BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF SOUTHWESTERN PUBLIC SERVICE COMPANY'S APPLICATION REQUESTING APPROVAL TO RETIRE AND ABANDON PLANT X GENERATING STATION UNIT 1, PLANT X GENERATING STATION UNIT 2, AND CUNNINGHAM GENERATING STATION UNIT 1, AND DETERMINATION OF RELATED RATEMAKING PRINCIPLES AND TREATMENT.	)	**CASE NO. 18-00329-UT**
SOUTHWESTERN PUBLIC SERVICE COMPANY,	)	
APPLICANT.	)	

SUPPLEMENTAL DIRECT TESTIMONY

of

WILLIAM A. GRANT

on behalf of

SOUTHWESTERN PUBLIC SERVICE COMPANY

DECEMBER 10, 2018

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GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	Meaning
Btu	British thermal unit
Commission	New Mexico Public Regulation Commission
Cunningham 1	Cunningham Generating Station Unit 1
FERC	Federal Energy Regulatory Commission
IRP	Integrated Resource Plan
kWh	kilowatt-hour
O&M	operation and maintenance
Plant X 1	Plant X Generating Station Unit 1
Plant X 2	Plant X Generating Station Unit 2
PUCT	Public Utility Commission of Texas
RTO	Regional Transmission Organization
SPP	Southwest Power Pool
SPS	Southwestern Public Service Company, a New Mexico corporation
Xcel Energy	Xcel Energy Inc.

LIST OF ATTACHMENTS

Attachment	**Description**
WAG-S1	Article discussing in-service date of Permian Basin pipeline
WAG-S2	Excerpt from SPS's 2018 Integrated Resource Plan filing

Case No. 18-00329-UT
Supplemental Direct Testimony
of
William A. Grant

I. WITNESS IDENTIFICATION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is William A. Grant. My business address is 790 South Buchanan Street, Amarillo, Texas 79101.

Q. On whose behalf are you testifying in this proceeding?

A. I am filing testimony on behalf of Southwestern Public Service Company, a New Mexico corporation ("SPS") and wholly-owned electric utility subsidiary of Xcel Energy Inc. ("Xcel Energy").

Q. By whom are you employed and in what position?

A. I am employed by SPS as Regional Vice President, Regulatory and Strategic Planning.

Q. Please briefly outline your responsibilities as Regional Vice President, Regulatory and Strategic Planning.

A. I am responsible for determining the appropriate planning strategy for SPS. In this role, I work with generation and transmission planning personnel and coordinate with the Southwest Power Pool ("SPP") on regional policy and cost allocation issues affecting SPS. I am also responsible for:

- overseeing the activities of the SPS regulatory department to ensure that SPS meets the regulatory requirements of the New Mexico Public

Regulation Commission ("Commission") and the Public Utility Commission of Texas ("PUCT") as well as the Federal Energy Regulatory Commission ("FERC"); and

- overseeing the relationships with the state and federal commissions and managing the relationships and policy decisions with SPP.

Q. Please describe your professional experience.

A. I have over 30 years of experience in both power plant and system operations at Xcel Energy and its predecessors. I have had responsibility for operating several different types of electric generating units ranging from diesel generators, coal-fired steam electric stations, and gas-fired steam units and combustion turbines. I have five years of experience as a System Operator for the SPS transmission control center. For seven years, I was Director, Power Operations for Xcel Energy Services Inc., where I was responsible for the economic dispatch and analytical support for all of the Xcel Energy Operating Companies, including SPS. For seven years, I was Manager, Transmission Control Center and Wind Integration, for SPS. In 2012, I was named Director, Strategic Planning, for SPS. In 2017, I was named Regional Vice President of Regulatory and Strategic Planning.

Q. Please describe your experience with Regional Transmission Organizations ("RTO").

A. Over my career, I have had extensive experience with RTOs and transmission coordination organizations, including serving on a number of committees in SPP and the Western Electricity Coordinating Council. Currently, I serve on the SPP Markets and Operations Policy Committee and the Strategic Planning Committee. I have also served on the Consolidated Balancing Authority Steering Committee and the Operations Reliability Working Group, and I have chaired the wind integration taskforce. Additionally, I am familiar with the Midcontinent Independent System Operator Day 2 Market development and implementation.

