SOAH DOCKET NO. 473-19-6677
PUC DOCKET NO. 49831

APPLICATION OF SOUTHWESTERN PUBLIC SERVICE COMPANY FOR AUTHORITY TO CHANGE RATES	§ § §	**BEFORE THE STATE OFFICE OF ADMINISTREATIVE HEARINGS**

REDACTED VERSION

Direct Testimony of Devi Glick

On Behalf of

Sierra Club

February 10, 2020

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DG-16: Gheorghiu, Iulia. Cleco, "SWEPCO shift coal plant use, target 2.8 GW renewables in latest resource plans." Utility Dive (Sept. 6, 2019).

DG-17: Daniel, Joseph. "Seasonal Shutdowns: How Coal Plants that Operate Less Can Save Customers Money." Union of Concerned Scientists (Dec. 20, 2018).

DG-18: *In the Matter of the Application of Pub. Serv. Co. of Colo. for Approval of its 2016 Electric Resource Plan*, Xcel Energy, 2016 Electric Resource Plan, 2017 All Source Solicitation 30-Day Report (Public Version), Colo. P.U.C. Proceeding No. 16A-0396E (Dec. 28, 2017).

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1. INTRODUCTION AND PURPOSE OF TESTIMONY

Q Please state your name and occupation.

A My name is Devi Glick. I am a Senior Associate at Synapse Energy Economics, Inc. My business address is 485 Massachusetts Avenue, Suite 3, Cambridge, Massachusetts 02139.

Q Please describe Synapse Energy Economics.

A Synapse is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Synapse's clients include state consumer advocates, public utilities commission staff, attorneys general, environmental organizations, federal government agencies, and utilities.

Q Please summarize your work experience and educational background.

A At Synapse, I conduct economic analysis and write testimony and publications that focus on a variety of issues related to electric utilities. These issues include, non-exhaustively, power plant economics, utility resource planning practices, valuation of distributed energy resources, and utility handling of coal combustion residuals waste. I have submitted expert testimony on plant economics, utility resource needs, and solar valuation in the states of New Mexico, Connecticut, Virginia, North Carolina, South Carolina, and Florida. I authored a report on replacement analysis for the San Juan Generating Station in northwestern New

Mexico. In the course of my work, I develop in-house models and perform analysis using industry-standard models.

Prior to joining Synapse, I worked at Rocky Mountain Institute, focusing on a wide range of energy and electricity issues. I have a master's degree in public policy and a master's degree in environmental science from the University of Michigan, as well as a bachelor's degree in environmental studies from Middlebury College. I have more than seven years of professional experience as a consultant, researcher, and analyst. A copy of my current resume is attached as Exhibit DG-1.

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of Sierra Club.

Q Have you testified previously before the Public Utility Commission of Texas?

A No, I have not.

Q Have you submitted direct testimony in the simultaneous docketed Case No. 19-00170-UT in New Mexico?

Yes, I submitted direct testimony on behalf of Sierra Club in New Mexico Case No. 19-00170-UT. That New Mexico case is, in many respects, identical to this current Texas case, PUC Docket No. 49831, SOAH Docket No. 473-19-6677.[1]

[1] Texas uses an updated test year that spans July 1, 2018–June 30, 2019. New Mexico uses the historical test year of April 1, 2018–March 31, 2019.

Q What is the status of New Mexico Case No. 19-00170-UT?

A The parties in New Mexico settled that case through an Uncontested Comprehensive Stipulation, executed on January 13, 2020, and submitted for consideration and approval by the New Mexico Public Regulation Commission. Sierra Club was party to the unanimous settlement. The Comprehensive Stipulation includes three elements associated with the end of life for Southwestern Public Service Company's ("SPS" or the "Company") two-unit Tolk Generating Station ("Tolk"): (1) the settlement sets the date of abandonment and retirement for generating purposes of Tolk Units 1 and 2 at December 31, 2032; (2) it requires SPS to submit by June 2021 a robust analysis of Tolk abandonment and potential means of replacement; and (3) it outlines a two-step process to make the depreciation rates consistent with the abandonment date.[2]

Q Did you submit testimony in support of the Comprehensive Stipulation?

A Yes, I submitted testimony on behalf of Sierra Club in support of the Comprehensive Stipulation. In light of the deteriorating economic outlook for the Tolk units, I believe that the Comprehensive Stipulation, including its December 31, 2032, date for the abandonment and retirement for generating purposes, is in the public interest.

While our analysis in New Mexico shows that a retirement date in advance of 2032 would be even better for ratepayers, we find that the stipulated retirement

[2] *In the Matter of SPS's Application for: (1) Revision of its Retail Rates Under Advice Notice No. 282; (2) Authorization and Approval to Shorten the Service Life of and Abandon its Tolk Generating Station Units; and (3) Other Related Relief*, Uncontested Comprehensive Stipulation, N. M. Pub. Regulation Comm'n Case No. 19-00170-UT at 4-5 (Jan. 13, 2020).

date is an incremental improvement and reasonable outcome that will provide value to ratepayers, in addition to reducing impacts on public health and the environment. In the Comprehensive Stipulation, the Company committed to conducting a full, robust retirement analysis for Tolk between Case 19-00170-UT and its 2021 Integrated Resource Plan ("IRP") to be filed in New Mexico, which could lead to an earlier retirement date, if shown to be prudent. Thus, the stipulation is consistent with the pre-settlement recommendations in my direct testimony in Case 19-00170-UT, and the similar recommendations I will provide in this current case.

Q What is the purpose of your testimony in this proceeding?

A My testimony evaluates SPS's Application as it relates to the Company's request for cost recovery in base rates for its operations and investment at Tolk as well as Harrington Generating Station ("Harrington"), a three-unit coal-fired power plant.

First, in Section 3 of my testimony, I evaluate Tolk and Harrington's respective actual historical economic performances over the past few years. My analysis looks first in Section 3(i) at the plants' overall economics relative to the market, and then in Section 3(ii) more narrowly on an operational basis, by calculating each plant's annual costs and revenues from 2015 through 2019. In doing so, I evaluate the reasonableness of SPS's request to recover ongoing operations and maintenance ("O&M") and capital expenditures. These include certain avoidable costs that stem from the Company's general practice, at least up through November 2018, of choosing to "self-commit" the units, *i.e.*, dispatching the units into the market regardless of the prevailing market price, even when doing so meant the units lost money by operating, as discussed in Section 3(iii).

Next, in Sections 4–6, I evaluate the likely future economic performance of the Tolk and Harrington plants. For the Tolk plant specifically, I focus on the reasonableness of SPS's request for approval to operate both of Tolk's two units seasonally, and in synchronous condenser mode, in an attempt to address the plant's serious water constraints.

Finally, in Section 7, I discuss the problems with SPS's prior Strategist unit retirement analysis. I also describe my recommendations that SPS should perform updated, more comprehensive (and hence more accurate) retirement analysis for both Tolk and Harrington.

Q What documents do you rely upon for your analysis, findings, and observations?

A My analysis relies primarily upon the workpapers, exhibits, and discovery responses of SPS witnesses associated with this proceeding. Additionally, I rely to a limited extent on SPS's public rebuttal testimony filed in the parallel New Mexico rate case, as well as certain external, publicly available documents such as the Southwest Power Pool's ("SPP") 2018 State of the Market Report and U.S. Energy Information Administration ("EIA") data.

2. FINDINGS AND RECOMMENDATIONS

Q Please summarize your findings.

A My primary findings include the following:

1. Tolk has historically been operated and dispatched uneconomically. When it converts to seasonal operation, it will likely continue to operate uneconomically, at an unnecessary cost to ratepayers.

2. Harrington, too, has historically been operating uneconomically and will likely continue to do so.

3. SPS's general practice, through November 2018, of typically deciding to "self-commit" these units in the SPP market—so that they are dispatched even when wholesale prices are lower than what's needed for the units to break even—historically resulted in net uneconomic operations at both Tolk and Harrington at ratepayers' expense.

4. The Company's improved dispatch practices (beginning in about November 2018) appear to have improved net operational performance. However, with fixed and capital costs added in, the units were still net uneconomic relative to the market in 2019.

5. SPS cannot economically procure enough water to operate through the Tolk units' current respective retirement dates of 2042 and 2045.

6. Even if SPS can procure enough water to operate Tolk seasonally, or at a reduced capacity through 2032, the Company has not demonstrated that doing so would be the least-cost option to provide its customers with reliable service.

7. SPS's future operating plan and economic analysis for Tolk does not consider: (1) the risk that the water shortage faced by the plant is more extreme than currently projected, (2) the potential opportunity to sell the water for valuable alternative uses, (3) the impact of water limitations on peak availability, and (4) the possibility of retiring the generating assets at Tolk while operating the synchronous condenser year-round to get the necessary voltage support services.

8. SPS's 2014–2015 unit replacement analysis for Tolk and Harrington relies on outdated demand forecasts and resource cost assumptions. In addition, SPS's analysis fails to consider future capital expenditures that may be necessary to address both current and reasonably possible future environmental regulations.

Q Please summarize your recommendations.

A Based on my findings, I offer the following chief recommendations, listed in order of the discussion that follows later in my testimony:

1. The Commission should disallow inclusion of the uneconomic portion of the requested updated test year O&M expenses at Tolk and Harrington incurred during the months of July 2018 through November 2018 inclusive—prior to when the Company apparently improved its dispatch practices—on the basis of their uneconomic operations stemming from self-commitment decisions in the SPP market. Specifically, the Commission could disallow inclusion of an amount equivalent to the difference between: (1) the cost the Company could have paid to meet customer demand by economically dispatching its units and purchasing energy from the market to serve any remaining demand; and (2) the cost the Company actually paid to self-commit and uneconomically dispatch its units to serve customer demand. To the extent SPS has not provided, in this case, data at a sufficiently granular level to enable calculation, the Commission should order SPS to provide it and take up the issue in a future docket.
2. The Commission should investigate (as some other regulators have) whether costs (including fuel costs) have been improperly passed on to customers due to uneconomic self-commitment and dispatch of Tolk and Harrington.
3. The Commission should cap future capital spending on projects that may be intended to prolong the lives of Tolk and Harrington as generating assets, given the plants' uneconomic performances and the impending water shortages at Tolk.
4. The Commission should require SPS to explore securitization as an option to facilitate an accelerated retirement date while mitigating ratepayer impacts.
5. The Commission should require SPS to perform a full retirement analysis for Tolk, assuming a retirement date earlier than 2025, and to present that analysis in

the Company's next rate case following its completion. This analysis should include sensitivities on the timing of water depletion and incorporate (1) the risk of significant future capital and O&M expenditures on environmental compliance, (2) potential revenue from sale of the water, and (3) unit de-rating to reflect the risk to peak operations as the aquifer becomes depleted. SPS has already committed, as part of its settlement of the parallel New Mexico rate case, to performing an updated and more robust retirement analysis of Tolk as well as Harrington. This analysis will be included in SPS's next New Mexico IRP, due in 2021.

6. The Commission should also require SPS to perform and submit an updated unit replacement study for Harrington as part of its next rate case. This analysis should include the risk of substantial future expenditures (capital as well as any increased O&M) stemming from environmental compliance, as well as the possibility of seasonal operations.

3. SPS HAS BEEN OPERATING ITS COAL PLANTS UNECONOMICALLY SINCE AT LEAST 2015

Q Please summarize this section.

A I start by providing a brief overview of the Tolk and Harrington plants. I then summarize SPS's rate requests regarding historical capital and O&M costs. In Section (i), I evaluate the economics of Tolk and Harrington, and I find that total costs exceeded the cost to procure energy from the market in each year from 2015 through 2019 for both plants. In Section (ii), I evaluate the annual operational performance of Tolk and Harrington from 2015 through 2019. I find that, from 2015 through 2018, variable operational costs alone often exceeded the cost at which SPS could have procured energy from the SPP market, which could have

provided retail customers with less costly (while adequate and reliable) service. In Section (iii), I review SPS's coal plant commitment and dispatch practices more broadly, discuss the implications for ratepayers, and recommend that the Commission disallow inclusion of the uneconomic portion of the requested updated test year O&M expenses incurred at Tolk and Harrington between July 2018 and November 2018 inclusive—*i.e.*, the months before SPS improved its dispatch practices— on the basis of uneconomic operations stemming from self-commitment decisions in the SPP market.

Q Please provide a brief overview of the Tolk Generating Station.

A Tolk consists of two 1980s-era coal-fired units located in Sudan, Texas. Unit 1 is rated at 540 MW and Unit 2 is rated at 542 MW. Although the units were originally estimated to operate for only 35 years—*i.e.*, until 2017 (Unit 1) and 2020 (Unit 2)—the Commission approved extensions of their retirement dates to 2042 and 2045, respectively.[3] Tolk relies exclusively on groundwater from the Ogallala Aquifer for generation cooling. However, as SPS's own testimony in this case emphasizes, the aquifer is currently in serious and irreversible decline.[4] At the current rate of consumption, SPS will not have sufficient economically recoverable water to operate the plant beyond the mid-2020s at the latest.[5]

[3] Direct Testimony of M. Lytal on Behalf of SPS, at 51.

[4] *Id.* at 52.

[5] *Id.* at 54-55.

Q Please provide a brief overview of the Harrington Generating Station.

A Harrington consists of three coal-fired units located northeast of Amarillo, Texas. The plant's units came online between 1976 and 1989. Units 1 and 2 are rated at 339 MW, and Unit 3 is rated at 340 MW. The units currently have Commission-approved retirement dates of 2036, 2038, and 2040, respectively.

Q What are SPS's requests in this rate case for Tolk and Harrington?

A SPS is requesting the following:

1. Inclusion in base rates of O&M costs for the updated test year period July 1, 2018–June 30, 2019 for the operation of Tolk and Harrington;
2. Inclusion in rate base, for the entire Company, of energy supply-related capital expenditures of $25.6 million for Tolk and $24.8 million for Harrington incurred during the 24-month period of July 1, 2017 through June 30, 2019[6] (the Company requests inclusion of associated depreciation expenses and a return on investment as well);
3. A change to Tolk's retirement dates from 2042 for Unit 1 and 2045 for Unit 2, to 2032 for both units; and
4. A switch to the seasonal operation of both Tolk units starting in 2020.[7]

[6] Direct Testimony of M. Lytal on Behalf of SPS at 20; Direct Testimony of M. Lytal on Behalf of SPS, Ex. ML-RR 1, Ex. ML-RR-U2, total Company expenditures including affiliate portion.

[7] *E.g.*, Direct Testimony of M. Lytal on Behalf of SPS at 50.

i. Tolk and Harrington each lost money overall relative to the market from 2015 through 2019

Q What did you find regarding the overall economic performance of the Tolk units?

A Using data provided by SPS, I calculated that the Tolk units incurred net losses relative to the SPP energy market in the years 2015 through 2019.[8] This is based on a comparison of the annual costs of energy production and the annual market revenue for each of the two Tolk units. Table 1 shows that the Tolk units collectively lost at least $14 million relative to the market in each year from 2015 through 2019. This includes annual losses relative to the market as high as $28 million for Tolk Unit 1 alone in 2015. Over the five-year timeframe, the Tolk units combined lost $131 million relative to the market.

[8] All economic analysis on Tolk and Harrington throughout the testimony is expressed in total Company dollars.

Table 1: Net annual revenues of Tolk 1 and 2, 2015-2019 (2019 $Million)

Unit	2015	2016	2017	2018	2019*	Total
Tolk 1	($28)	($15)	($17)	($7)	($9)	($76)
Tolk 2	($1)	($9)	($19)	($21)	($5)	($56)
Total	($29)	($24)	($36)	($28)	($14)	($131)

Source: Workpaper of B. Weeks, SO - _SPS_SCENARIO2_REDUXOPS_2031.xlsx, Exhibit SPS-Sierra Club 1-9(k) and Response to SPS-Sierra Club 1-9(p), Exhibit SPS-Sierra Club 1-9(f) and Exhibit SPS-Sierra Club 1-9(i),Exhibit SPS-Sierra Club 6-1(h)(CD), Exhibit SPS-Sierra Club 6-1(f)(CONF)(CD), Exhibit SPS-Sierra Club 6-1(g)(CONF)(CD), Exhibit SPS-Sierra Club 6-1(j)(CONF)(CD) (see Exhibit DG-2).

* Actual fixed and capital costs were not provided for 2019, so we held those costs constant at 2018 levels.

Q What did you find regarding the overall economic performance of the Harrington units?

A Again, using data provided by SPS, I calculated that the Harrington units also incurred net losses relative to the market in the years 2015 through 2019. Table 2 shows that the three Harrington units lost at least $4 million relative to the market in each year from 2015 through 2019, with combined losses relative to the market as high as $65 million in 2016 alone. Total losses relative to the market over the five-year period were $194 million dollars combined for Harrington's three units.

