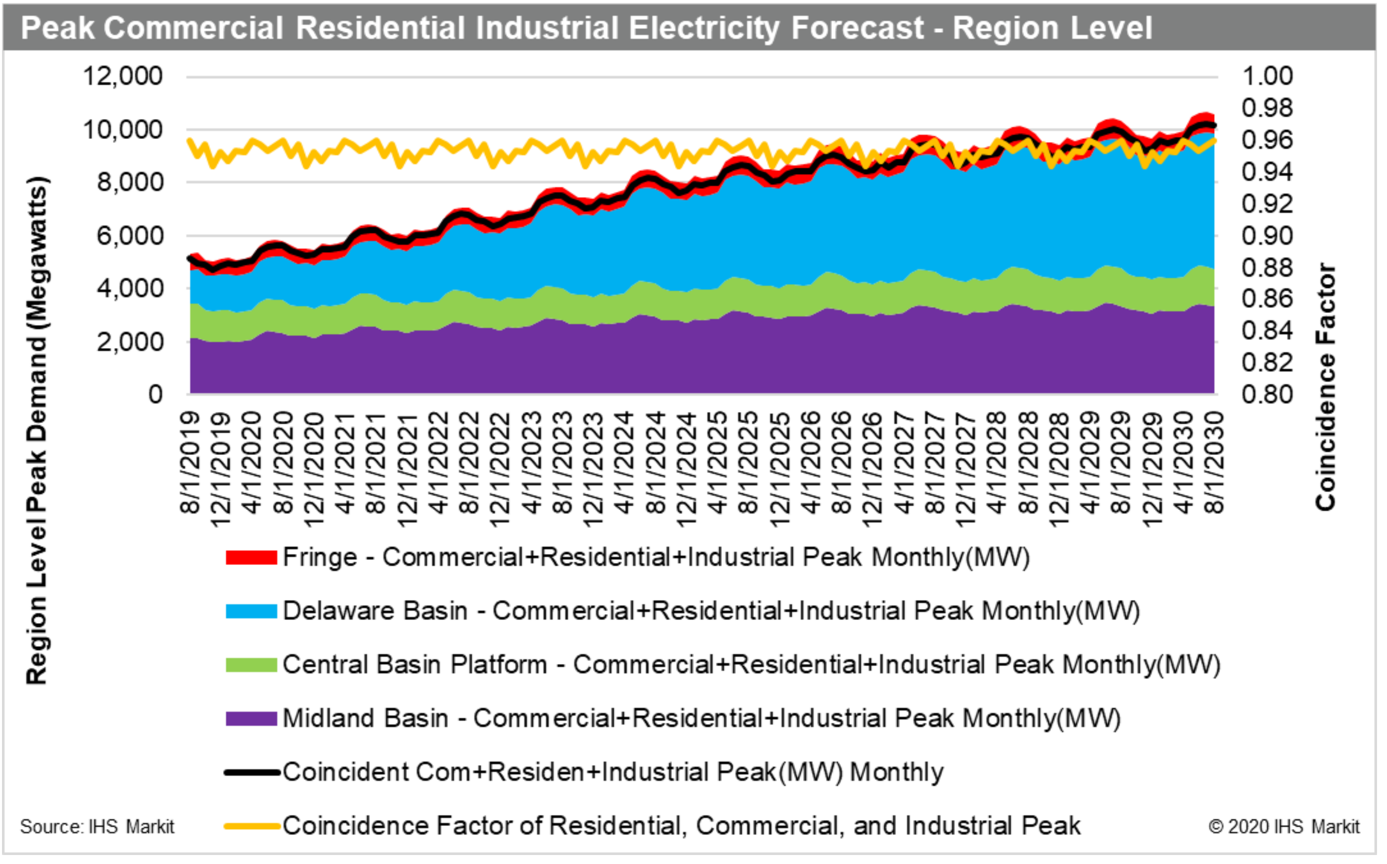


Figure 3-7. Total Permian Far West Texas Weather Zone Peak Forecast by Region

Region	Current	2030 Forecast	Increase
Delaware Basin	1,300 MW	4,900 MW	294%
Midland Basin	2,040 MW	3,200 MW	56%
Central Basin	1,250 MW	1,370 MW	10%
Fringe	570 MW	710 MW	24%
Total	5,160 MW	10,200 MW	97%

Table 3-1. Summary of total load increases by region for the Permian Basin.