Q. Have you testified before any regulatory authorities?

A. Yes. I have testified before the Commission, the PUCT, the Colorado Public Utilities Commission, and FERC.

II. ASSIGNMENT AND SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. What is your assignment in this supplemental direct testimony?

A. My assignment in this supplemental direct testimony is to answer some of the questions posed by the Hearing Examiner during the Prehearing Conference held in this case on November 20, 2018. In addition, I introduce the other SPS witnesses who will provide the remaining responses to the Hearing Examiner's questions.

Q. What other witnesses are offering supplemental direct testimony on the issues raised by the Hearing Examiner?

A. SPS witness Randy J. Larson will address certain questions related to the operations of Plant X Generating Station Unit 1 ("Plant X 1"), Plant X Generating Station Unit 2 ("Plant X 2"), and Cunningham Generating Station Unit 1 ("Cunningham 1"). SPS witness Melissa L. Ostrom will respond to questions regarding depreciation and dismantling costs. Ms. Ostrom also addresses questions regarding the accounting applicable to the proposed relief SPS has requested. Both Mr. Larson and Ms. Ostrom provided prefiled direct testimony in this proceeding as well.

Q. Why is SPS offering the testimony of three witnesses in response to the Hearing Examiner's questions?

A. Generally speaking, the questions fall into three distinct categories: (1) operation of the three units that SPS seeks to retire; (2) depreciation and accounting issues related to the units; and (3) the ratemaking treatment requested by SPS in this proceeding. No single witness has the expertise to address all of those issues in depth, so SPS is offering the testimony of three witnesses to ensure that it adequately responds to the Hearing Examiner's questions in a complete and accurate manner.

III. RELIEF REQUESTED BY SPS

Q. Why is SPS requesting that the Commission approve accounting orders in this case, rather than in a later case?

A. SPS is seeking approval of accounting orders in this case because: (1) it believes it was directed in Case No. 17-00255-UT[1] to address abandonment and accounting issues together, and all of the relevant facts and issues are before the Commission in this Application; and (2) it wants to ensure that both it and customers are kept whole after the retirement of Plant X 1, Plant X 2, and Cunningham 1.

Q. Please explain what you mean when you state that the accounting orders requested in this case would keep both SPS and customers whole.

A. SPS is seeking two types of accounting orders in this case: (1) an order that allows SPS to recover the remaining unrecovered depreciation and estimated dismantling costs associated with the three units in some future proceeding; and (2) an order that authorizes SPS to refund or recover the difference between estimated and actual dismantling costs for each unit.

[1] *In the Matter of Southwestern Public Service Company's Application for Revision of its Retail Electric Rates Pursuant to Advice Notice No. 272*, Case No. 17-00255-UT, Final Order Adopting Recommended Decision with Modifications (Sept. 5, 2018).

An order that allows SPS to recover the remaining unrecovered depreciation and estimated dismantling costs provides SPS with the certainty that it will not have to write off those amounts at some later date, and it ensures that customers pay the costs of the units that have served them for over 60 years. That is consistent with my understanding of the regulatory compact, which allows a utility a reasonable opportunity to recover the reasonable and necessary costs of facilities used to serve customers. Consideration and resolution of this matter seems appropriate under the Commission's use of the *Commuters' Committee* standards for evaluating present and future public convenience and necessity (discussed by Mr. Larson in his testimony).

An order that allows SPS to refund or recover the difference between estimated and actual dismantling costs ensures that customers pay the actual costs of dismantling the units, but no more. Without an accounting order authorizing the true-up, customers could end up paying more than the actual dismantling costs. SPS wants to recover only the actual dismantling costs—no more and no less.

Q. Why is it reasonable for the Commission to provide the accounting orders in this case, rather than waiting until a later case to rule on SPS's request for recovery of the remaining unrecovered costs?