Table 2. Net annual revenues of Harrington 1-3, 2015-2019 ($Million)

Unit	2015	2016	2017	2018	2019*	Total
Harrington 1	($16)	($24)	($21)	($5)	($4)	($71)
Harrington 2	($21)	($22)	($21)	$2	($0)	($61)
Harrington 3	($23)	($19)	($16)	($4)	$0	($62)
Total	($60)	($65)	($59)	($7)	($4)	($194)

Source: Workpaper of B. Weeks, SO - _SPS_SCENARIO2_REDUXOPS_2031.xlsx, Exhibit SPS-Sierra Club 1-9(k) and Response to SPS-Sierra Club 1-9(p), Exhibit SPS-Sierra Club 1-9(f) and Exhibit SPS-Sierra Club 1-9(i),Exhibit SPS-Sierra Club 6-1(h)(CD), Exhibit SPS-Sierra Club 6-1(f)(CONF)(CD), Exhibit SPS-Sierra Club 6-1(g)(CONF)(CD), Exhibit SPS-Sierra Club 6-1(j)(CONF)(CD) (see Exhibit DG-2).
* Actual fixed and capital costs were not provided for 2019, so we held those costs constant at 2018 levels.

Q Please explain the approach you have taken in your analysis.

A The economic screening analysis presented here provides a snapshot into how the plants are performing in the near term. We compare the Company's revenues earned with the actual capital and operational costs required to keep the plant online in a given year, and we evaluate the utility decision-points for continued investment or retirement. We do not amortize the capital costs, as that would spread the costs out for many years into the future. While that approach would be representative of the way that costs would be amortized for ratemaking purposes, it is not useful for understanding the utility's decision-points.

This analysis is distinct from a present value revenue requirement ("PVRR") analysis. PVRR analysis is useful for evaluating the cost of different scenarios over time, such as scenarios with different retirement dates or replacement resource portfolios. With a PVRR analysis, we would amortize sustaining capital costs over the remaining life of the plant (rather than allocating them to the year they are incurred), capture the associated tax and depreciation expenses, and a rate of return for SPS, and then compare the results across scenarios.

Q Describe how you arrived at the values in Table 1 and Table 2.

A The net revenue values in Table 1 and Table 2 are based on data provided by SPS. This includes data on Tolk and Harrington's respective energy revenues, ancillary services revenues, capacity revenues, fixed O&M costs, variable costs, fuel costs, environmental capital costs, non-environmental capital costs, and property taxes. I calculated annual net revenues by subtracting fixed O&M costs, variable costs, fuel costs, environmental capital costs, non-environmental capital costs, and property taxes from energy revenues, ancillary services revenues, and capacity revenues.

SPS provided some of the data at the unit level. [9] This includes energy revenues, ancillary services revenues, and property taxes.[10] Fixed O&M costs, variable costs, fuel costs, environmental capital costs, and non-environmental capital costs were provided at the plant level.[11] I converted plant-level fuel costs and variable costs using a simple ratio of each unit's annual generation relative to the plant's total annual generation in gigawatt-hours ("GWh").[12] Similarly, I converted plant-level fixed O&M costs, environmental capital costs, and non-environmental capital costs using a ratio of each unit's share of the plant's total capacity in

[9] All of 2019 was provided at the unit-level. This includes generation, VOM, fuel costs, energy revenues and ancillary revenues data, which we aggregated up to the annual level. Exhibit SPS-Sierra Club 6-1(h)(CD), Exhibit SPS-Sierra Club 6-1(f)(CONF)(CD), Exhibit SPS-Sierra Club 6-1(g)(CONF)(CD), Exhibit SPS-Sierra Club 6-1(j)(CONF)(CD) (*see* Exhibit DG-2).

[10] Exhibit SPS-Sierra Club 1-9(k); SPS Response to SPS-Sierra Club 1-9(p) (*see* Exhibit DG-2).

[11] Exhibit SPS-Sierra Club1-9(f); Exhibit SPS-Sierra Club 1-9(i) (*see* Exhibit DG-2).

[12] I relied on annual generation data from the Strategist outputs included as workpapers with witness B. Weeks' Direct Testimony on Behalf of SPS. Specifically, I relied on data from "SO - _SPS_SCENARIO2_REDUXOPS_2031.xlsx".

megawatts ("MW").[13] SPS does not have a capacity market, so no capacity value was provided for the individual units. Instead, I valued capacity at the price SPS models for firm capacity sales according to the Strategist model output.[14]

Q Please explain why it is reasonable to value Tolk and Harrington's capacity at the price SPS models for firm capacity sales.

A I selected this price SPS models for firm capacity sales for two reasons. First, this is the value that SPS uses to represent its own market capacity sales; therefore, it should also be a reasonable proxy for the price that SPS would pay to purchase capacity from the same market.

Second, the value of $9.63/kW-year[15] is comparable to capacity prices in other capacity-constrained wholesale markets, and if anything, significantly overvalues the capacity of Tolk and Harrington. For comparison, in MISO's most recent Planning Resource Auction, capacity prices cleared at 2.99/MW-day or 1.09/kw-year for non-capacity constrained regions, and $24.30/MW-day or 8.87/kW-year for Zone 7, which is allegedly capacity constrained.[16] SPP is not currently capacity constrained. Therefore, the $9.63/kW-year equivalent that SPS models is actually a very high assumption for the value for the current non-capacity-

[13] Source of unit-level capacity data: https://www.xcelenergy.com/energy_portfolio/electricity/power_plants/harrington and https://www.xcelenergy.com/energy_portfolio/electricity/power_plants/tolk.

[14] Workpaper of B. Weeks, SO - _SPS_SCENARIO2_REDUXOPS_2031.xlsx. SPS assumes that 200 MW of capacity is available for sale into the market during the four summer months.

[15] Calculations based on SO - _SPS_SCENARIO2_REDUXOPS_2031.xlsx.

[16] Exhibit DG-3, 2019/2020 Planning Resource Auction (PRA) Results, MISO (April 12, 2019), *available at:* https://cdn.misoenergy.org/20190412_PRA_Results_Posting336165.pdf.

constrained region, but it could reasonably represent the value of capacity after multiple units are retired.

Q Why is it inappropriate to use the Cost of New Entry ("CONE") to value Tolk and Harrington's capacity?

A As discussed above, SPS is not capacity constrained; therefore, the value of capacity should not be anywhere near the cost to build a new combustion turbine unit ("CT"). If SPS were to represent the value of capacity at the cost of a new CT (100% of CONE), that value could be $50/kW-year or higher. Additionally, Tolk and Harrington are baseload plants; therefore, it would dramatically overstate the replacement cost of Tolk and Harrington to assume the replacement of 2,000 MW of baseload capacity with the cost of expensive peaking units, such as a CT.

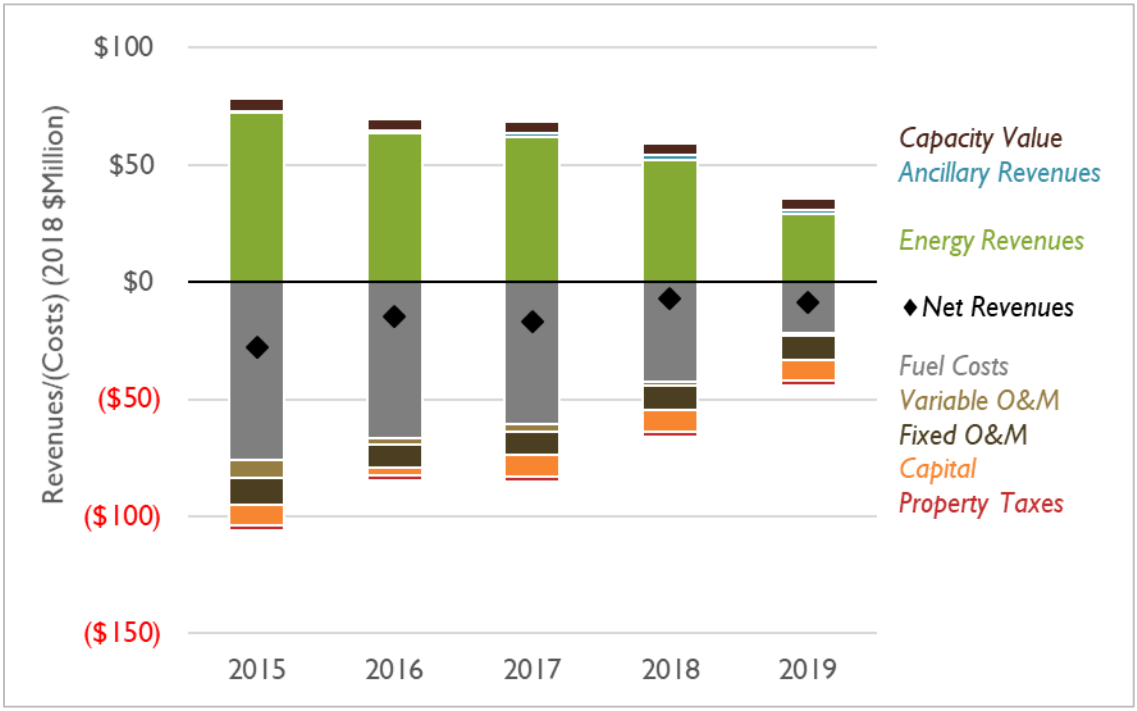
Q Would the retirement and removal of the energy associated with the Tolk and Harrington units have an impact on energy market prices?

A Yes, the removal of each unit would have an impact on energy market prices. However, there are many factors that impact market prices, including fuel price forecasts, and cost and quantity of other resources coming available. You can't make any sort of definitive projections without market simulation modeling. However, it is important to remember that we are not talking about retiring all 2,000 MW of capacity for both plants all at once, but rather each 300 MW and 500 MW unit individually. SPS has significant surplus capacity, so the impact on energy market prices of retiring an individual unit will likely be relatively small. Additionally, as explained above, we are conservatively using a high capacity value to capture the impact that retiring multiple units could have on the value of capacity to the utility.

Q Is it possible to present the results from Table 1 and Table 2 above to show each cost and revenue component of your analysis?

A Yes. Figure 1 and Figure 2 present the results of the historical analysis for Tolk 1 and Harrington 1 with each cost and revenue component shown separately, including the capacity value discussed above. The results for Tolk 2, Harrington 2, and Harrington 3 show a similar pattern. Because they are so similar, I do not produce them here due to space considerations. Figure 1 and Figure 2 illustrate that, in many years, the units' annual fuel costs alone approach or exceed the units' annual revenues.

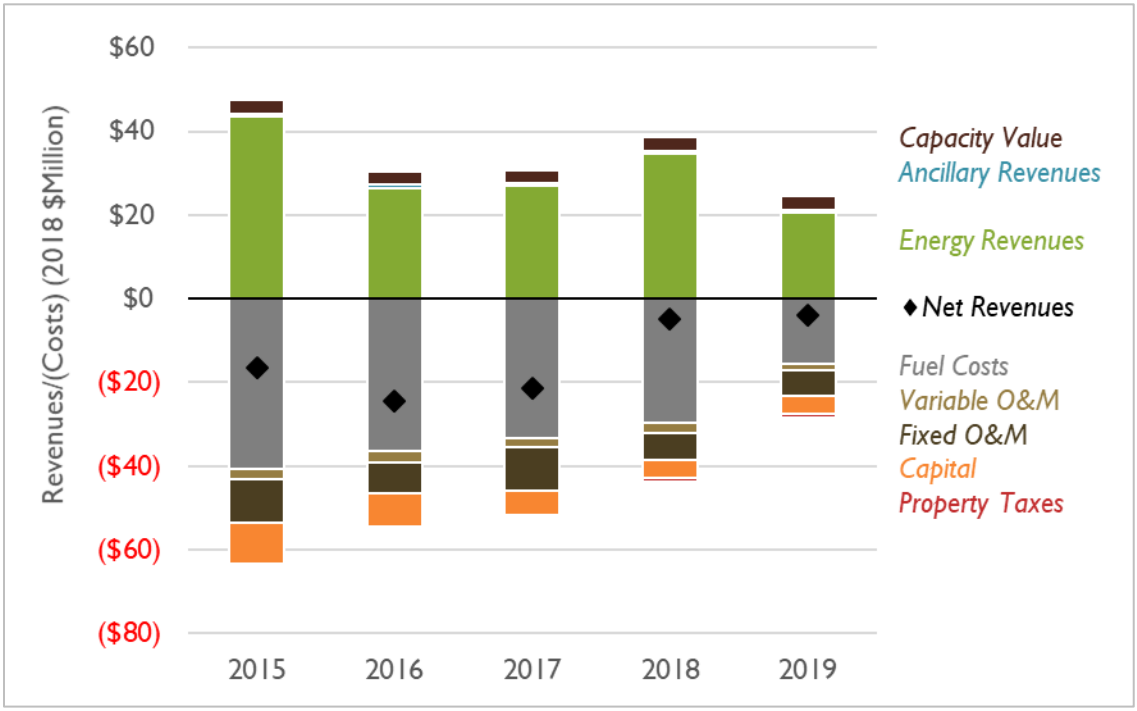
Figure 1. Annual net revenues of Tolk 1, 2015-2019



Source: Workpaper of B. Weeks, SO - _SPS_SCENARIO2_REDUXOPS_2031.xlsx, Exhibit SPS-Sierra Club 1-9(k), Response to SPS-Sierra Club 1-9(p), Exhibit SPS-Sierra Club 1-9(f), Exhibit SPS-Sierra Club 1-9(i)), Exhibit SPS-Sierra Club 6-1(h)(CD), Exhibit SPS-Sierra Club 6-1(f)(CONF)(CD), Exhibit SPS-Sierra Club 6-1(g)(CONF)(CD), Exhibit SPS-Sierra Club 6-1(j)(CONF)(CD) (see Exhibit DG-2).

* Actual FOM and capital costs were not provided for 2019; we held these costs constant at 2018 levels.

Figure 2. Annual net revenues of Harrington 1, 2015-2019



Source: Workpaper of B. Weeks, SO - _SPS_SCENARIO2_REDUXOPS_2031.xlsx, Exhibit SPS-Sierra Club 1-9(k), Response to SPS-Sierra Club 1-9(p), Exhibit SPS-Sierra Club 1-9(f), Exhibit SPS-Sierra Club 1-9(i),Exhibit SPS-Sierra Club 6-1(h)(CD), Exhibit SPS-Sierra Club 6-1(f)(CONF)(CD), Exhibit SPS-Sierra Club 6-1(g)(CONF)(CD), Exhibit SPS-Sierra Club 6-1(j)(CONF)(CD) (see Exhibit DG-2).
* Actual fixed and capital costs were not provided for 2019, so we held those costs constant at 2018 levels.

Q Would SPS be justified in keeping a unit online that was operating at an average annual loss relative to the market over multiple years?

A No. As I will discuss in the next section, SPS could be justified in operating Tolk or Harrington at a loss relative to the market on an hourly, daily, or potentially monthly basis in order to meet peak demand, or conceivably for reliability reasons. However, it is not reasonable to operate a plant for months on end or years at a time, and pass the associated costs on to ratepayers, if the operator cannot earn enough revenue from the market to cover the costs to operate and

maintain the plant. To justify operation, generation resources should, on average, be able to earn enough per kilowatt-hour from the market to cover the variable operations costs, plus a small amount each towards the fixed and capital costs needed to maintain the plant. Otherwise, the Company could more economically procure energy for its customers from the market.

Q Do your findings regarding the recent net losses incurred by SPS's coal units indicate that the Company should retire all five of those units immediately?

A No. There are likely sound logistical and reliability-related reasons to not retire SPS's entire coal fleet at once. In addition, retiring one or more coal units may improve the economics of the remaining coal units. Also, past losses relative to the market are not a guarantee of future losses relative to alternative resource options. Given the recent net losses of SPS's coal units relative to the market, however, the Company should conduct rigorous economic assessments of near-term retirement dates for each of those units, taking into account the relative impact of one or more unit retirements on the remaining units in SPS's portfolio.[17]

[17] As an example, see PacifiCorp 2019 IRP, Appendix R – Coal Studies, *available at:* https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019_IRP_Volume_II_Appendices_M-R.pdf.

ii. Tolk and Harrington often have not earned enough revenue even to cover variable operational costs

Q Please explain the purposes of this section, including the difference between its analysis and the analysis above in Section (i).

A In Section 3(i), I reviewed the total cost to operate and maintain Tolk and Harrington[18] relative to procuring energy from the market. That analysis evaluated the combination of variable operational costs, fixed costs, and capital costs, and then compares the total cost to keep the plant online to the cost of procuring energy, capacity, and ancillary services from the market. That type of analysis, including the accounting for fixed and capital costs, is relevant for evaluating whether SPS's ratepayers will be best served by (1) the Company continuing to invest in a unit and operating it to serve customer needs, or (2) the Company stopping all capital investment in the unit and developing a near-term plan to retire the unit and replace the needed energy, capacity, and grid services.

In this section, by contrast, I review only the variable operations costs (including fuel)[19] and evaluate whether the plant is recovering, through energy market revenues, the incremental cost to operate the unit each hour. I do not include capital and fixed costs, or capacity value. This type of analysis is relevant for evaluating the reasonableness of the plant's dispatch practices, and it sets up evaluation of the prudence of SPS choosing to self-commit the units into the wholesale energy market and recovering O&M costs associated with imprudent dispatch behavior. I discuss this further in Section 3(iii), below.

[18] This cost is sometimes referred to as the long-run marginal cost.

[19] This cost is sometimes referred to as the short-run marginal cost.

Q Please summarize your findings regarding the operational economic performance of the Tolk units in the years from 2015 through 2019.

A Using data provided by SPS, I calculated that each of the Tolk coal units incurred net operational losses relative to the market in multiple years from 2015 through 2018 (Table 3). Net operational losses result when the sum of the hourly fuel and variable O&M costs over a given year are greater than the sum of the hourly nodal locational marginal prices ("LMPs") during all hours the unit is generating energy. Combined, these two units experienced annual net operational losses over half of the time, from 2015 through 2018, with the highest annual net operational loss of $10 million occurring in 2015 at Tolk 1. By contrast, in 2019, SPS's net operational revenues for the Tolk units were positive due to a combination of high natural gas and market prices, and an improvement in the Company's dispatch practices, discussed in Section 3(iii) below.

Table 3. Annual net operational revenues of Tolk 1 and 2, 2015-2019 (2018 $Million)

Unit	2015	2016	2017	2018	2019	Total
Tolk 1	($10)	($4)	($0)	$10	$7	$2
Tolk 2	$17	$2	($3)	($4)	$11	$23
Total	$6	($3)	($3)	$6	$19	$25

Source: Workpaper of B. Weeks, SO - _SPS_SCENARIO2_REDUXOPS_2031.xlsx, Exhibit SPS-Sierra Club 1-9(k) and Response to SPS-Sierra Club 1-9(p), Exhibit SPS-Sierra Club 1-9(f) and Exhibit SPS-Sierra Club 1-9(i), Exhibit SPS-Sierra Club 6-1(h)(CD), Exhibit SPS-Sierra Club 6-1(f)(CONF)(CD), Exhibit SPS-Sierra Club 6-1(g)(CONF)(CD), Exhibit SPS-Sierra Club 6-1(j)(CONF)(CD) (see Exhibit DG-2).

Q Please summarize your findings regarding the operational economic performance of the Harrington units in the years from 2015 through 2019.

A Using the same data provided by SPS discussed above, I calculated that each of the Harrington coal units incurred annual net operational losses in multiple years from 2015 through 2018. Table 4 shows that each of the Harrington units incurred

aggregate operational losses of more than $7 million from 2015 through 2018. Together, the units incurred net operational losses of $35 million from 2015 through 2018. This means that customers would have saved money over this time period if SPP had purchased energy from the market rather than operating its coal units. In 2019, like with Tolk, net operational revenues were positive for the Harrington units due to a combination of high natural gas and market prices, and an apparent improvement in the Company's dispatch practices, discussed in Section 3(iii) below.

Table 4. Annual net operational revenues of Harrington 1, 2, and 3, 2015-2019 (2018 $Million)

Unit	2015	2016	2017	2018	2019	Total
Harrington 1	$1	($12)	($8)	$3	$4	($11)
Harrington 2	($4)	($9)	($7)	$11	$8	($1)
Harrington 3	($5)	($6)	($3)	$4	$8	($1)
Total	($7)	($27)	($18)	$18	$21	($14)

Source: Workpaper of B. Weeks, SO - _SPS_SCENARIO2_REDUXOPS_2031.xlsx, Exhibit SPS-Sierra Club 1-9(k) and Response to SPS-Sierra Club 1-9(p), Exhibit SPS-Sierra Club 1-9(f) and Exhibit SPS-Sierra Club 1-9(i), Exhibit SPS-Sierra Club 6-1(h)(CD), Exhibit SPS-Sierra Club 6-1(f)(CONF)(CD), Exhibit SPS-Sierra Club 6-1(g)(CONF)(CD), Exhibit SPS-Sierra Club 6-1(j)(CONF)(CD) (see Exhibit DG-2).

Q Describe how you arrived at the values in Table 3 and Table 4.

A I arrived at the net operational revenue values in Table 3 and Table 4 by subtracting each of the Tolk and Harrington units' 2015–2019 variable O&M costs and fuel costs from its energy revenues and ancillary services revenues. Each of these costs and revenues were directly provided by SPS, as described in Section 3(i).[20]

[20] SPS provided 2019 hourly data that we aggregated up to the annual level to calculate the 2019 results.

iii. SPS's decision, through November 2018, to self-commit its units resulted in the uneconomic operation of Tolk and Harrington, at avoidable expense to ratepayers

Q Please provide a summary of this section.

A In this section, I discuss some of the decisions and dynamics underlying the annual net operational losses identified in Section 3(ii). Specifically, I discuss the Company's dispatch practices, and I show how SPS's operational decision-making is biased in favor of running its coal units to generate energy rather than serving its load with energy available at lower cost in the market. SPS's decisions to "self-commit" its coal units in the SPP market to serve load has resulted in higher costs to ratepayers.

Q How has SPS described its unit-commitment practices?

A SPS asserts that "under most market operating conditions, SPS offers the Tolk and Harrington units into the SPP Integrated Market ("IM") in "market status" which allows the SPP IM to economically commit and dispatch the units according to market needs." SPS further indicates that it will "'self-schedule' Tolk and Harrington units under certain conditions…"[21] As a matter of fact, however, most of the time—at least until November 2018—SPS did *not* offer the Tolk or Harrington units in market status (by which the Company presumably

[21] SPS Response to Sierra Club 3-4 (*see* Exhibit DG-2). "SPS will 'self-schedule' Tolk and Harrington units under certain conditions such as required environmental emissions testing, unit performance testing, coal bunker management for safety purpose, and to ensure adequate reserve margins for system reliability under high demand and adverse weather conditions that jeopardize the renewable energy production; such as extreme hot or cold weather, icing, wind over speed, cold and hot temperatures cut outs of the wind turbines and potential impacts to natural gas supplies for the SPS generating fleet."

means to suggest 'Economic' status) as illustrated below. The Company offers no clear explanation for the discrepancy between how it describes those past dispatch practices and how it actually dispatched its units during that timeframe.

Q What does your analysis show about how SPS typically operated its coal units in the SPP market?

A My analysis shows that, through November 2018, SPS operated its coal units in the SPP energy market with the units' commitment statuses set to "Self-Commit" most often, and "Economic" or "Outage" each less often. When a unit is set to "Self-Commit" status, a utility decides in advance that it will operate the unit at its minimum operational level or higher regardless of market prices. Conversely, when a unit is set to "Economic" status, the utility is indicating that it will only operate the unit if it is selected based on the day-ahead market results. This means that the utility bids in the price to operate the unit, based on its variable and fuel costs in each hour, and the unit is selected if the bid price is lower than the bid price of the marginal unit (the last unit needed to meet demand in that hour).

Table 5 shows that each of Tolk's two units was set to Self-Commit for at least 60 percent of the hours in each year from 2016 through 2018, and in some years considerably more. For Harrington, Table 6 shows that, on average from 2016 through 2018, each of the three units was set to Self-Commit for nearly 50 percent of the hours (in the case of Harrington 2, substantially more).

Table 5. Tolk commitment practices, 2016-2019 CONFIDENTIAL

Commit Status	Unit	2016	2017	2018	2019*	Average 2016-2018	Average 2016-2019
Economic	Tolk 1	4%	28%	2%	75%	11%	27%
	Tolk 2	13%	21%	2%	71%	12%	27%
Outage	Tolk 1	12%	10%	18%	7%	13%	12%
	Tolk 2	8%	17%	34%	3%	20%	15%
Reliability	Tolk 1	0%	0%	0%	0%	0%	0%
	Tolk 2	0%	0%	0%	1%	0%	0%
Self Commit	Tolk 1	84%	62%	80%	18%	75%	61%
	Tolk 2	79%	62%	64%	25%	68%	58%

Source: Exhibit SPS-Sierra Club 3-2(b)(CONF)(CD),Exhibit SPS-Sierra Club 6-1(d) (CONF)(CD) (see Exhibit DG-2).
*SPS asserts that the Company changed its dispatch practices in November 2018.

Table 6. Harrington commitment practices, 2016-2019 CONFIDENTIAL

Commit Status	Unit	2016	2017	2018	2019*	Average 2016-2018	Average 2016-2019
Economic	Harrington 1	10%	64%	36%	58%	37%	41%
	Harrington 2	4%	6%	14%	79%	8%	22%
	Harrington 3	10%	46%	50%	77%	35%	44%
Outage	Harrington 1	21%	5%	12%	32%	13%	17%
	Harrington 2	12%	14%	3%	10%	10%	10%
	Harrington 3	10%	5%	24%	6%	13%	12%
Reliability	Harrington 1	0%	0%	5%	0%	2%	1%
	Harrington 2	0%	0%	0%	0%	0%	0%
	Harrington 3	0%	0%	0%	0%	0%	0%
Self Commit	Harrington 1	69%	31%	46%	10%	49%	41%
	Harrington 2	84%	80%	82%	12%	82%	68%
	Harrington 3	81%	49%	25%	17%	52%	45%

Source: Exhibit SPS-Sierra Club 3-2(b)(CONF)(CD),Exhibit SPS-Sierra Club 6-1(d) (CONF)(CD) (see Exhibit DG-2).
*SPS asserts that the Company changed its dispatch practices in November 2018.

Q Did SPS recently change its coal unit dispatch practices?

A Yes. Company witness Grant explained in his rebuttal testimony in New Mexico case 19-00170-UT that SPS has "been making continual improvements in how it interacts with the market."[22] Specifically, Grant explains that, as a result of the changes: "SPS has transitioned its dispatch of the coal units to be submitted as market status more than 80% of the time since November, 2018 which is a significant change to how SPS dispatched the units in the early stages of the market."[23]

Q Were you able to verify SPS's claim that the Company has improved its dispatch practices?

A Yes, I was able to verify this claim by updating the dispatch analysis I performed for the New Mexico docket with the Company's 2019 data. As shown in Table 5 and Table 6, I find that SPS did in fact significantly reduce the frequency with which the Company self-committed its coal units into the market.

Q Was the Company operating its coal plants with the improved dispatch practices for the entire updated test year period?

A No. The Company's statement that it "improved" its dispatch practices starting in November 2018 implicitly acknowledges that the previous practices were suboptimal. Improving dispatch practices is a positive step going forward. However, part of the test year period considered in this docket (July – November

[22] Rebuttal Testimony of W. Grant on Behalf of SPS, N.M. Pub. Regulation Comm'n Case No. 19-00170-UT at 36-27 (Dec. 20, 2019).

[23] *Id.*

2018) includes months prior to this "improvement" in dispatch practices. This means that SPS is still proposing to set rates based on a test year that includes four to five months of uneconomic dispatch cost stemming from self-commitment decisions.

Q Describe how you arrived at the values in Table 5 and Table 6.

A I relied on unit-level hourly commitment status data provided by SPS to arrive at the values shown in Table 5 and Table 6. For each unit, I calculated the total number of hours of data provided for each year, and the number of hours each unit's commitment status was set to Economic, Outage, Reliability, and Self-Commit. Finally, I divided the hours for each commitment status by total hours of data to arrive at the percentage of hours that each unit was set to a given commitment status.

Q Do you have concerns with SPS's commitment practices?

A Yes. SPS's claim that it offers Tolk and Harrington in market status under most operating conditions is not supported by the Company's own dispatch record, in which the Company historically designated the units with a Self-Commit status in the majority of hours (see Table 5 and Table 6).[24] In the past, when natural gas prices were higher and renewable prices were still coming down, the coal units may have actually been earning enough revenue to cover their operational costs during a majority of hours (note this does not mean that the units were covering their fixed and capital costs, and were therefore overall economic to operate). In this context, applying a Self-Commit status would not have had as large an impact

[24] Exhibit SPS-Sierra Club 3-2(b)(CONF)(CD) (*see* Exhibit DG-2).

on market conditions as it would today. However, the modern market environment is driven by persistently low gas prices and greater levels of zero-marginal-cost renewables such as wind and solar. In this context, the coal units are actually uneconomic to operate during a large portion of the year, and SPS's bias in favor of committing and dispatching them has cost ratepayers millions of dollars a year.

Q Have other entities raised concerns about self-commitment in the SPP region?

A Yes. The SPP Market Monitor Unit ("MMU") raised this concern in its 2018 State of the Market report, in which it states: "Self-commitment of generation continues to be a concern because it does not allow the market software to determine the most economic market solution. Furthermore, it can contribute to market uplifts and low prices."[25] The SPP MMU's report further states that it continues to "view reducing self-commitment of generation as a high priority for SPP and its stakeholders as this will enhance market efficiency and improve price signals."[26] In December 2019, the MMU issued a report evaluating self-commitment behavior in the SPP market, and concluding that self-commitment practices distort market signals. SPP further concluded that reducing self-commitment will not only lead to better price signals, but it will "likely help market participants

[25] Exhibit DG-4, Southwest Power Pool - Market Monitoring Unit, *State of the Market 2018* at 5 (May 15, 2019), *available at*: https://www.spp.org/documents/59861/2018%20annual%20state%20of%20the%20market%20report.pdf.

[26] *Id.*

make better short-run and long run decisions," and will "likely lead to ratepayer benefits in the form of cost reduction."[27]

Moreover, public utilities commissions in both Minnesota and Missouri have opened formal dockets to investigate utility self-dispatch practices.[28] Additionally, the Sierra Club recently published a report outlining the problems that self-commitment and uneconomic dispatch pose in wholesale energy markets (known as "ISOs" or "RTOs").[29]

Q Have any of Xcel's subsidiary electric utilities already moved away from self-committing coal units in any other jurisdiction?

A Yes. In Minnesota, Xcel subsidiary Northern States Power Company ("NSP") historically offered its coal generators into the MISO market with a commit status of "must run," a term that corresponds to the self-committed status in SPP market. However, NSP recently updated its bid practices for the Allen S. King Generating Station ("King") and Unit 2 of the Sherburne County Generating Station ("Sherco"). NSP now offers these coal units into the market with a default commit status of "economic" unless reliability issues or operational needs require

[27] Exhibit DG-5, Southwest Power Pool, Self-committing in SPP markets: Overview, impacts, and recommendations (Dec. 2019), *available at* https://spp.org/documents/61118/spp%20mmu%20self-commit%20whitepaper.pdf.

[28] *See* Mo. Pub. Serv. Comm'n, Docket No. EW-2019-0370; Minn. P.U.C., Dockets Nos. E999/AA-17-492 and E999/AA-18-373.

[29] Exhibit DG-6, Fisher, Jeremy, *et al.*, *Playing With Other People's Money: How Non-Economic Coal Operations Distort Energy Markets*, Sierra Club (October, 2019), a*vailable at:* https://www.sierraclub.org/sites/www.sierraclub.org/files/Other%20Peoples%20Money%20Non-Economic%20Dispatch%20Paper%20Oct%202019.pdf.

otherwise. This has resulted in a large reduction in hours run at the King and Sherco units.[30]

NSP has also petitioned the Minnesota PUC to allow it to offer both plants into MISO on only a seasonal basis going forward[31] as a way to save ratepayers money. This pivot from year-round operation in self-commit mode, to seasonal operation in economic commitment mode, implies that Xcel's Minnesota utility has determined that self-commitment no longer makes sense on either a year-round or seasonal basis.

Q Have you conducted any additional analyses that explore the frequency with which SPS operates its units at a loss, beyond the economic analysis presented above in Section 3(ii)?

A Yes. I used data provided by SPS to determine the number and percentage of hours in which each unit operated when the hourly unit-level LMP was less than the unit's variable O&M costs and fuel costs.[32] This analysis is similar to what I presented in Section 3(ii), except here I focus on the frequency of hourly results rather than net annual results. Specifically, I calculated the percentage of annual operational hours in which each unit's fuel costs alone are greater than the unit's LMP. Then I added in each unit's variable O&M costs and calculated the

[30] Exhibit DG-7, *In the Matter of the Petition of Northern States Power Company, d.b.a. Xcel Energy, for Approval of a Plan to Offer Generating Resources into the MISO Market on a Seasonal Basis*, Petition Minn. P.U.C. Docket No. E002/M-19-809 (docket initiated Dec. 20, 2019).