A. As Mr. Larson explains in his direct testimony, retiring Cunningham 1 three years before the end of its current Commission-approved service life will save customers approximately $15.5 million of capital and operation and maintenance ("O&M") expense that would otherwise be necessary to keep the unit running.[2] That translates to approximately $3.4 million on a New Mexico retail basis. Retiring Plant X 1 and Plant X 2 will save another $10.5 million ($2.3 million New Mexico retail) of incremental capital and O&M costs that would be necessary to keep those units running past the end of their current Commission-approved service lives.[3] SPS has been proactive in searching for and identifying these cost savings opportunities, and it should not be forced to bear the risk associated with the unnecessary deferral of the recovery question to a later case, which would be removed in time from the actual decision to retire or abandon the units. A policy of separating the issues in that way would tend to discourage

[2] Direct Testimony of Randy J. Larson at 6-7.

[3] Direct Testimony of Randy J. Larson at 6.

utilities from actively seeking to achieve these types of cost savings for customers. As I previously mentioned, weighing of such financial matters seems appropriate under the *Commuters' Committee* standard.

I would also emphasize the specific facts and circumstances of this case and these units. These are not "early" retirements of the units in any normal sense of the term, and certainly are not "premature" retirements. Rather, as discussed in Mr. Larson's supplemental direct testimony, the units have actually already far outlived their original expected service lives. While there are remaining undepreciated balances associated with the units due to capital additions and changes in depreciation schedules, SPS has actually already ensured that customers have derived many more years of benefit from the units than could be reasonably anticipated.

Finally, it is SPS's understanding based on its recently-concluded rate case that the questions of abandonment and accounting treatment are to be addressed together, outside of a rate case.[4] This would, therefore, be the time to address these issues.

[4] Case No. 17-00255-UT, Recommended Decision at 159, (Jun, 29, 2018) ("Commission precedent supports Staff's position that it is premature to shorten the service life of Cunningham Unit 1 until SPS actually decides and requests approval to retire the Unit.").

Q. If the Commission does not approve SPS's ratemaking treatment in this case, is SPS precluded from seeking recovery of the costs associated with the retired units in a future case?

A. I am not an attorney, and so I do not intend to express a legal opinion in my answer to this question. But based on my decades of experience in the utility industry, it is my understanding that SPS would not be precluded from seeking recovery of the costs associated with the retired units in a future case unless the Commission affirmatively finds in this case that SPS is not entitled to recover those costs for some reason. Or stated differently, if the Commission decides in this case not to address the issue of whether SPS is entitled to recover the remaining unrecovered costs associated with the three units, it is my understanding that SPS could seek recovery of those costs in a future case.

Q. In what proceeding would SPS seek a determination of the justness and reasonableness of the costs associated with the retired plants if the Commission does not make that determination in this case?

A. If the Commission does not decide the justness and reasonableness of the remaining unrecovered costs associated with the retired plants in this case, SPS would likely seek recovery of those costs in the first rate case after the plants are

taken out of service. It is possible, however, that SPS would file a standalone proceeding to seek approval of an accounting order that would allow recovery in a subsequent rate case.

Q. Mr. Larson testified that SPS may seek to either refund or recover the difference between the actual and estimated dismantling costs. When does SPS expect to make such a filing?

A. SPS expects to make such a filing after each of the three units are actually dismantled, which will be after all of the other units at a particular generating facility are retired. For example, even though SPS is seeking Commission approval to retire Plant X 1 and Plant X 2 in this proceeding, the last remaining unit at the Plant X Generating Station will not be retired until 2027. Thus, SPS will likely not seek permission to refund or recover the disparity between actual and estimated dismantling costs for Plant X 1 and Plant X 2 until 2028, at the earliest. Because the longest-lived unit at the Cunningham Generating Station, will not be retired until 2040, SPS will not file to recover or refund the difference between estimated and actual dismantling costs for Cunningham 1 until 2041 or afterward.