[31] *Id.*

[32] I relied on: hourly unit-level generation data provided in Exhibit SPS-Sierra Club 1-10(a)(CD); hourly unit-level day-ahead LMP data provided in Exhibit SPS-Sierra Club 3-2(i)(CD); unit-level variable O&M costs data provided in Exhibit SPS-Sierra Club 3-2(g)(CONF)(CD), provided at irregular intervals but with at least one unit-level datum per year; and monthly plant-level fuel costs data provided in Exhibit SPS-Sierra Club 1-10(b) (*see* Exhibit DG-2).

percentage of hours where the combined variable and fuel costs exceed the unit's LMP.

Q What did you find about the frequency with which SPS operates the Tolk and Harrington units at a loss?

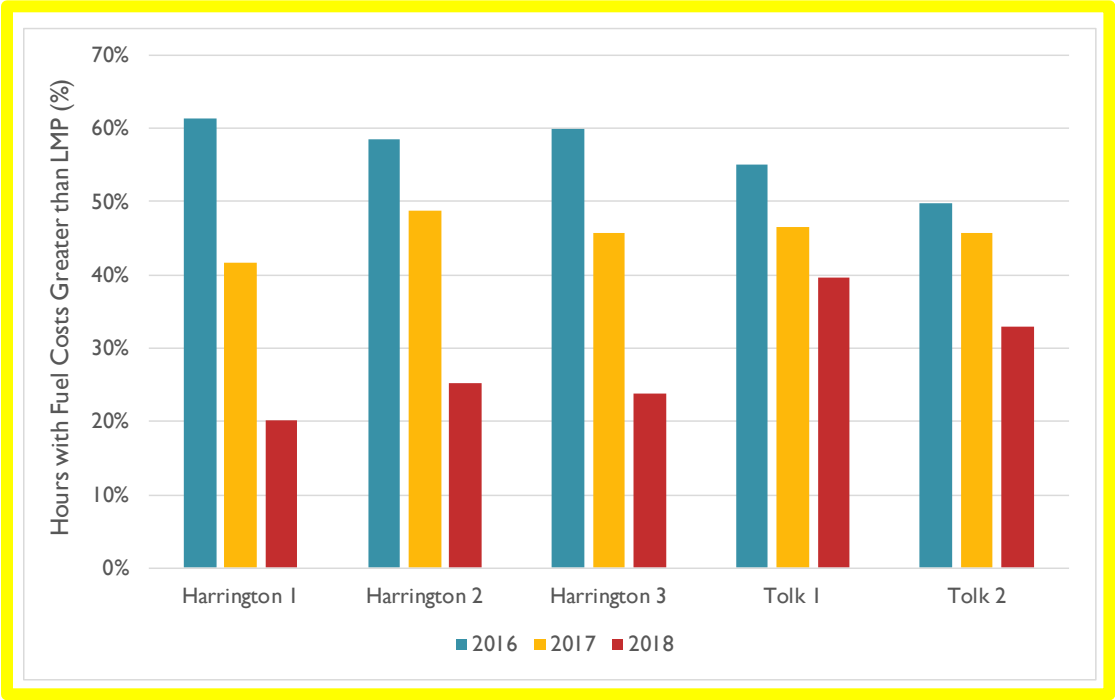
A I found that in 2016 and 2017, for more than 40 percent of the operational hours at Harrington and Tolk, the units' estimated[33] fuel costs were greater than the units' LMP (Figure 3). When I added in the estimated variable O&M costs to the fuel costs, that percentage increased to over 50 percent of the time (Figure 4). Plant performance for both Tolk and Harrington appears to improve in 2018, but this is due in large part to the LMP spike in 2018. There is no reason to believe that LMPs will remain at this level. In fact, the average day-ahead energy prices were 10 percent lower this summer (2019) than they were in the summer of 2018.[34] It is important to note that for Tolk, this slight improvement in 2018 was also concurrent with SPS introducing an Opportunity Cost Calculator (OCC) at Tolk to alter the offer price to reduce dispatch and conserve water.[35] It is concerning that the combination of the OCC and the high LMPs only slightly improved unit performance. This indicates that even when the plant switches to seasonal operations, its fuel and variable costs could still likely exceed its LMPs.

[33] Estimated because fuel costs data was provided on a monthly basis only.

[34] Exhibit DG-8, Southwest Power Pool - Market Monitoring Unit, *State of the Market Report, Summer 2019* at 2 (Oct. 25, 2019), *available at*: https://www.spp.org/documents/60882/spp_mmu_qsom_summer_2019.pdf.

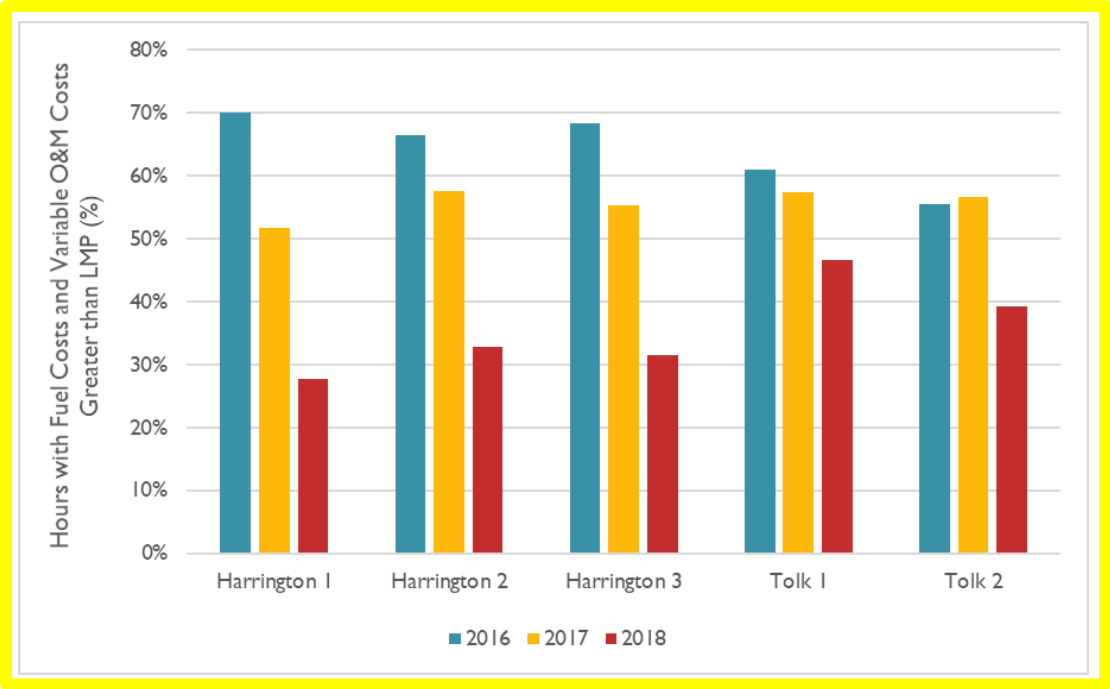
[35] The OCC was introduced in April 2018. SPS Response to Sierra Club 3-1 (*see* Exhibit DG-2).

Figure 3. Percent of operational hours where estimated fuel costs were greater than LMP, 2016-2018 CONFIDENTIAL



Source: Exhibit SPS-Sierra Club 1-10(a)(CD); Exhibit SPS-Sierra Club 3-2(i)(CD); Exhibit SPS-Sierra Club 3-2(g)(CONF)(CD); Exhibit SPS-Sierra Club 1-10(b) (see Exhibit DG-2).

Figure 4. Percent of operational hours where estimated fuel costs plus variable O&M costs were greater than LMP CONFIDENTIAL



Source: Exhibit SPS-Sierra Club 1-10(a)(CD); Exhibit SPS-Sierra Club 3-2(i)(CD); Exhibit SPS-Sierra Club 3-2(g)(CONF)(CD); Exhibit SPS-Sierra Club 1-10(b) (see Exhibit DG-2).

Q Is there a monthly or seasonal trend in uneconomic dispatch by SPS?

A Yes, as shown in Table 7 and Table 8, all units operated uneconomically during a larger portion of the off-peak season hours—namely, October through May—compared to the on-peak season hours—June through September. Below, Table 7 shows the estimated percentage of peak and off-peak season hours when just the units' fuel costs were larger than the units' LMP. Table 8 shows the percentage of peak and off-peak season hours when the units' total variable operational costs, which includes fuel and variable O&M costs, were larger than the units' LMP.

Table 7: Operating hours with fuel costs > LMP (%) by peak season and off-peak season CONFIDENTIAL

Year	Harrington 1		Harrington 2		Harrington 3		Tolk 1		Tolk 2	
	Peak	Off-peak	Peak	Off-peak	Peak	Off-peak	Peak	Off-peak	Peak	Off-peak
2016	48%	69%	47%	65%	48%	65%	39%	63%	39%	56%
2017	29%	53%	30%	59%	31%	55%	28%	57%	29%	57%
2018	16%	23%	19%	28%	15%	29%	29%	46%	32%	34%

Source: Exhibit SPS-Sierra Club 1-10(a)(CD); Exhibit SPS-Sierra Club 3-2(i)(CD); Exhibit SPS-Sierra Club 3-2(g)(CONF)(CD); Exhibit SPS-Sierra Club 1-10(b) (see Exhibit DG-2).

*Note: Peak season is defined as June–September; Off-peak is defined as October–May.

Table 8: Operating hours with total operational costs > LMP (%) by peak season and off-peak season CONFIDENTIAL

Year	Harrington 1		Harrington 2		Harrington 3		Tolk 1		Tolk 2	
	Peak	Off-peak	Peak	Off-peak	Peak	Off-peak	Peak	Off-peak	Peak	Off-peak
2016	53%	80%	52%	74%	54%	75%	43%	70%	43%	63%
2017	42%	61%	42%	66%	43%	63%	44%	65%	45%	65%
2018	26%	29%	30%	34%	26%	35%	36%	53%	39%	39%

Source: Exhibit SPS-Sierra Club 1-10(a)(CD); Exhibit SPS-Sierra Club 3-2(i)(CD); Exhibit SPS-Sierra Club 3-2(g)(CONF)(CD); Exhibit SPS-Sierra Club 1-10(b) (see Exhibit DG-2).

Q Do you know how the magnitude of total operational losses or revenues break down by peak and off-peak season?

A No. We know total annual net operational losses (or revenues), which I presented in Section 3(ii). However, we do not know how those losses break down by season because SPS has not provided data on hourly costs, which Sierra Club

requested.[36] Without these more granular hourly data, we are unable to calculate operational losses by season. To be clear, the data in Table 7 and Table 8 tell us about the estimated *frequency* of uneconomic operation, but not the *magnitude*. This means we do not know if, on the whole, the Tolk and Harrington units are actually covering operational costs during the peak season (but not off-peak season), or if they are uneconomic during both seasons. The Commission should require SPS to produce this information to evaluate the reasonableness of the seasonal operation plan for Tolk, and to help determine whether seasonal operation at Harrington would benefit ratepayers relative to continued full-year operations.

Q What are the implications of this section's findings of uneconomic unit operations and unit commitment decision-making by SPS?

A These results indicate that, during many hours in the three years between 2016-2018,[37] part of which is included in the updated test year, SPS was often committing and dispatching its units in ways that result in net operational losses. This means the plants were not even covering their operational costs, let alone earning enough to cover the fixed and capital costs required to make the plant economic and reasonable to keep online. Moreover, these losses could have been avoided or mitigated by choosing not to offer the units into the SPP market in self-commit status, but rather in economic status—at the least, during the off-peak

[36] Fuel costs were provided as monthly averages, and variable O&M costs were provided for only a few hours per unit for the years 2016 through 2018. Exhibit SPS-Sierra Club 3-2(g)(CONF)(CD); Exhibit SPS-Sierra Club 1-10(b) (*see* Exhibit DG-2). SPS supplemented its response less than a week before the testimony deadline and provided hourly fuel price data. However, this timeline did not permit us to execute and include the required analysis in direct testimony.

[37] These are the historical years for which SPS originally provided data

season. The years with net operational losses represent extreme cases of uneconomic operations (relative to years when the plants cover operational costs, but do not fully cover fixed and capital costs). These findings indicate that SPS was making imprudent unit-commitment and operations decisions. In doing so, the Company was incurring net operational losses that it is seeking to pass on to its retail ratepayers.

Q What are your recommendations to the Commission with regard to SPS's request for O&M for Tolk and Harrington?

A I recommend that the Commission disallow inclusion of a portion of updated test year O&M costs from July 1, 2018, to June 30, 2019, for Tolk and Harrington on the basis that the plants have been, on average, failing to cover even their operational expenses. Specifically, the Commission should disallow inclusion of O&M associated with the units' uneconomic self-commitment dispatch practices prior to the Company's improvement in its dispatch practices sometime in November 2018. To calculate the exact amount to disallow, I recommend that the Commission require SPS to first calculate total operational revenues or losses on a monthly basis for the months of July through November, 2018. For the months with net uneconomic operations, the Commission should not allow inclusion in rates the increment of cost incurred to operate and dispatch the unit that is over and above the cost at which SPS could have purchased energy from the market.[38] This will allow SPS to include in rates only the cost of purchasing energy from the market during the months that SPS was operating the plants uneconomically. SPS has historically been allowed to recover costs associated with uneconomic

[38] Alternatively, the Commission would disallow just the portion of O&M incurred to operate the units during the hours they are operating uneconomically in self-commit mode.

operations from customers, but the Commission now has the opportunity to set rates appropriately and not allow Xcel to continue to saddle ratepayers with irresponsibly incurred costs.

I further recommend that the Commission investigate whether costs have been improperly passed on to customers due to uneconomic self-commitment and dispatch of Tolk and Harrington through a docket dedicated to the issue. At a minimum, the Commission should make clear that it will continue to evaluate the issue in future proceedings, whether in SPS's fuel and/or rate case dockets.

4. TOLK AND HARRINGTON ARE LIKELY TO CONTINUE TO BE UNECONOMIC INTO THE FUTURE, AT UNNECESSARY COST TO RATEPAYERS

Q Please provide a summary of this section.

A In this section I evaluate the likely future economic performance of both Tolk and Harrington using the forward-going cost projections and power prices provided by SPS. First, I calculate projected future net revenues or losses for each unit and find that continued operation of both Tolk and Harrington is likely to result in substantial losses to ratepayers from 2020–2032. Then, to back up these findings, I compare just the Company's projected costs to the revenues that would be required to avoid operating at an economic loss, *i.e.*, "break-even revenues." I compare the results to the historical revenues, and I find that each of Tolk and Harrington's units would need to earn significantly more revenue than each unit has historically to avoid continuing operating at a loss.

Q Why did you conduct your own analysis on the economics of continuing to operate Tolk and Harrington rather than relying on the Strategist results provided by SPS witness Weeks?

A There are several reasons I choose to independently evaluate the economics of continuing to operate the two plants using an economic screening tool.

First, I do not have adequate transparency into SPS's Strategist modeling. It is difficult to assess the reasonableness of cost and operational assumptions with only the annual model outputs that SPS provided in its workpapers. My concerns were validated when we asked for monthly output data, and in the process of preparing our discovery request, SPS realized and subsequently admitted that it had defined the wrong peak months for all of its Strategist runs (and therefore modeled Tolk's seasonal operation incorrectly).[39] This is concerning because no one could have identified this error based on the annual outputs the Company provided with its application. It is therefore possible that the Company made other errors in its Strategist modeling that also cannot be identified from just the annual output data.

Additionally, the scope of the Company's strategist modeling was very limited. SPS did not evaluate whether the Tolk units are operating economically relative to alternatives; nor did SPS identify an optimal retirement date. The analysis was constrained to five specific operational scenarios for the Tolk Plant and did not consider retirement prior to 2025.

[39] Exhibit SPS-Sierra Club 4-1(SUPP1)(*see* Exhibit DG-2) describes the error as "a discrepancy between the summer months as defined in the Direct Testimony of Bennie F. Weeks (June - September), and the summer months modeled in the Strategist analysis (May- September)."

Q Using the data provided by SPS, what can you say about the likely future economic performance of both plants?

A I find that both Tolk and Harrington are very likely to lose ratepayers a substantial amount of money between 2020 and 2032. Specifically, I find that Tolk could lose anywhere between $33 million and $247 million and Harrington could lose between $40 and $554 million total over the time period between 2020 and 2032 inclusive, depending on how often each plant is dispatching during on-peak and off-peak times.[40] Based on the likely scenario that each plant dispatches two-thirds of its monthly generation during on-peak hours, and one-third during off-peak hours (Table 9), I find that Tolk is likely to lose $105 million and Harrington is likely to lose $212 million between 2020 and 2032.