IV. OPERATION OF GENERATING UNITS

Q. One of the Hearing Examiner's questions asks about the efficiency of the three units that SPS seeks permission to retire. Does the electric industry have a metric to evaluate the efficiency of a generating unit?

A. Yes. The efficiency of a generating unit is typically measured by its "heat rate," which is the amount of energy used by the generating unit to produce one kilowatt-hour ("kWh") of electricity. In general, heat rate is measured by the number of British thermal units ("Btu") per net kWh generated.[5] Thus, for example, a unit with a 10,000 heat rate uses 10,000 Btus of energy from sources such as natural gas or coal to produce one kWh.

Q. Plant X 1, Plant X 2, and Cunningham 1 are all steam turbines. What is the typical heat rate for a steam turbine unit?

A. Heat rates for steam turbines vary, with newer units typically having lower heat rates than older units. According to the U.S. Energy Information Administration, the average heat rate for steam turbines fueled by natural gas was 10,353 Btu/kWh in 2017.[6] That average, however, includes both newer plants and older

[5] *See* https://www.eia.gov/tools/faqs/faq.php?id=107&t=3

[6] https://www.eia.gov/electricity/annual/html/epa_08_02.html

plants, and it is reported at full load conditions, meaning that the older units are likely running.[7] If the average heat rate were measured at a time of lighter loading, many of the older units would not be running, and the average heat rate of the units actually running would be considerably lower.

Q. How does the heat rate affect the frequency at which a unit is generating?

A. SPP has the responsibility to determine which generating units will be operating in a given time interval, and SPP bases that decision on Security Constrained Economic Dispatch. That means SPP accepts offers from all generators to run their units in a particular hour, and SPP stacks the offers in economic order, with the lowest-cost units being dispatched (i.e., ordered to run) first. SPP then dispatches the next lowest-cost unit, and then the next one, etc., until the entire load is served.[8] A unit with a high heat rate typically sits very high on the economic dispatch stack because it takes more fuel to produce one kWh of electricity. Therefore, units with high heat rates are not dispatched as often as units with lower heat rates.

[7] *Id.*

[8] Transmission constraints and other factors may require SPP to dispatch units out of economic order in some circumstances. Hence the phrase "Security Constrained Economic Dispatch," which means that pure economic dispatch must sometimes take a back seat to the security and reliability of the grid.

Q. What are the typical heat rates at which the load is fully served in SPS's service area?

A. The answer to that question depends on the amount of load, of course, as well as on the number and types of generating units that are available to run. During the months in which lower-cost units are out of service for maintenance, for example, the market-clearing heat rate may be higher than it is when the lower-cost units are available to run. Generally speaking, however, generating units with heat rates above 10,500 Btu/kWh do not run except on the highest peak days.[9]

Q. With that background, please describe the efficiency of the three units that SPS seeks to retire in terms of their heat rates.

A. All three of the units that SPS seeks to retire are peaking units with high heat rates. Table WAG-S1 reflects the average heat rate of each unit:

Table WAG-S1

	Plant X 1	**Plant X 2**	**Cunningham 1**
Average Heat Rate (Btu/kWh)	13,640[10]	13,209	11,926

[9] Units with higher heat rates run are sometimes dispatched during hours other than peak loading hours, but that is typically because those units have special characteristics such as quick-start capability and low minimum-run times. None of the units at issue in this proceeding have such characteristics.

[10] This is the average heat rate used by SPS when offering the output of Plant X 1 to SPP for economic dispatch. The heat rates for the other two units are derived from SPS's 2018 Integrated Resource Plan ("IRP") filing.

Q. In direct testimony, Mr. Larson stated that the three units that SPS seeks to retire are unlikely to be dispatched. Do you agree with that statement?

A. Yes. The three units are expensive to run in most hours because they have relatively high heat rates. Thus, under normal conditions they will seldom, if ever, be dispatched by SPP.