[40] The upper and lower bounds associated with dispatching 100% of generation during on-peak hours or 100% during off-peak hours are not feasible because start-up and shut-down costs would prevent the units from operating in this manner. In reality, a portion of each unit's generation will be dispatched during on-peak hours, and a portion off-peak. The three scenarios are (1) 100% on peak, 0% off peak; (2) 66.6% on peak, 33.3% off peak; (3) 0% on peak, 100% off peak.

Table 9: Projected net revenues (losses) assuming 2/3 of generation is dispatched during on-peak hours and 1/3 during off-peak hours

	2020	2021-2025	2026-2032	Total
Tolk 1	($7)	($21)	$5	($23)
Tolk 2	($12)	($41)	($28)	($82)
Harrington 1	($6)	($40)	($38)	($84)
Harrington 2	($11)	($32)	($23)	($66)
Harrington 3	($5)	($35)	($22)	($62)

Source: SPS response to Sierra Club 1-23; SPS Response to AXM 14-4(CD) "SO - _SPS_SCENARIO2_REDUXOPS_2031_112019.xlsx."; SPS response to Sierra Club 1-26 (see Exhibit DG-2); Exhibit DG-9, SPS response to Sierra Club 4-1(b) Case No. 19-00170-UT

Q Are these results the same as the ones you presented in your direct testimony in New Mexico docket 19-00170-UT?

A No. Three days before the direct testimony filing deadline for intervenors in New Mexico docket 19-00170-UT, SPS identified an error in its Strategist modeling. Specifically, SPS identified "a discrepancy between the summer months, as defined in the Direct Testimony of Bennie F. Weeks (June–September), and the summer months modeled in the Strategist analysis (May–September)."[41] SPS did not provide the corrected workpapers with the Strategist modeling outputs until January 2, 2020.[42]

The analysis I presented in the New Mexico docket 19-00170-UT relied on the outputs from Strategist model runs that erroneously defined the summer peak

[41] Exhibit SPS-Sierra Club 4-1(SUPP1) (*see* Exhibit DG-2).

[42] The Company did not provide the corrected workpapers to intervenors upon discovering the error. Instead, Sierra Club had to file a discovery response to access the corrected results.

months as May through September. The results I present here rely on the outputs from Strategist model runs that corrected the summer peak months as June through September.

Q Please describe how SPS's correction of the discrepancy in the peak month designation impacted your analysis of the projected future performance of the Tolk and Harrington units.

A Using the corrected results, I find that each unit will perform worse (*i.e.*, require greater break-even revenues to recoup its costs) than I previously estimated in my New Mexico testimony using the original data. The discrepancy in the peak month designation by SPS impacts the projected generation levels and forward-going economic performance at the Tolk units, Harrington units, and likely all the Company's other units as well. Our analysis shows that operational costs exceed revenues on a $/MWh basis at both the Tolk and Harrington plants; therefore, a decrease in generation levels at either plant results in a decrease in net operational costs (and vice versa).

The corrected analysis shows lower generation levels at Tolk, therefore the units will require slightly lower break-even revenues than we found using the initial Strategist analysis to cover costs on an annual basis.[43] However, the corrected analysis also shows the Tolk units will operate one additional year (through 2032). By extending operations, the Tolk units will incur a full year of additional costs that must be recouped through revenues. As a result, the total break-even revenues for the Tolk units are greater than previously calculated.

[43] Our analysis shows that operational costs exceed revenues on a $/MWh basis at these plants; therefore, a decrease in generation levels will result in a net decrease in costs.

The corrected analysis shows increased generation at the Harrington units, and therefore these units incur greater costs (fuel, variable O&M, and fixed O&M) than shown in the initial Strategist run. As a result, the Harrington units require higher break-even revenues than previously calculated to cover annual costs.

Q Describe how you calculated the values in Table 9.

A I calculated the forward-going costs the Tolk and Harrington units are projected to incur based on adding together the fuel costs, variable O&M costs, fixed O&M costs, and ongoing capital costs—including the costs to drill additional wells at Tolk (allocated evenly between Units 1 and 2)—provided by Company as a corrected version of witness B.F. Weeks Strategist output files.[44] I then calculated energy revenue using monthly generation data from the Tolk Strategist model[45] and the monthly on- and off-peak power prices provided by SPS for SPP South.[46] I assumed that two-thirds of monthly generation was dispatched during on-peak hours, and one-third was dispatched during off-peak hours.

[44] SPS Response to AXM 14-4(CD) "SO -_SPS_SCENARIO2_REDUXOPS_2031_112019.xlsx." (*see* Exhibit DG-2).

[45] Exhibit DG-9, SPS response to Sierra Club 4-1(b), N.M. Pub. Regulation Comm'n Case No. 19-00170-UT (Jan. 2, 2020).

[46] SPS Response to Sierra Club 1-26 (*see* Exhibit DG-2). SPS provided projected power prices for several locations; however, given the location of Tolk and Harrington in SPP south, I selected the prices for this location.

Q SPS's data seems to indicate that Tolk will become more economic after 2025. Do you think this is accurate and does this support continued operation of the plant?

A No. First, the plant is projected to lose a substantial amount of money relative to the market between now and 2025. Those losses far outweigh the projected net revenues. Second, projected revenues are based on power market price projections that are increasingly uncertain as you get further out. Finally, the Company appears to be understating the costs to maintain access to sufficient water at Tolk based on the Company's recent historical spending on water supply and water availability projects at Tolk. While it is reasonable for SPS to project lower O&M costs when the plant switches to seasonal operation, and to avoid spending on large capital projects as the plant nears retirement, [47] SPS's projection of future capital investments needs to reflect the full likely costs to maintain access to sufficient water. Between 2014 and 2017, SPS spent $11.2 million on water supply and water availability-related capital investments, and the Company has spent an additional $4.9 million since the beginning of 2019. [48] Going forward, SPS projects spending an average of only $1 million annually on water projects at Tolk.[49]

[47] With a switch to seasonal operation, SPS will have to recover the fixed and capital costs over a smaller portion of hours. However, SPS asserts that with a switch to seasonal operation, O&M will be lower and "the interval between [capital] projects can be extended." Further, SPS states that "all capital projects in the later years will be evaluated for the need during managed decline phase of the units." SPS Response to Sierra Club 1-23 (*see* Exhibit DG-2).

[48] SPS Response to Sierra Club 1-24 (*see* Exhibit DG-2).

[49] SPS Response to AXM 14-4(CD) "SO -_SPS_SCENARIO2_REDUXOPS_2031_112019.xlsx."

Q Given the uncertainty about future conditions, have you performed any other analysis to support your findings above?

A Yes. I have also performed break-even analysis to focus on just SPS's projected costs, and the revenue required to cover those costs. The analysis I presented above, comparing projected future costs and revenues for each unit, relies on uncertain power price projections years into the future. This analysis also required me to make a key assumption about when each unit was dispatching. The analysis answers the question, "Based on the power prices and costs provide by the Company, and your assumptions around unit dispatch, what is the likely economic performance of each unit?" The break-even analysis, on the other hand, is based almost entirely on the Company's information and involves minimal additional operational assumptions. It answers the question, "What assumptions about future power prices are needed for the analysis to show positive net revenues, given the Company's assumptions around future costs, in order for the plants to earn net revenues?"

Q What is a break-even analysis?

A A break-even analysis in this context calculates the LMP or the revenue that is required for the plant's revenues to exactly equal its operational costs (fuel and variable O&M) plus recover a share of its long-term costs (fixed and capital). The break-even LMPs can be thought of as the minimum average LMP a unit must receive for generation in order to not lose ratepayers money over the long term. Break-even total revenue can be thought of as the minimum total revenue that a plant must earn in a year, based on the calculated LMPs and the likely projected future generation levels.

Q Please summarize your findings regarding the future economic performance of the Tolk units.

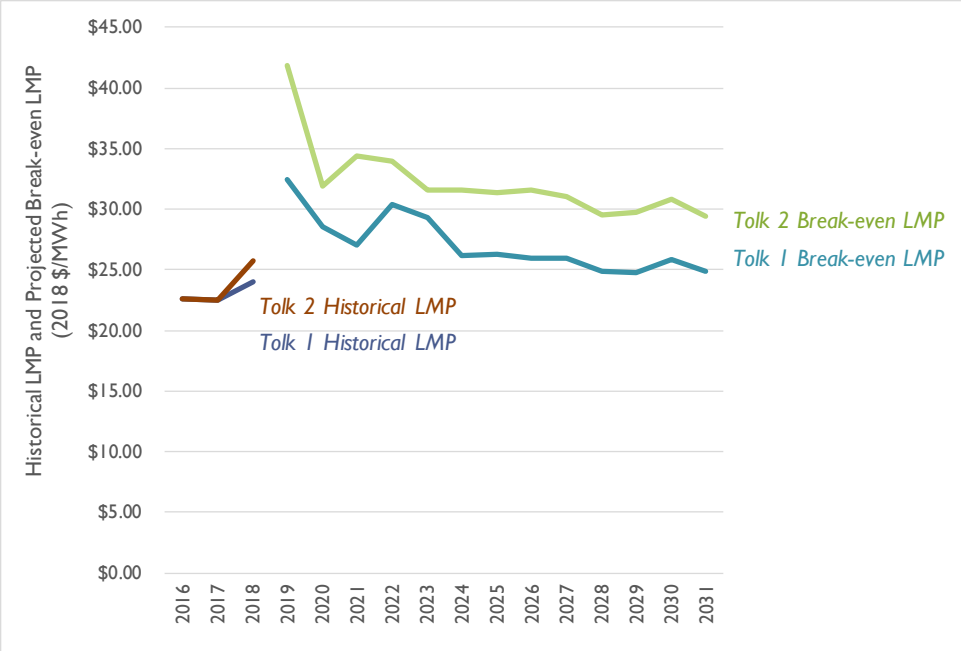
A Using future cost and generation projections provided by SPS,[50] and historical LMPs and generation also from SPS,[51] I find that the Tolk units will need to receive an average LMP that significantly exceeds average LMPs from the recent past (2015–2018) to cover the average cost of keeping the unit online (Figure 5). I present the forward-going costs as the hourly LMP that the Tolk units would need to earn. I compared these projected LMPs to historical annual average hourly LMP for each unit based on hourly unit-level LMPs from the SPP from 2015 through 2018.[52] SPS has presented no evidence or projections that indicate that the Company believes future LMPs will increase to the level required to make sustained operation of Tolk economic.

Additionally, it is important to note that both the difference in break-even LMPs between the two Tolk Units, and the dip in break-even LMPs between 2019 and 2020 shown in Figure 5 result from unexplained assumptions made by the Company in its Strategist modeling. First, SPS models an increase in generation from both Tolk units between 2019 and 2020, and a decrease in fixed costs over this same time. This results in a significant dip in the cost per kWh in 2020 relative to 2019. Second, the Company models higher generation levels and lower

[50] SPS Response to AXM 14-4(CD) "SO -_SPS_SCENARIO2_REDUXOPS_2031_112019.xlsx." (*see* Exhibit DG-2).
[51] SPS response to Sierra Club 1-10(a)(CD), SPS response to Sierra Club 3-2(i)(CD), (*see* Exhibit DG-2).
[52] *Id*.

fixed costs at Tolk 1 than at Tolk 2 over the time period 2020–2032; this results in a higher $/kWh break-even cost at Tolk 2 than at Tolk 1.[53]

Figure 5. Tolk Units 1 & 2 historical and future break-even LMPs, 2015–2032



Source: SPS Response to AXM 14-4(CD) "SO -_SPS_SCENARIO2_REDUXOPS_2031_112019.xlsx."SPS response to Sierra Club 1-10(a)(CD), SPS response to Sierra Club 3-2(i)(CD), (see Exhibit DG-2).

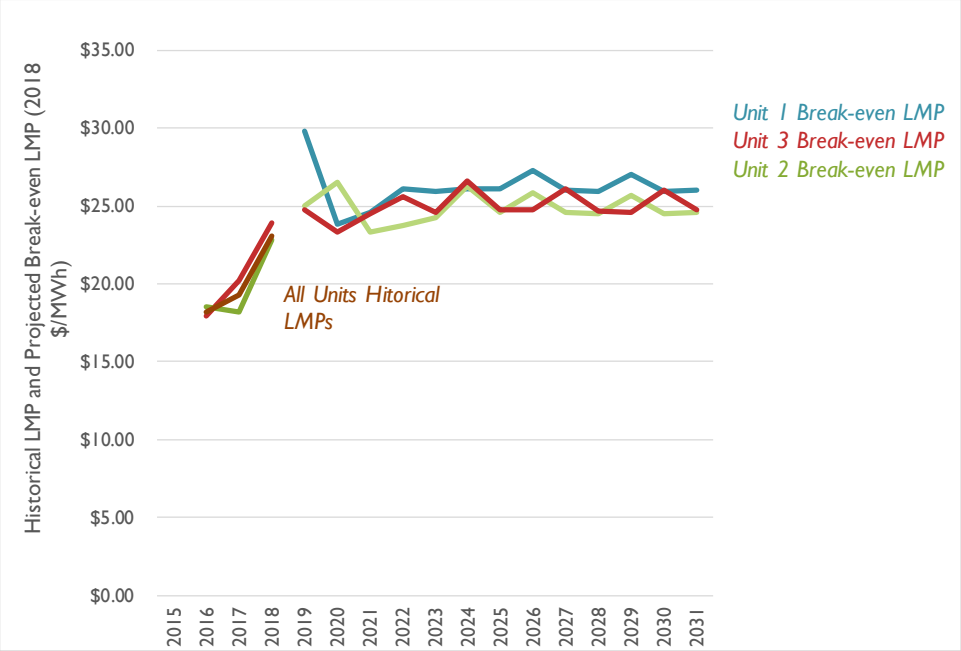
Q Please summarize your findings regarding the future economic performance of the Harrington units.

A Using the same data provided by SPS, I calculated the forward-going costs that the Harrington units are projected to incur through 2032, and therefore the revenues and LMPs that the Harrington units would need to receive to cover their

[53] SPS Response to AXM 14-4(CD) "SO -_SPS_SCENARIO2_REDUXOPS_2031_112019.xlsx." (*see* Exhibit DG-2).

long-term average costs. Figure 6 shows that for the Harrington units to avoid losing ratepayer's money, each unit would need to receive annual average LMPs in most years that exceed the annual historical average LMPs they received from 2015 through 2018. Despite the 2018 spike in SPP energy prices, there is no evidence to support an assumption that future revenues and LMPs will continue to increase to a level required to sustain economic operations. Using past LMPs as a proxy for future LMPs, all three Harrington units would be uneconomic in the majority of years through 2032.

Figure 6: Harrington Units 1–3 historical and future break-even LMPs, 2015–2032



Source: SPS Response to AXM 14-4(CD) "SO - _SPS_SCENARIO2_REDUXOPS_2031_112019.xlsx.",SPS response to Sierra Club 1-10(a)(CD), SPS response to Sierra Club 3-2(i)(CD), (see Exhibit DG-2).

Q Describe how you arrived at the values in Figure 5 and Figure 6.

A I calculated the forward-going costs the Tolk and Harrington units are projected to incur using the same data and methodology outlined in the first part of this

section.[54] I used the projected annual costs for each unit net of the capacity value to estimate the level of annual revenues SPS would have to receive from the ancillary and energy markets in order to break even. That is, if the annual revenues for a unit were exactly equal to the annual costs, the unit would achieve break-even economic status. However, if the annual revenues are less than the annual costs, the unit would be operating at a loss.

Because SPS plans to reduce operations at Tolk and operate the plant only from June through September (peak season) between 2020 and 2032,[55] it is not useful to directly compare forward-going break-even revenues with historical revenues.[56] Instead, I divided the calculated annual break-even revenues by projected generation by unit—provided in SPS's corrected Strategist output files[57]—to arrive at break-even LMPs. For consistency of analysis, I present the results from Harrington as a break-even LMP as well based on year-round operation.

Q Is there other analysis that supports your overall economic assessment of SPS's Tolk and Harrington Stations' forward-going economics?

A Yes. Analysis from SPP's Market Monitoring Unit ("MMU") supports this assessment. The SPP MMU's 2018 *State of the Market* report, which I noted

[54] SPS Response to AXM 14-4(CD) "SO -_SPS_SCENARIO2_REDUXOPS_2031_112019.xlsx." (*see* Exhibit DG-2).

[55] Direct Testimony of B. Weeks at 34.

[56] Due to the reduced operations in the forward-going analysis, forward-going production costs will be lower than historical production costs, and consequently the break-even revenues will be less than historical revenues.

[57] SPS Response to AXM 14-4(CD) "SO -_SPS_SCENARIO2_REDUXOPS_2031_112019.xlsx." (*see* Exhibit DG-2).

earlier, describes coal plant economics within the SPP region and indicates that "…MMU analysis shows that market revenues do not support going forward costs for coal resources."[58]

Q What are the implications of these uneconomic results for ratepayers?

A Based on SPS's own input assumptions, and using two separate types of analysis, I find that Tolk and Harrington are very likely to continue operating at a loss going forward. This means that ratepayers will continue to pay for SPS to uneconomically operate the Company's coal fleet.

Q What are your recommendations to the Commission with regard to any request for recovery of future capital investments at Tolk and Harrington?

A Given that Tolk and Harrington will likely remain uneconomic, I recommend that the Commission place a cap on expenditures intended to prolong the lives of Tolk and Harrington as generating assets, require detailed justification for all spending, and not allow the Company to recover from ratepayers spending in exceedance of the cap. This practice is utilized by other Commissions, notably the Georgia Public Service Commission, and was applied to the Bowen plant in the Company's 2019 IRP docket.[59] It is unreasonable for ratepayers to spend unnecessary money to keep economically non-competitive units online, particularly in light of the impending water shortages at Tolk.

[58] Exhibit DG-4, Southwest Power Pool - Market Monitoring Unit, *State of the Market 2018* at 2 (May 15, 2019), *available at*: https://www.spp.org/documents/59861/2018%20annual%20state%20of%20the%20market%20report.pdf.

[59] Exhibit DG-10, *Georgia Power Company's 2019 Integrated Resource Plan*, Ga. Pub. Serv. Comm'n Docket No. 42310, Order Adopting Stipulation as Amended (July 29, 2019).

5. TOLK CANNOT ECONOMICALLY PROCURE WATER TO OPERATE THROUGH ITS UNITS' CURRENT RESPECTIVE RETIREMENT DATES OF 2042 AND 2045

Q Please summarize this section.

A In this section I review SPS's request to adjust the depreciation dates of the two Tolk units based on a retirement date of 2032, accelerated from the current dates of 2042 for Unit 1 and 2045 for Unit 2. Specifically, I examine the Company's groundwater modeling and economic analysis and find that the modeling and analysis supports the Company's assertion that it cannot economically procure groundwater to maintain operations at Tolk through 2042 and 2045.

Q What is SPS's request regarding future operations of Tolk in this rate case?

A SPS requests the following relief:

- A change to Tolk retirement dates from 2042 for Unit 1 and 2045 for Unit 2, to 2032 for both units, and a switch to seasonal operation starting in 2021.[60]
- A change in the depreciation lives of the Tolk units to 2032 for generating purposes.[61]
- A depreciable life for the assets associated with Tolk's operation in synchronous condenser mode ending in 2055.[62]

[60] Direct Testimony of W. Grant on Behalf of SPS at 77; Direct Testimony of M. Lytal on Behalf of SPS at 50.

[61] Direct Testimony of M. Lytal on Behalf of SPS at 11.

[62] *Id*.

Q Has SPS previously requested a change in the remaining useful life for Tolk?

A Yes, in SPS's last rate case, the Company agreed to update the retirement date for depreciation purposes to 2037. However, SPS did not officially request a 2032 retirement date until this case.[63]

Q Why is SPS requesting a change in the remaining useful life date for Tolk?

A SPS is requesting a change to the retirement date, and plans to switch to seasonal operations at Tolk, due to the "continuing and irreversible decline of the Ogallala Aquifer."[64] SPS asserts that if Tolk continues to operate at current levels, economic depletion of the aquifer will occur between 2024 and 2026. Once economic depletion occurs, the cost to secure water through continued drilling of new wells or alternative procurement measures will make it uneconomic to ratepayers for SPS to continue operating the plant.[65]

Q What alternative solutions has SPS explored to procure the water needed to keep Tolk operating through its original retirement dates of 2042 and 2045?

A SPS explored alternative solutions in the prior rate case; specifically a water pipeline project with the City of Lubbock and the construction of hybrid cooling towers.[66] However, the City of Lubbock notified SPS that it is not able to provide Tolk the required quantity of water, and the construction of two hybrid cooling

[63] Direct Testimony of W. Grant at 77.
[64] Direct Testimony of M. Lytal at 9-10.
[65] *Id.* at 57.
[66] Direct Testimony of W. Grant at 78/79.

towers would be cost prohibitive at around $236 million.[67] Based on this and other assessments, SPS concluded that there is no feasible way to economically operate the Tolk units until the end of the units' currently approved service lives in 2042 and 2045.[68]

Q Has SPS already been facing water supply challenges at Tolk?

A Yes. As the Ogallala Aquifer is depleted and the level of saturated thickness drops,[69] SPS has had to drill an increasing number of wells to supply the water needed for peak operations. Tolk's well count has increased 207 percent since 1992, yet total wellfield production has declined by 25 percent during the same timeframe.[70] SPS hired an external firm, WSP USA, to perform its groundwater modeling. WSP's 2018 groundwater modeling concluded that SPS would have trouble extracting enough water from the wellfield to meet peak demand in the summer starting in 2019.[71]

[67] Company Witness Grant stated "SPS has determined that the installation of hybrid cooling towers at Tolk to be economically imprudent given the age of Tolk, the uncertainty and cost of the technology, and the potential for increased environmental costs that may occur at some point in the future." *Id.* at 78.

[68] Direct Testimony of M. Lytal at 78.

[69] The saturated thickness of the aquifer is defined as the distance from the water table to the base of the aquifer.

[70] At the time Tolk was built, the wellfield average flow was approximately 700 gallons per minute (gpm) per well; now the flow rate is approximately 200 gpm and projected to drop to between 50-80 gpm as the aquifer is further depleted. Direct Testimony of M. Lytal at 62-63.

[71] *Id.* at 62.

Q Has Tolk undertaken any projects recently related to water supply access?

A Yes. Tolk added eight new wells between 2018 and 2019 to offset predicted production deficits from the current wells.[72] SPS acknowledged that the Company will need to continue regularly drilling new wells to sustain operation through 2032.[73]

Q Has SPS presented sufficient evidence to support its assertion that Tolk cannot feasibly maintain operations at current levels through the units currently approved service lives of 2042 and 2045?

A Yes. Based on groundwater data collected for the Company between 2007 and 2018,[74] and the Company's evaluation of alternatives, SPS has presented ample evidence to demonstrate that the costs of obtaining the water required to sustain operation through 2042 and 2045 far exceeds economic levels. In light of the rapidly deteriorating water supply, it is clear that the Tolk units should be retired by 2032 *at the latest*. Indeed, our analysis of the Company's own data makes clear that customers would save money by retiring the plant even sooner. Based on this, I recommend that the Commission approve a retirement (and depreciation) date for Tolk no later than 2032, or ideally earlier.

[72] *Id.* at 65.

[73] *Id.* at 73-74.

[74] Sources included 3-D modeling and other public data from the High Plains Water District ("HPWD"), modeling and data from the United States Geological Survey, semi-annual wellfield productivity test, and groundwater modeling from the firm WSP.

Q What are the utility's options for dealing with an asset such as Tolk that can no longer economically operate through its Commission-approved retirement date?

A There are several things that can happen when a utility realizes it has an asset that is, or will become, uneconomic:[75]

1. The utility continues to operate the asset and invest the capital needed to keep the unit online, even if market signals show that the unit should be replaced with cost-effective alternatives. The utility recovers the costs from ratepayers through an unnecessarily high rate base, and therefore unnecessarily high rates, and through fuel cost recovery dockets.

2. The utility changes operational practices to limit operation in low-value hours. This can include a transition to seasonal operations, switching from self-dispatch to only economic-dispatch in the market, and installation of a synchronous condenser to provide additional value streams during times when the unit it offline. The utility continues to recover the costs to operate the unit from ratepayers.

3. The utility requests an earlier retirement date and an accelerated depreciation schedule (either based on its own analysis or a Commission directive). The depreciation date is moved up (potentially in several stages) to match or at least more closely align with the actual retirement date. Ratepayers may experience rate shock if the Commission allows the

[75] This list is not intended to be exhaustive.

costs of accelerated depreciation to be passed onto ratepayers through an increase in the rate base and an accompanying rate increase.

4. The utility decides to immediately, or in the very near term, retire a plant that is found to be actively losing money (either based on the utility's own analysis or a Commission directive). The asset becomes "stranded" and one of the following can happen: (1) ratepayers are forced to continue to pay for the plant in rate base even though it is providing no value to them (perhaps through an accelerated depreciation schedule); (2) the Commission allows the utility to recover some of the cost of the asset, but may limit the amount of the return collected on it. (3) The asset is completely disallowed from rate base, and shareholders have to absorb the outstanding costs of the plant.

5. The utility securitizes the asset through ratepayer-backed bond securitization. The utility issues customer-backed bonds at low rates (typically under 4 percent—a much lower rate than if it had to raise its own funds from investors to cover the debt) and recovers the costs from ratepayers in their bills each month.[76] The customer is guaranteed savings over traditional recovery and the utility is able to recover the costs of its stranded assets. Additionally, as part of a financing order, the PUC could direct funds to assist communities and workers impacted by the plant retirement. Legislation is required to give the utility authority to issue bonds.

[76] Exhibit DG-11, Varadarajan, Uday, David Posner, Jeremy Fisher, *Harnessing Financial Tools to Transform the Electric Sector*, Sierra Club at 10-11 (Nov. 2018), *available at:*. https://www.sierraclub.org/sites/www.sierraclub.org/files/sierra-club-harnessing-financial-tools-electric-sector.pdf.

Q Please explain more about ratepayer-backed securitization?

A Ratepayer-backed securitization is by no-means a perfect mechanism, but it does address the fundamental misalignment between shareholders and ratepayers and therefore presents a reasonable path forward for shutting down uneconomic coal plants. The mechanisms can also provide value to other stakeholders (such as plant workers and impacted communities) that might otherwise be left out. Specifically, through securitization, "utilities are able to receive a reasonable return on their investments, expensive generation is retired, impacted communities have resources to smooth the transition, and customers benefit from lower costs."[77]

Q Why is securitization a reasonable option for SPS to consider for Tolk?

A It is my understanding that securitization is already legally allowed in Texas for any system costs "incurred by an electric utility . . . in connection with the restoration of service and infrastructure associated with electric power outages affecting customers of the electric utility as the result of any . . . weather-related event."[78] Company witness Lytal asserts that "the depletion of the aquifer has been accelerated by significant regional drought."[79] As Tolk's rapidly deteriorating water supply, and its eventual early retirement, is partially attributed to persistent and severe "weather-related" regional drought, [80] I recommend that the Commission and the Company evaluate the feasibility and benefits of

[77] *Id.*, at 10.

[78] PURA § 36.402(a).

[79] Direct Testimony of M. Lytal at 52. Aquifer depletion is also attributed to agricultural, municipal, and industrial uses.

[80] SPS Response to Sierra Club 5-2 (*see* Exhibit DG-2).

securitization under existing law. Alternatively, SPS should evaluate and pursue legislative changes more broadly to make this option available. Securitization is already allowed in New Mexico under that state's Energy Transition Act ("ETA").[81]

6. SPS HAS NOT DEMONSTRATED THAT SEASONAL OPERATION OF TOLK THROUGH 2032 IS THE LOWEST-COST OPTION FOR SERVING CUSTOMERS' NEEDS

Q Please summarize this section.

A In this section I first explain SPS's proposal to conserve water by operating Tolk seasonally as a generator from 2020 through 2032, and by operating the unit as a synchronous condenser in the off-peak season. I summarize the groundwater modeling and Strategist analysis upon which SPS relied and outline my concerns with the groundwater modeling and economic analysis. Then, in Section (i), I review how the risk of water shortage is incorporated into SPS's water model. In Section (ii), I discuss an alternative use for the water currently used at Tolk. In Section (iii), I outline how water shortages can impact modeling of peak capacity. In Section (iv), I review the Company's Tolk Strategist analysis. Finally, in Section (v), I outline how to incorporate each of the water-related risks and opportunities into the Company's economic analysis.

[81] Morehouse, Catherine, *New Mexico regulators attempt to bypass San Juan securitization, to PNM's surprise*, Utility Dive (July 12, 2019), *available at*: https://www.utilitydive.com/news/new-mexico-regulators-attempt-to-bypass-san-juan-securitization-to-pnms-s/558641/.

Q Please explain SPS's proposed seasonal operation plan at Tolk between now and the proposed retirement date of 2032?

A To conserve the economically recoverable water to which Tolk has access, and to extend the life of the plant to maintain the capacity value of the plant, SPS is proposing to reduce operations seasonally.[82] Between 2019 and 2020, SPS proposes to operate Tolk as a coal-fired generator at full "economic dispatch" between June through September, and to operate the unit only at minimum load in the remaining off-peak months.[83] Then, starting in 2021, SPS proposes to continue full "economic dispatch" operations during the peak months (June–September) and operation in synchronous condensing mode during the off-peak months (October–May).[84]

Q Why does SPS propose to operate Tolk in synchronous condenser mode when it is not operating as a generator?

A Tolk currently provides voltage stabilization to the transmission system when it generates electricity.[85] SPS claims that the regional transmission system will face voltage constraints when Tolk is not generating electricity. Installation of a synchronous condenser and operation in synchronous condenser mode will allow the plant to provide the voltage stabilization SPS asserts is needed without operating the plant in generation mode and consuming fuel.

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[82] Direct Testimony of M. Lytal at 50,69.

[83] Direct Testimony of B. Weeks at 34-35. SPS indicates that because of the time required to install the synchronous condenser, it is not feasible to take Tolk offline during the off-peak months beginning in 2019.

[84] *Id* at 31-32.

[85] Direct Testimony of M. Lytal at 69.

Q What analysis did SPS rely on to develop its strategy to operate Tolk seasonally?

A As noted, SPS relied on 2018 groundwater modeling from the firm WSP to evaluate whether the groundwater supply could roughly meet the required demand for continued operation under both current operations (typical demand) and seasonal operations (optimized demand).[86] Based on the results of this modeling, SPS then developed a spreadsheet-model ("SPS's water model") to more closely evaluate Tolk's long-term water supply under five operating scenarios[87] and identify a water depletion window in which the Company could no longer economically meet its generation cooling needs.[88] SPS then input the parameters from the water model into the Strategist model ("Tolk Strategist analysis") to calculate present value revenue requirement of each scenario.

Q Do you have any concerns with the way SPS incorporated its water depletion assumptions into the economic analysis?

A Yes. SPS asserts that seasonal operation of the plant offers the lowest-cost option for ratepayers. However, SPS's Tolk Strategist analysis contains several flaws and shortcomings—specifically that it: (1) does not properly account for the risk that the amount of economically recoverable water may fall faster than currently contemplated; (2) does not consider the revenue that could be gained by selling the remaining water in place of using it to support plant operations; (3) does not

[86] Direct Testimony of M. Lytal at 69.

[87] Direct testimony of M. Lytal at 69-70; SPS Response to Sierra Club 1-25(CD) attachment Tolk_x water supply model_scenario_2 (*see* Exhibit DG-2); Direct Testimony of M. Lytal at Attachment ML-RR-3(CD).

[88] Direct Testimony of M. Lytal at 69-70.

directly consider the impact that accelerated water shortages could have on the plants' peak availability; and (4) is limited to five scenarios that each assume continued operation and do not contemplate retirement earlier than 2025 alongside replacement with alternatives.

i. SPS's economic analysis does not properly evaluate the risk that the amount of economically recoverable water may fall faster than SPS currently contemplates

Q Please summarize this section.

A First, I discuss my concerns with the way SPS incorporated, and relied upon, the WSP groundwater modeling into the Company's economic modeling and its plan to operate Tolk seasonally given the level of uncertainty in the WSP groundwater modeling. Second, I outline the implications of SPS's failure to incorporate the risks that agricultural and municipal pumping will deplete the aquifer faster than anticipated into its SPS's spreadsheet water model. Finally, I conclude that SPS has not presented adequate evidence to demonstrate that the aquifer can economically supply the water needed to support operations through 2032.

Q Do you have concerns with the Company's use of the WSP groundwater modeling to develop its plan to operate Tolk seasonally?