Q. How often does each of the three units currently run?

A. Table WAG-S2 contains the capacity factor for each unit in the last four calendar years.[11]

Table WAG-S2

	Plant X 1	**Plant X 2**	**Cunningham 1**
2017	0%	8%	21%
2016	5%	15%	25%
2015	2%	17%	17%
2014	5%	23%	18%

[11] A unit's capacity factor is the ratio of hours the unit actually runs compared to the total number of hours in a year.

Q. The capacity factors of Cunningham 1 increased in 2016 and 2017, relative to what they were in prior years, and the capacity factor of Plant X 1 increased from 2015 to 2016. Why did those increases occur?

A. Those increases are due primarily to the anomalously low gas prices available in the southern part of SPS's service area during the past few years. Cunningham 1 is located in the Permian Basin, and both Plant X 1 and Plant X 2 are located near the Permian Basin. In recent years the production of natural gas in that area has outstripped the transportation capacity of the natural gas pipelines in the area, resulting in "trapped gas" that SPS can acquire at prices that are lower than the prices quoted for gas from the major gas trading hubs, such as the Henry Hub. For example, SPS has been able to acquire natural gas for as low as $0.60 per million Btu in the southern part of its service area in recent months, compared to prices of roughly $3.00 per million Btu in other parts of the SPS service area. Because the price at which SPS offers its generation to SPP is determined largely by gas prices and heat rates, the lower gas prices mean Cunningham 1 has been dispatched more often in the last two years than it otherwise would be. To a lesser extent, that is also true of Plant X 1 and Plant X 2.

Q. Does SPS expect those units to continue running at the same level in the future?

A. No, for several reasons. First, a natural gas pipeline currently under construction is expected to be in service sometime in 2019, and that pipeline will allow natural gas to be transported from the Permian Basin to the major trading hubs or the liquefied natural gas terminals on the Texas coast.[12] When that occurs, SPS will no longer have access to the abnormally low-priced natural gas in the southern part of its service area, which will significantly reduce the number of times that Plant X 1, Plant X 2, and Cunningham 1 are dispatched.

Second, a 345-kilovolt transmission line from the TUCO Substation to the Hobbs Substation is scheduled to be completed in the first half of 2020. When that occurs, it will remove existing transmission constraints and allow SPS to use lower-cost power from other parts of the SPP footprint to serve load in the Permian Basin area, instead of having to rely on high-heat-rate units such as the Plant X units and Cunningham 1. That too will reduce the number of times that Plant X 1, Plant X 2, and Cunningham 1 are dispatched.

[12] Attachment WAG-S1 is an article discussing the in-service date for the new pipeline from the Permian Basin.

Third, the 478-megawatt Hale Wind Project will be placed in service in 2019, and the 522-megawatt Sagamore Wind Project will be placed in service in 2020. In addition, the 230-megawatt Bonita wind facilities will be placed in service in late 2018. That 1,230 megawatts of wind energy will push Plant X 1, Plant X 2, and Cunningham 1 much higher on the economic dispatch stack during the hours in which the wind facilities are producing electricity, which will reduce the likelihood of the units being dispatched.

Q. Mr. Larson's direct testimony described the savings that would result from retiring Plant X 1, Plant X 2, and Cunnigham 1. Did those savings include fuel savings as well as expense savings?

No. The savings identified in Mr Larson's testimony include only the incremental capital and O&M expense that SPS will avoid by retiring Plant X 1 and Cunningham 1 in 2019 and by retiring Plant X 2 in 2020.

Q. Does SPS expect to experience fuel savings if it retires Plant X 1, Plant X 2, and Cunningham 1 at the times requested in this proceeding?

A. No. SPS does not expect to realize any fuel savings from Plant X 1, Plant X 2, and Cunningham 1, regardless of whether they are retired or they remain in service.

Q. Why does SPS not expect to realize any fuel savings from the three units regardless of the Commission's decision in this proceeding?