A Yes, SPS asserts that the WSP groundwater modeling "confirms that reduced operations can extend the useful lives of the Tolk units until 2030–2032 relative to typical operations."[89] However, the results presented by WSP actually do not

[89] Direct Testimony of M. Lytal at 72; Exhibit DG-12, *2018 Groundwater Modeling Results*, Xcel Energy (Nov. 2018).

fully support this statement. While the report finds that the difference between the available water supply and demand was likely to be significantly lower under an optimized demand scenario (relative to a tradition demand scenario), the report clearly states:

> "SPS will likely have challenges meeting the average annual groundwater demands throughout both scenarios, with these challenges accelerating in the year 2024. Meeting peak demands in the summer will also likely be a challenge for the wellfields starting in 2019."[90]

Moreover, WSP acknowledges that its model may have underestimated depletion rates, most notably because of the uncertainty about groundwater pumping rates from irrigators located close to the SPS Water Rights Area ("XWRA") boundary.[91]

Q What are the implications of WSP's findings that meeting peak water demands will be challenging starting in 2019, and accelerating starting in 2024?

A WSP's findings indicate that it will be difficult for SPS to ensure access to sufficient water at peak times through 2032, even assuming a baseline-level of additional wells. This means that water could be depleted more quickly than modeled in SPS's water model, and the Company would therefore need to spend more money than currently included in the Tolk Strategist analysis to maintain

[90] Direct Testimony of M. Lytal at Attachment 2018_Xcel_Groundwater_Model_Update_final_reduced, page 3; Exhibit DG-12, *2018 Groundwater Modeling Results*, Xcel Energy (Nov. 2018).
[91] *Id.*

access to sufficient water. Any wells required beyond that baseline will make Tolk more uneconomic. Therefore, SPS's Strategist economic analysis should have included robust evaluation of sensitives for deviations from (1) the water depletion windows calculated in SPS's water model, and thus (2) an increase in the number of wells required to supply peak water demands.

Instead, SPS's economic analysis relies on a best-case scenario input assumption around water availability, without also including any evaluation of the costs and impact on ratepayers if the water actually costs more to procure going forward. Just as prudent utilities evaluate a range of fuel and capital cost assumptions, energy prices, and load forecasts, SPS should have evaluated a high-band water depletion scenario that reflects the very real risk that SPS's baseline assumption is overly optimistic.

Q Please explain why pumping by irrigators located close to the SPS Water Rights Area ("XWRA") is relevant to SPS's analysis.

A The amount of water available to Tolk is critically influenced not just by how much water the Company uses at the plant, but also by how much water agricultural and municipal entities in the area are using.[92] SPS witness Lytal acknowledged this in stating that "one of the most significant variables in the WSP model relates to the amount of agricultural water used in the model domain outside of the SPS wellfield, which drives overall water usage in the area."[93] This

[92] Direct Testimony of M. Lytal at 64.
[93] *Id.*

means that SPS has no control over a main factor driving depletion of its water supply.[94]

Q How large of an impact could changes in agricultural and municipal pumping have on the aquifer depletion rates?

A SPS does not quantify how large of an impact changes in area water pumping could have on depletion rates; therefore, we have no information on how the magnitude of uncertainty from external pumping compares to the magnitude of impacts from changing plant operations.[95] Without this information, the Commission cannot know whether internal operational efforts by SPS to manage aquifer depletion rates could be easily negated and overwhelmed by changes in external pumping practices.

Q How does SPS's water model take into account the uncertainty of pumping by agricultural and municipal parties in the area?

A SPS's water model uses a small range (three years) of potential depletion dates to capture some uncertainty.[96] However, the model does not directly quantify or evaluate uncertainty from agricultural and municipal pumping. SPS's water

[94] *Id.* at 72.

[95] SPS Response to Sierra Club 1-19 (*see* Exhibit DG-2). SPS states that it has not performed any analysis to evaluate or quantify the risk of less than projected economically recovery water resources preventing seasonal operation of the Tolk plant through 2032.

[96] *Id.*

modeling focuses only on how changes in operation of its own plants impact the water depletion timeline.[97]

Q Do you have any other concerns with SPS's modeling of future water availability?

A Yes. None of the groundwater modeling on which SPS relies considers the risk of future regional droughts leading to less economically recoverable water.[98] Drought can directly impact the water available to Tolk. For example, by decreasing the surface water available to municipal and agricultural parties in the area, drought can cause an increase in the rate at which they draw from the aquifer beyond the levels anticipated.

Q Has SPS adequately demonstrated that optimized seasonal operations will ensure there is sufficient water to sustain operations through 2032?

A No. While SPS has definitely demonstrated that there is not sufficient water to sustain operations through the currently approved 2042 and 2045 retirement dates, the Company's analysis does not demonstrate that there will be sufficient water to sustain operations through 2032. As discussed above, SPS will face increasing challenges meeting groundwater need as soon as 2019 and accelerating beyond 2024.[99] Despite this, SPS is still proposing to run Tolk in seasonal operations

[97] SPS Response to Sierra Club 1-25(CD) attachment Tolk_x water supply model_scenario_2 (*see* Exhibit DG-2).

[98] SPS Response to Sierra Club 1-18 (*see* Exhibit DG-2).

[99] Direct Testimony of M. Lytal at Attachment 2018_Xcel_Groundwater_Model_Update_final_reduced, page 3.

mode for an additional 13 years beyond the 2019 date of increasing challenges, and eight years beyond the 2024 date of the onset of accelerating problems.

Q If the evidence does not definitively support the feasibility or economic soundness of operation through 2032, why is SPS proposing this date?

A It is unclear why SPS is requesting approval for a 2032 retirement date for ratemaking reasons while simultaneously admitting its analysis shows that an earlier retirement date is likely.[100] Specifically, Witness Weeks includes the following in testimony:

> "Q: If SPS's analysis shows that the retirement date for Tolk could be earlier than 2032, why does SPS propose a 2032 retirement date for ratemaking purposes?
>
> A: SPS is proposing a 2032 retirement date to be conservative for ratemaking purpose. SPS first requested the retirement date EOY 2032 in Docket 47527."[101]

The lack of clarity provided by the Company here on why the 2032 date was selected indicates that it is was likely arbitrarily selected rather than supported by analysis or actual evidence.

[100] Direct Testimony of B. Weeks at 35.

[101] Direct Testimony of B. Weeks at 34-35.

ii. SPS's economic analysis does not consider alternative uses for the water other than plant operations at Tolk

Q Has SPS considered selling its water rights instead of using the water to operate Tolk?

A No. SPS claims it has not explored any opportunities to sell the water the Company would otherwise use to operate Tolk.[102]

Q Is there evidence that there would be demand for Tolk's water supply or Xcel's water rights?

A Yes. SPS discussed the possibility of buying water from the City of Lubbock. This plan was not pursued because the City realized it did not have sufficient water to supply Tolk.[103] SPS has also discussed the declining levels of water available for area agricultural and municipal parties. All of these parties facing water shortages themselves present potential buyers for the water that SPS is currently using to run Tolk.

Q What is the implication of omitting this potential revenue stream from economic or retirement analysis of Tolk?

A The value of selling the water or water rights represents a real value stream that SPS could realize under alternative resource scenarios. Omitting potential revenue streams from the sale of Tolk's water results in an undervaluing of alternative resource options relative to continued operations of Tolk. SPS's economic

[102] SPS Response to Sierra Club 1-20 (*see* Exhibit DG-2).

[103] Direct Testimony of W. Grant at 78.

analysis does not properly reflect how the water shortage will impact peak capacity availability

Q How does uncertainty about future water availability discussed above impact the economics of operations at Tolk?

A SPS cited the value of Tolk's capacity as a reason to maintain the unit as a seasonal resource.[104] However, WSP's findings clearly indicate that SPS will have trouble maintaining access to water sufficient to support peak summer operations beyond 2019.[105] Based on this uncertainty, SPS cannot rely on Tolk's full capacity as a firm resource during summer peaks. Therefore, modeling Tolk at its full capacity results in an overstatement of the summer capacity value that Tolk actually provides to the system and overstates the value of keeping Tolk operating as a generator.

iii. SPS's economic analysis is limited in scope and fails to consider retirement in advance of 2025

Q Please summarize this section.

A In this section I review the limitations of the Strategist modeling that SPS performed using the water depletion findings from the Company's water model. I discuss how SPS constrained its analysis to only five scenarios and did not consider retirement in advance of 2025 in any of its scenarios. Then, I discuss why the Tolk Strategist analysis does not actually provide adequate information

[104] Direct Testimony of M. Lytal at 69.

[105] *Id.* at Attachment 2018_Xcel_Groundwater_Model_Update_final_reduced, page 3.

on whether continued operation of Tolk in seasonal mode through 2032 is the least-cost option for ratepayers.

Q Please describe SPS's Strategist analysis and how it connects with the WSP groundwater modeling, and SPS's water model.

A SPS used the Company's water model to develop an estimate of when aquifer depletion would occur based on five different scenarios of plant operation. SPS then modeled these five scenarios (Table 10) of plant operation in the Strategist model,[106] along with the costs required for each, to determine the total cost of each scenario.[107] SPS presented the net present value of revenue requirements ("NPVRR") of each scenario, and the cost difference for each scenario relative to the baseline of sustaining current operations through 2025.

[106] "Strategist is a resource planning model specifically designed to determine the least-cost resource mix for a utility system from a prescribed set of resource technologies under given sets of constraints and assumptions." Direct Testimony of B. Weeks at 16.

[107] SPS modeled the following costs for each scenario: (1) ongoing capital expenditures; (2) ongoing capital expenditures associated with additional water wells; (3) the cost associated with synchronous condensers; (4) fixed O&M; (5) and costs associated with TUCO fuel handing. Direct Testimony of M. Lytal at 73.

Table 10: Strategist scenarios modeled by SPS

Scenario	Description
Scenario 1	Full economic dispatch until the water runs out
Scenarios 2-4	Variations of economic dispatch in peak season and operation of one or both units in either Synchronous Condenser mode or at minimum load in off-peak seasons
Scenario 5	Full economic dispatch of one unit with retirement of the other unit and installation of synchronous condenser

Source: Direct Testimony of B. Weeks at 31-32.

Q Do the scenarios modeled capture an adequate range of operational scenarios?

A No. All of SPS's scenarios assume that both units stay online as generators through at least 2025. This means there is no analysis of partial or full retirement of the generation assets in advance of 2025 and replacement with alternatives. In other words, SPS's strategist analysis does not answer the question, "What is the least-cost option for ratepayers going forward to provide the energy, capacity and voltage support services that the system needs, and would otherwise get from Tolk?" Instead, SPS's Strategist analysis answers the question, "Assuming the Tolk units stay online as generators through at least 2025, which combination of seasonal operation, generator retirement, and operation in synchronous condenser mode, from among the five options we have outlined, is the lowest cost?" This is not a replacement or a retirement analysis: rather, this is a comparison of the costs of five specific scenarios that all assume full operation through 2025.

Q Is it reasonable for SPS to narrow down a unit replacement or economic analysis to that set of potential scenarios?

A While it can be reasonable for a utility to conduct economic analysis based on comparing only specific scenarios, those scenarios need to be inclusive of the full range of reasonable results, spanning near-term retirement, through long-term

continued operation. In this case, the given scenarios were all biased towards continue operations of Tolk, and therefore the scenarios did not encompass a full range of outcomes. Therefore, the results are unsuitable for determining whether seasonal operation through 2032 is the least-cost plan for ratepayers.

Q What are the implications for ratepayers of SPS relying on outdated retirement analysis and incomplete Strategist modeling of seasonal operations?

A Ratepayers are being asked to pay for a resource plan that SPS has not demonstrated is the lowest-cost option to provide the energy, capacity, and voltage support services. Instead, SPS has calculated the net present value of revenue requirements for a few specific scenarios based on a set of incomplete model inputs. This means that SPS is saddling ratepayers with the cost of operating Tolk without adequately evaluating whether retiring the plant prior to 2025, and replacing it with lower cost resources, would be less costly to ratepayers.

iv. SPS should incorporate the risks and opportunities relating to water and water shortage, among other modifications, into an updated retirement analysis

Q Please summarize how SPS should incorporate all of the factors outlined above into an updated economic analysis of Tolk.

A SPS should evaluate, and incorporate into an updated unit replacement and retirement modeling of Tolk, the following items (in addition to other modifications described in other sections of my testimony, including additional environmental risks and costs): (1) the value of selling the water (or even water rights) that Tolk would otherwise rely on for cooling; (2) capacity de-ratings for

Tolk based on the real and likely risk that water availability may not be able to support future peak operations; and (3) operation of Tolk in synchronous condenser mode year-round starting when the conversion is complete.

Q How should SPS be incorporating the opportunity cost to sell water?

A SPS should add the revenue that the Company would earn from selling Tolk's water, or alternatively the value to the Company of using the water at Plant X as a value stream in its economic modeling. SPS actually does currently include an opportunity-cost adder to alter Tolk's offer price to reduce plant dispatch and reduce water consumption when making dispatch decisions.[108] However, this has not been incorporated into its planning analysis. SPS has already committed, as part of its settlement of the parallel New Mexico rate case, to consider the value of reselling its water rights in the updated analysis that it performs as part of the Company's 2021 New Mexico IRP.[109]

Q How should the uncertainty around future water availability to support peak operations be integrated into SPS's modeling?

A Tolk's firm capacity should be de-rated over the years to reflect the constraints water availability will place on Tolk's ability to meet peak summer demand. In the Strategist model, SPS models Tolk at full capacity (540 MW for Unit 1 and

[108] SPS Response to Sierra Club 3-1b (*see* Exhibit DG-2).

[109] *In the Matter of SPS's Application for: (1) Revision of its Retail Rates Under Advice Notice No. 282; (2) Authorization and Approval to Shorten the Service Life of and Abandon its Tolk Generating Station Units; and (3) Other Related Relief*, Uncontested Comprehensive Stipulation, N. M. Pub. Regulation Comm'n Case No. 19-00170-UT at 4-5 (Jan. 13, 2020).

543 MW for Unit 2) through 2032.[110] This allows SPS to credit the full capacity of Tolk towards meeting its reserve margin, and therefore avoiding new capacity. In reality, Tolk's capacity should be de-rated after 2019 to reflect the risk that the Company will not be able to economically procure sufficient water to support peak operations.

Q What alternatives should SPS be considering for supplying the year-round voltage support services currently provided by Tolk?

A SPS currently plans to get voltage support services from Tolk both when the plant is operating in generation mode and as a synchronous condenser. However, SPS does not need to operate the plant as a generator between June and September (peak season), as currently planned, to obtain voltage support. Instead, as an alternative, SPS should evaluate retiring the generation portions of Tolk as soon as it installs the synchronous condenser, and operating the plant year-round in only synchronous condenser mode. Converting the coal plant exclusively to a synchronous condenser would allow SPS to meet its voltage support needs, while extending the depreciation schedule for the Tolk assets required for synchronous condenser operation.

[110] SPS Response to Sierra Club 2-2 (*see* Exhibit DG-2).

7. SPS SHOULD PERFORM UPDATED RETIREMENT ANALYSIS FOR TOLK AND HARRINGTON THAT COMPREHENSIVELY EVALUATES ALTERNATIVES AS WELL AS ENVIRONMENTAL REGULATIONS, WITH ACCURATE UPDATED ASSUMPTIONS

Q Please summarize this section.

A In this section I first review the prior retirement analysis conducted for Tolk and Harrington and find that the most recent analysis from 2014–2015 needs to be updated based on changes in the prices of gas and renewables. These prices have dramatically shifted the electricity market. I will note that SPS was or should have been aware of these changes ahead of the filing of this rate case. Second, I summarize environmental regulations that could impact plant operations in the future, yet that SPS failed to include in its modeling. I then discuss the likely impact that each would have on plant economics. Finally, I outline my recommendations for an updated retirement analysis for both Tolk and Harrington that fully considers alternative resources and properly evaluates what the system actually needs.

i. SPS's most recent retirement analysis reflects outdated assumptions and market trends

Q When did SPS last conduct retirement analysis for its coal units?

A SPS's last retirement analysis of Tolk and Harrington was completed in the 2014–2015 timeframe (this analysis was conducted using the Strategist model).[111] SPS actually concluded from this analysis that shutting down Tolk would not be

[111] SPS Response to Sierra Club 1-6 (*see* Exhibit DG-2).

expensive due to the presence of the production tax credits and investment tax credits for renewables, and due to lower gas and oil prices. Additionally, the analysis concluded that SPS should acquire additional wind resources and seek additional solar resources in late 2016.[112] It is unclear why the Company did not act on this finding. For this current rate case, SPS conducted Strategist analysis as well. However as discussed above, the analysis was constrained to five operational scenarios for the Tolk Plant and did not consider retirement for Tolk prior to 2025.

Q Why should SPS do a full updated unit replacement analysis for Tolk and Harrington?