A. SPS does not expect to realize fuel savings because the units will not be running at all if they are taken out of service, and they are highly unlikely to run even if they remain in service. Fuel savings occur when a unit with a lower fuel cost runs in lieu of a unit with a higher fuel cost. If the units are retired, they will never run, so they cannot produce fuel savings. But even if the Commission were to deny SPS's request to retire the units, they still would not be dispatched by SPP very often for the reasons I discussed earlier: (1) the extremely low "trapped gas" prices will no longer be available after the new gas pipeline goes into service, (2) the new 345-kilovolt transmission line will remove transmission constraints and allow units from elsewhere in SPP to serve the southern part of SPS's service area, and (3) the addition of 1,230 megawatts of wind nameplate capacity will move the three units farther up the dispatch stack.

Q. Will the retirements of Plant X 1, Plant X 2, and Cunningham 1 have a negative effect on SPS's system or its customers?

A. No, for the reasons I have explained. The units' high heat rates mean that SPP will seldom, if ever, dispatch the units, particularly after the natural gas prices in

the Permian Basin area return to normal, the new transmission line is placed in service, and the new wind facilities go into service.

Q. Are you familiar with the *Commuters' Committee* factors that Mr. Larson described in his direct testimony in this case?

A. Yes. I have reviewed Mr. Larson's testimony, and I am familiar with the factors he addresses.

Q. With respect to the fourth *Commuters' Committee* factor—availability and adequacy of service to be substituted—how does SPS propose to replace Plant X 1, Plant X 2, and Cunningham 1 if necessary?

A. This question implicitly assumes that Plant X 1, Plant X 2, and Cunningham 1 are dedicated to serving the SPS load, which is not true. SPS serves its load using the cheapest power available in a given hour from the SPP Integrated Marketplace, and the power used to serve SPS's load may come from a variety of generation suppliers, not just SPS's own generating units. Or looked at from another perspective, SPS's generating units serve the load that exists at the particular time the units are dispatched by SPP, regardless of whose retail customers are consuming the power. In essence, SPS (in its capacity as a load-serving entity) purchases all of the power needed to serve retail customers from the market, and

SPS (in its capacity as a generator) sells all of its output into the market. Given these circumstances, it is incorrect to think of SPS's generating units as serving SPS load.

Because the SPS generating units are not dedicated to serving SPS load, and because there is adequate generating capacity within the SPP footprint without Plant X 1, Plant X 2, and Cunningham 1,[13] the question of the availability and adequacy of service without the three units is essentially an economic one—are there times when SPS's customers will pay more for the power used to serve them if SPP retires Plant X 1, Plant X 2, and Cunningham 1? The answer to that question is no for the reasons I have explained—Plant X 1, Plant X 2, and Cunningham 1 would seldom be dispatched even if they remained in service because of the new gas pipeline, the new transmission line, and the new wind facilities. Instead, SPS's load will nearly always be served by the new wind facilities or by lower-cost units from other parts of the SPP footprint.

[13] SPP currently has a reserve margin of 26.3%. If Plant X 1, Plant X 2, and Cunningham 1 are retired, the reserve margin will be 25.9%, which is not a material reduction.

Q. In his direct testimony, Mr. Larson testifies that, if necessary, SPS could purchase power from the SPP Integrated Marketplace to meet the needs of customers.[14] What would those purchases cost?

A. As I explained earlier, SPS purchases all of the power used to serve its customers from the SPP Integrated Marketplace. The amounts SPS must pay for those purchases will vary by hour, but those costs will be lower than they would be if SPS obtained the power from Plant X 1, Plant X 2, or Cunningham 1. For the reasons I discussed earlier, those three units will seldom, if ever, be dispatched because of their high heat rates, even if the Commission requires that they remain in service.

[14] Direct Testimony of Randy J. Larson at 12.

V. RESPONSES TO OTHER QUESTIONS

Q. Were the retirement dates that SPS has proposed for Plant X 1, Plant X 2, and Cunningham 1 included in SPS's 2018 IRP filing?

A. Yes. Attachment WAG-S2 contains the pertinent page from SPS's 2018 IRP filing.[15] As shown in the attachment, SPS assumed in the 2018 IRP filing that:

- Plant X 1 would retire in 2019,
- Plant X 2 would retire in 2020, and
- Cunningham 1 would retire in 2019.

Q. Does this conclude your prefiled supplemental direct testimony?

A. Yes.

[15] *In the Matter of Southwestern Public Service Company's 2018 Integrated Resource Plan for New Mexico*, Case No. 18-00215-UT, Final Order (Dec.5, 2018).

VERIFICATION

STATE OF TEXAS)
) ss.
COUNTY OF POTTER)

WILLIAM A. GRANT, first being sworn on his oath, states:

I am the witness identified in the preceding supplemental direct testimony. I have read the supplemental direct testimony and the accompanying attachment(s) and am familiar with their contents. Based upon my personal knowledge, the facts stated in the supplemental direct testimony are true. In addition, in my judgment and based upon my professional experience, the opinions and conclusions stated in the testimony are true, valid, and accurate.

William A Grant
WILLIAM A. GRANT

SUBSCRIBED AND SWORN TO before me this 6 day of December, 2018 by WILLIAM A. GRANT.

MARY C. JOHNSON
Notary Public, State of Texas
Notary ID #12084834
My Commission Expires 08-28-2020

Mary C Johnson
Notary Public, State of Texas
My Commission Expires: 8-28-2020

NATURAL GAS — 19 Oct 2018 | 19:15 UTC — Denver

Analysis: Permian Basin gas constraints on track to ease in 2019

Author Eklavya Gupte
Editor Keiron Greenhalgh
Commodity Natural Gas

HIGHLIGHTS

Proposed pipeline capacity of 14 Bcf/d

West Texas Waha Hub prices recover sharply

Denver — Natural gas production in the Permian Basin has outpaced pipeline takeaway capacity, but with the rollout of new projects, this trend is expected to change next year.

Multiple proposed pipelines are expected to come online in the next four years that could help alleviate Permian gas constraints. The Permian Basin has around 14 Bcf/d of proposed pipeline capacity scheduled to commence service between now and 2022.

Related story: Falling Permian well performance could pose risk to longer-term growth: Schlumberger

Related story: New gas-fired generation to boost Appalachia gas demand

News of these ventures, coupled with a rise in demand, is also beginning to support prices at the West Texas Waha gas hub.

The Gulf Coast Express (GCX) pipeline project, which will transport gas from West Texas to the Agua Dulce Hub, has a design capacity of 1.98 Bcf/d and is expected to be in service by October 2019.

The Permian Highway Pipeline, which will transport 2 Bcf/d of gas from the Permian to the Texas Gulf Coast, received a final investment decision in September. Gas for this infrastructure will be sourced from existing Kinder Morgan, EagleClaw and Apache systems, with additional interconnections to both intrastate and interstate pipelines in the Waha area.

The project will also enable volumes to reach the Katy and Waha hubs, the Coastal Bend and Kinder Morgan Tejas headers connected to key LNG export facilities at Freeport and Corpus Christi.

PRODUCTION

Analysts say this line will play a pivotal role in not only the regional production growth narrative, but also the subsequent growing demand centers it will ultimately feed.

Other projects include the 2 Bcf/d Pecos Trail Pipeline, which will transport Permian gas to the Agua Dulce Hub along with the 240-mile North Texas Expansion line.

Permian dry gas production is up a little more than 1 Bcf/d year on year in October at an average of 7.7 Bcf/d, according to S&P Global Platts Analytics.

Crude is still the primary target for Permian producers, but gas output is also surging.

Well completions in the Permian reached a six-month high in September, and the number of drilled but uncompleted (DUC) wells in the country's most active basin also surged, according to recent data from the US Energy Information Administration's Drilling Productivity Report.

"We maintain our view that takeaway constraints will start to ease materially in [the third quarter of] 2019 thanks to the completion of significant pipeline capacity," analysts at HSBC Research said in a recent research note. "Interestingly, there are signs that these constraints could be tempered earlier as a result of the collective efforts of midstream companies."

PRICE RECOVERY

This trend can also be seen in gas prices at the West Texas Waha Hub.