A There have been large shifts in electricity markets since 2014–2015. These changes include the persistence of low natural gas prices, declining costs of renewables and storage, and minimal growth in electricity demand. The status of environmental regulations that could require large capital expenditures to comply has also changed. Additionally, the new operational constraints at Tolk significantly change the economics of operating the plant. Finally, neither Tolk nor Harrington are locked into a long-term coal contract that would pose a challenge to early retirement; [113] therefore there are no significant cost barriers to retirement.

[112] SPS Response to Sierra Club 1-6(a); Exhibit SPS-Sierra Club 1-6(a) at 33 (*see* Exhibit DG-2).
[113] Direct Testimony of H. C. Romer on Behalf of SPS at 22.

Q What impacts have electricity market trends had on the operations of coal-fired plants nationwide?

A In recent years, the trends around lower-cost gas and renewables, combined with the higher cost of environmental compliance for higher-polluting coal units, have driven the retirement of many coal units. The EIA recently reported that more than 65,000 MW of U.S. coal capacity retired between 2007 and 2018.[114] Furthermore, 2018 saw nearly 13,000 MW of U.S. coal capacity retired.[115] As an alternative to shutting down, some coal-fired plants, such as the Dolet Hill plant in Louisiana, have switched to seasonal operation, shutting down in off-peak seasons when demand is low and turning back on for just the peak seasons.[116] This decreases the environmental impact of running the plants while allowing the utility to retain the peak capacity.

[114] Exhibit DG-13, EIA, "U.S. coal consumption in 2018 expected to be the lowest in 39 years." (Dec. 28, 2018), *available at*: https://www.eia.gov/todayinenergy/detail.php?id=37817.

[115] Exhibit DG-14, EIA, "More than 60% of electric generating capacity installed in 2018 was fueled by natural gas." (Mar. 11, 2019), *available at*: https://www.eia.gov/todayinenergy/detail.php?id=38632; Exhibit DG-15, Nelson, William and Sophia Lu, Half of U.S. Coal Fleet on Shaky Economic Footing. Bloomberg New Energy Finance (Mar. 26, 2018).

[116] Exhibit DG-16, Gheorghiu, Iulia. Cleco, "SWEPCO shift coal plant use, target 2.8 GW renewables in latest resource plans." Utility Dive (Sept. 6, 2019), *available at*: https://www.utilitydive.com/news/cleco-swepco-shift-coal-plant-use-target-28-gw-renewables-in-latest-reso/562213/.

ii. SPS needs to include the costs and risks of all likely environmental regulations in its updated retirement analysis

Q How should SPS include the future costs and risks of environmental regulations?

A SPS should be modeling the projected impact of future environmental regulations that are likely to impact either plants. Specifically, SPS should include sensitivities in an updated unit replacement and retirement analysis on the risks of incurring new expenses for environmental compliance. The cost to comply with several of the regulations is considerable, meaning the economics would likely not support installation of the environmental controls and continued operation of the units. As such, SPS should evaluate resource portfolio options that can economically replace each plant over the range of possible years, reflecting the uncertainty in the timing of when the regulations discussed below could be implemented.

Table 11 lists proposed environmental rules and their likely associated cost that SPS should add, at a minimum, to its existing modeling.

Table 11: Proposed and final environmental rules that could impact Tolk and Harrington

Rule	Details	Cost
Regional Haze	Tolk identified as a "reasonable progress" source contributing to regional haze, and required to install dry scrubbers by Feb 2021; Xcel challenged that rule, and the Fifth Circuit remanded to EPA for review in 2017; there has been no action since, but the plant would be subject to review in 2021 plan.	Tolk: $400–$600 million,[117] plus $24 million annual O&M
Best Available Retrofit Technology (BART)	Harrington identified as "best available control technology" source; no final action taken yet.	Harrington: $400–500 million, plus $21 million annual O&M
Affordable Clean Energy Rule	Emissions guidelines, finalized July 2019.	TBD

Source: SPS response to Sierra Club 1-8 (see Exhibit DG-2).

Q Do any SPS company witnesses acknowledge the potential impact of future environmental compliance costs on plant economics?

A Yes, on Tolk specifically. SPS witness Hudson acknowledged the potential impact on Tolk from environmental compliance costs, stating: "It should be noted that future environmental regulations may even further reduce the life span of the [Tolk] plant."[118] Additionally, the risk of future additional environmental regulations was also cited as one of the reasons SPS decided not to pursue the hybrid cooling towers at Tolk.[119]

[117] Includes additional costs for water acquisition that would need to be made to operate the dry scrubbers appropriately. SPS Response to Sierra Club 1-8 (*see* Exhibit DG-2).

[118] Direct Testimony of D. Hudson on Behalf of SPS at 27.

[119] Direct Testimony of W. Grant. at 78-79.

Q Why has SPS not included the cost of those proposed or other likely future environmental regulations in its most recent Tolk Strategist modeling?

A The Company defended its position not to include these potential costs in a discovery response by stating that "SPS does not evaluate the effect of 'possible environmental regulations' (*i.e.*, neither the subject nor a proposed or final rulemaking) because they are speculative and may never be adopted, or they may be adopted in some different form than the proposal."[120]

This classification of these costs as speculative is inconsistent with a statement provided by Company witness Hudson, who acknowledged that current studies show that converting Harrington to natural gas by 2025 is the most economical solution given the expense of installing sulfur dioxide ("SO_2") scrubbers on the plant to comply with SO_2 regulations.[121] Additionally, several Company witnesses openly acknowledged the likelihood of future additional environmental compliance costs.[122]

Q What regulations should SPS include in its retirement analysis for Tolk?

A At Tolk, SPS should be modeling the cost to ratepayers of keeping Tolk if EPA moves forward on the "reasonable progress" requirements of the federal Regional

[120] SPS Response to Sierra Club 1-8 (*see* Exhibit DG-2).

[121] "SPS's current economic studies show that converting Harrington Station to natural gas by 2025 is the most economical solution given the very high capital cost to install SO_2 scrubbers on each unit (about $170 million each). Given the age of the units (over 40 years), other potential environmental constraints like carbon reduction, and the anticipated economical costs of continuing to operate Harrington Station as a coal plant, we expect that to meet customer reliability and affordability, it makes the most sense to switch Harrington Station to natural gas by 2025." Rebuttal Testimony of D. Hudson, N.M. Public Regulation Comm'n Case No. 19-00170-UT at 40 (Dec. 20, 2019).

[122] *See*, *e.g.*, Direct Testimony of W. Grant. at 78-79.

Haze Rule, which could require the installation of ion dry scrubbers at a cost of $400–$600 million with annual O&M of $24 million.[123] It is worth noting that, regardless of the status of EPA's current regional haze rulemaking, Tolk would be subject to review and further control analyses in 2021, during the second planning period under the Regional Haze Rule.[124]

Q What regulations should SPS include in its retirement analysis for Harrington?

A At Harrington, SPS should be modeling the costs of installing additional SO_2 controls, which SPS indicated may be required to comply with the National Ambient Air Quality Standards (NAAQS).[125] EPA's ruling on a final designation is expected by December of 2020 (once monitoring is finalized).[126] In 2017, EPA also proposed to require the installation of scrubbers at two of the Harrington units under the "best available retrofit technology" provisions of the regional haze rule.[127] Harrington's environmental compliance risk under the regional haze rule is still unresolved. As with Tolk, Harrington would also be subject to review and further control analyses in 2021, during the second planning period under the Regional Haze Rule.[128] The Company admitted that it has not evaluated the

[123] Direct Testimony of W. Grant at 78-79.

[124] *See* 40 C.F.R. §§ 51.308(d), (f).

[125] SPS Response to Sierra Club 1-8 (*see* Exhibit DG-2).

[126] *Id.*

[127] Promulgation of Air Quality Implementation Plans; State of Texas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan, 82 Fed. Reg. 912, 949 (Jan. 4, 2017).

[128] *See* 40 C.F.R. §§ 51.308(d), (f).

impacts that these potential investments will have on the economic operation of the Harrington units.[129]

Q How does SPS's omission of potential environmental regulations impact the Strategist modeling results?

A Omission of these costs leads to understating the ongoing costs to operate the coal plant, and therefore makes the coal plants appear more economic than they are likely to be in reality. This also prevents SPS from adequately evaluating and planning for alternatives to provide the energy, capacity, and other services that the Company would need to replace either unit. If the EPA moves on the Regional Haze Rule or NAAQS SO_2 compliance, and Tolk or Harrington are required to install new environmental controls, the costs of compliance could easily exceed the economic value to ratepayers of continuing to operate the plants. These risks are real and should be factored into the utility's forward-looking decision-making.

iii. SPS should perform this updated retirement analysis and present it in the Company's next rate case

Q How should SPS be evaluating the energy, capacity, and other services that it actually needs in a retirement analysis?

A In its future retirement analysis, SPS should focus on evaluating what the system actually needs in terms of energy, capacity, and other grid services, once one or both of the plants (or certain of their units) are retired. This is different than how utilities, including SPS, have traditionally approached retirement and replacement

[129] SPS Response to Sierra Club 1-8 (*see* Exhibit DG-2).

analysis by focusing on a replacement resource, or combination of resources, that provides the services that the retiring resource provides. This is critically inefficient because it presumes that the retiring unit was supplying exactly what the system needed, and this is almost never true. While the system needs may be aligned with or similar to the characteristics of the retiring unit, this approach biases resource planning in favor of resources that look like the resource that was retired, and that means fossil generators instead of alternative portfolios that include renewables, battery storage, and demand-side management.

Q What do we know about SPS's current capacity need?

SPS's demand forecasts dropped each year between 2014 and 2018, before increasing again in 2019 (

A Figure 7 and Table 12). This means that when SPS completed its retirement analysis back in 2015, the Company assumed a significantly higher level of demand than we know has actually materialized. In a high demand future, Tolk and Harrington would be assigned a high capacity value, and therefore the model would be less likely to retire the resources. With the Company's most recent Tolk Strategist analysis, SPS relied on its 2019 demand forecast, which projected a much higher level of demand than just a year prior in the Company's 2018 New Mexico IRP. This projected upturn in demand is driven by the Eddy County and Lea County Permian Basin oil and natural gas customer segments,[130] an industry where short-term growth often does not translate into sustained long-term demand. Once again, to fill perceived need of this new industry, the Strategist model would be likely to keep Tolk online as a generator, based on the avoided cost of building new capacity.

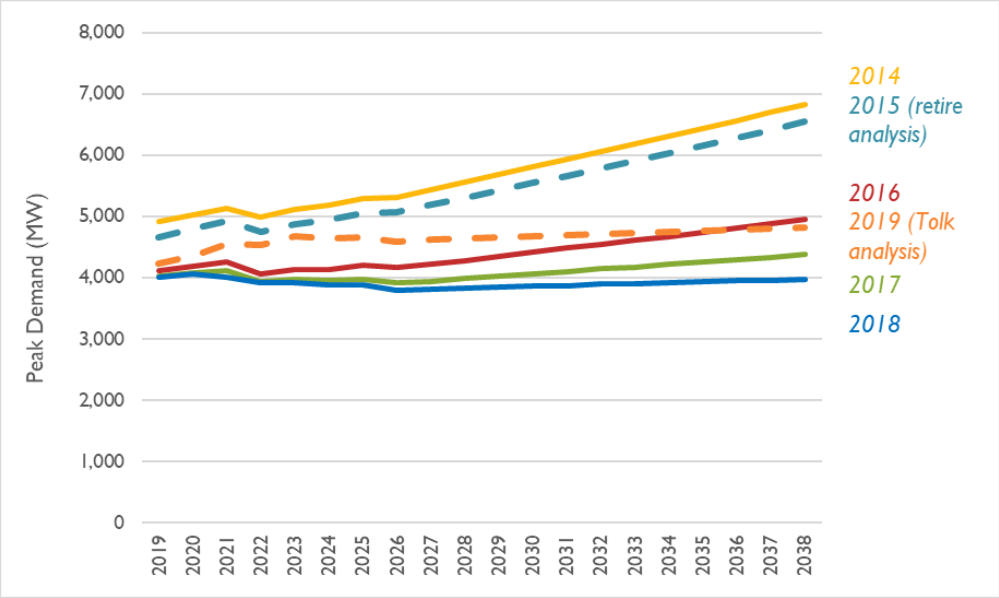
[130] Direct Testimony of D. Hudson at 28-29.

Table 12: Peak demand growth rates from SPS's load forecasts (2019–2038) (whole Company)

Forecast	Compound Average Growth Rate (CAGR)
2019 Tolk Strategist analysis	0.76%
2018 New Mexico IRP	0.0%
2014/2015 Strategist retirement analysis	1.75%

Source: SPS Response to Sierra Club 1-12; Workpaper SO - _SPS_SCENARIO2_REDUXOPS_2031.xlsx"; SPS Response to Sierra Club 1-6, Attachment SO – 05_RET EOY 21 23 (see Exhibit DG-2).

Figure 7: SPS's peak demand forecasts (2019–2038)



Source: SPS Response to Sierra Club 1-12; Workpaper SO - _SPS_SCENARIO2_REDUXOPS_2031.xlsx"; SPS Response to Sierra Club 1-6, Attachment SO – 05_RET EOY 21 23 (see Exhibit DG-2).

Q What do we know about what SPS likely needs for energy, capacity, and voltage support services if Tolk retires?

A If Tolk retires and SPS has a capacity shortfall, the need should roughly align with the summer peak capacity that Tolk was going to provide operating in seasonal mode. This makes solar particularly well suited as a replacement option

due to the alignment between the timing of system peak and solar generation in the region during summer months. If Tolk's retirement creates an energy need that cannot be met by solar, existing resources on the grid could likely ramp up to provide the energy. SPS should not need any additional voltage support services when Tolk retires the plant's generation assets, assuming the proposed synchronous condenser is installed.

Q What alternatives should SPS be considering in its retirement analysis for Harrington?

A SPS should evaluate alternative resource options, including wind, solar, and battery storage, in addition to market purchases to replace Harrington. Additionally, the Company should be considering alternative operational options, such as seasonal operation for some or all the units. Seasonal operations would allow the Company to retain the capacity from the units but decrease the plants operational costs by generating electricity only during summer peak months when LMPs are highest. This would also decrease the environmental impact of the units by decreasing the amount of coal burned, which could have implications for compliance with the environmental regulations discussed above. This approach to switch to seasonal operation has been adopted by several plants, including Dolet Hills.[131]

[131] Exhibit DG-17, Daniel, Joseph. "Seasonal Shutdowns: How Coal Plants that Operate Less Can Save Customers Money." Union of Concerned Scientists (Dec. 20, 2018), *available at*: https://blog.ucsusa.org/joseph-daniel/seasonal-shutdowns-how-coal-plants-that-operate-less-can-save-customers-money.

Q What do we know about the cost competitiveness of the renewables mentioned above in the region?

A Other utilities in the region are actively procuring renewables. Public Service Company of New Mexico ("PNM") recently issued an all-source request for proposals ("RFP") in which the Company will seek to assess and integrate all bids, including packaged renewable energy, storage, demand-side resources, and distributed energy solutions.

Similarly, another Xcel subsidiary, Xcel Energy Colorado, recently conducted an all-source RFP and received over 400 bids, most of which were for renewable resources, with the median bid for stand-alone wind energy resources at $18.10/MWh. Adding battery storage to wind energy resulted in median bids of $21/MWh. Moreover, Xcel Energy Colorado received 152 bids for solar projects comprising more than 13 GW of capacity, with the median bid at $29.50/MWh. Coupling solar with battery storage resulted in bids for $36/MWh. SPS should conduct a similar RFP process, and incorporate those cost assumptions into a revised retirement and replacement analysis.[132]

Q Please summarize your recommendations to the Commission with regards to updated retirement analysis for both Tolk and Harrington.

A The Commission should require that SPS conduct an updated and more comprehensive retirement analysis for both Tolk and Harrington, and present that analysis as part of the Company's next rate case. This analysis should include

[132] Exhibit DG-18, *In the Matter of the Application of Pub. Serv. Co. of Colo. for Approval of its 2016 Electric Resource Plan*, Xcel Energy, 2016 Electric Resource Plan, 2017 All Source Solicitation 30-Day Report (Public Version), Colo. P.U.C. Proceeding No. 16A-0396E (Dec. 28, 2017).

updated peak demand and load forecasts, alternative resource costs based on an RFP process similar to the ones outlined above, and alternative operational options, specifically seasonal operation for Harrington. Further, it should incorporate sensitivities around the cost of all likely future additional environmental regulations, as discussed above. Additionally, the retirement analysis for Tolk should include scenarios that incorporate capacity de-rating based on future water availability constraints, and the potential revenue from selling the water to other parties.

Q Does this conclude your testimony?

A Yes.