Cash basis Waha has surged in the past month after prices sank to an all-time low of Henry Hub minus $2.21/MMBtu on September 21, S&P Global Platts data show.

Prices have continued on their recovery, rising to 75 cents/MMBtu on Wednesday, providing some relief to producers after a summer when the surge in supply pressured prices.

Permian gas production has risen to 7.8 Bcf/d after dipping to 7.5 Bcf on October 10.

Analysts said the rise in prices may be the result of the end of intrastate pipeline maintenance creating additional eastbound capacity that may not have been there earlier in October.

-- Eklavya Gupte, **eklavya.gupte@spglobal.com**

-- Edited by Keiron Greenhalgh, **newsdesk@spglobal.com**

Table 3-1: Location, Net Dependable Capacity, Retirement, & Cost Data for all Generating Units - Calendar Year 2017

Southwestern Public Service Company
Location, Net Dependable Capacity, Retirement, & Cost Data for all Generating Units
Year Ended December 31, 2017

Unit Name	Location	Dependable Capacity (MW)	Depreciation Retirement Date	Capital $ (Gross plant)	O&M $ Note (1)	Fuel $ Note (2)	Net Unit Heat Rate (Btu/kWh)	Annual Capacity Factor
Steam Production - Gas/Oil								
Jones Unit 1	Lubbock Co., TX	243	2031	56,505,515	7,781,168	27,525,230	11,725	15%
Jones Unit 2	Lubbock Co., TX	243	2034	42,974,162			11,653	21%
Plant X Unit 1	Lamb Co., TX	41	2019	12,936,222	5,177,841	19,237,688		0%
Plant X Unit 2	Lamb Co., TX	90	2020	24,622,309			13,209	8%
Plant X Unit 3	Lamb Co., TX	93	2024	18,855,781			10,325	10%
Plant X Unit 4	Lamb Co., TX	191	2027	35,719,494			11,502	19%
Steam Production - Gas								
Cunningham Unit 1	Lea Co., NM	73	2019	17,959,658	6,368,910	24,723,641	11,926	21%
Cunningham Unit 2	Lea Co., NM	183	2025	35,112,060			10,826	32%
Maddox Unit 1	Lea Co., NM	112	2028	26,215,290	2,758,834	13,598,149	11,192	38%
Nichols Unit 1	Potter Co., TX	112	2022	25,135,111	6,564,463	18,615,269	12,162	13%
Nichols Unit 2	Potter Co., TX	112	2023	26,429,204			12,349	9%
Nichols Unit 3	Potter Co., TX	250	2030	43,879,171			12,639	9%
Steam Production - Coal								
Harrington Unit 1	Potter Co., TX	342	2036	164,388,476	20,746,232	82,992,794	10,897	43%
Harrington Unit 2	Potter Co., TX	357	2038	176,463,752			10,737	53%
Harrington Unit 3	Potter Co., TX	346	2040	182,861,633			10,519	55%
Tolk Unit 1	Bailey Co., TX	537	2042	318,411,848	18,533,025	97,553,785	10,441	56%
Tolk Unit 2	Bailey Co., TX	541	2045	356,579,357			10,156	53%
Turbine - Gas								
Cunningham Unit 3	Lea Co., NM	106	2040	39,770,605		8,914,831	11,854	10%
Cunningham Unit 4	Lea Co., NM	106	2040	32,503,867			11,149	15%
Maddox Unit 2	Lea Co., NM	61	2025	14,652,207		765,907	13,498	2%
Jones Unit 3	Lubbock Co., TX	168	2056	83,000,136		8,027,899	10,708	7%
Jones Unit 4	Lubbock Co., TX	168	2058	83,299,451			9,312	7%
Turbine - Fuel Oil								
Quay	Hutchinson Co, TX	17	2034	26,534,227	245,846	78,346	20,970	0%

Note (1) The O&M $ are reported by plant
Note (2) Fuel $ is measured at the plant level
Note (3) Retirement dates are reflective of the book depreciation life