DOCKET NO. 54634

APPLICATION OF SOUTHWESTERN PUBLIC SERVICE COMPANY FOR AUTHORITY TO CHANGE RATES	§ § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

PUBLIC

Direct Testimony

of

Devi Glick

On Behalf of

Sierra Club

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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 Principal at Synapse Energy Economics, Inc. ("Synapse"). 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 power plant economics, electric system dispatch, integrated resource planning, environmental compliance technologies and strategies, and valuation of distributed energy resources. I have submitted expert testimony before state utility regulators in more than a dozen states.

In the course of my work, I develop in-house models and perform analysis using industry-standard electricity power system models. I am proficient in the use of spreadsheet analysis tools, as well as optimization and electric dispatch models. I have directly run EnCompass and PLEXOS energy modeling software's and have reviewed inputs and outputs for several other models.

Before 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 10 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 Yes. I submitted testimony on behalf of Sierra Club in prior dockets relating to Southwestern Public Service Company ("SPS"), specifically Docket No. 52485 and Docket No. 49831. I have also submitted testimony on behalf of Sierra Club in several dockets relating to Entergy Texas, specifically Docket No. 53719 and Docket No. 5248, and in several dockets relating to the Southwest Electric Power Company, specifically Docket No. 51415 and Docket No. 50997.

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

A In this proceeding, I evaluate SPS's request to move up the retirement date of the Tolk Generating Station ("Tolk") from 2032 to 2028, and its associated plan to modify its Tolk Optimization Plan to increase operations at the plant year-round instead of continuing to operate in conservation mode, as approved by the Commission in Cases Nos. 19-00170-UT, and 20-00238-UT.[1] I review the risks to SPS ratepayers of the Company continuing to operate and rely on an aging coal resource through 2028, and its future plans to pivot to a heavy reliance on gas resources beyond 2028. I also review whether SPS has acted reasonably in evaluating the economics of Tolk in prior dockets, and in taking action to procure resources to replace Tolk. Finally, I outline alternative financing and cost recovery mechanisms that SPS can use to minimize the cost impacts to ratepayers from the early retirement of Tolk.

Q How is your testimony structured?

A In Section 2, I summarize my findings and recommendations for the Commission.

In Section 3, I describe the Tolk Generation Station and summarize SPS's proposal to move the retirement date up for Tolk from 2032 to 2028 and to modify the current Tolk Optimization Plan to operate the plant year-round instead of conserving cooling water by reducing annual generation levels at the plant. I

[1] As SPS Witness Elsey indicates, the "Tolk Optimization Plan" means "reducing operations to conserve water and preserve the capacity of the Tolk units." Direct Testimony of Ben R. Elsey at 4. This is synonymous with the "conservation mode" operations that the Commission approved in Case Nos. 19-00170-UT, and 20-00238-UT. *See, e.g.,* Order Adopting Certificate of Stipulation with Modification at 4, Case No. 20-00238-UT, (Feb. 2, 2022). Accordingly, in this testimony, I refer to current conservation mode operations as the "Tolk Optimization Plan." I refer to SPS's proposed Tolk operational plan, in which the Company plans to increase generation at the units as the "Modified Tolk Optimization Plan."

also review SPS's current resource mix, near-term resource planning actions and needs, and the Company's carbon dioxide ("CO_2") reduction goals and trajectories.

In Section 4, I summarize my evaluation of the economic performance of Tolk based on the Company's own data and discuss current cost and market trends for renewable alternatives in the region. I review the most recent analysis the Company completed to justify both (1) the accelerated retirement date of Tolk, and (2) modifying operations to increase generation year-round at Tolk through 2028. I summarize my concerns with the current analysis, as well as prior Tolk analyses completed by SPS. I discuss the risks to SPS ratepayers of SPS's continued reliance on coal generating assets, including the risk of increased environmental compliance costs posed by the recently updated Good Neighbor Rule. I discuss my recommendations for SPS to reduce operations at the plant and operate Tolk only when it is economic to do so, taking into account the full dispatch cost inclusive of the cost of nitrogen oxide ("NOx") emissions credits. I also outline the risks associated with SPS's plans to switch to reliance on mostly gas resources going forward. Finally, I outline alternative financing and cost recovery mechanisms that SPS can use to minimize the cost impacts to ratepayers from the early retirement of Tolk.

In Section 5, I explain the need for SPS to be more proactive and flexible in procuring replacement resources to accelerate its transition to clean energy resources, rather than waiting until a resource has become uneconomic and it has an urgent capacity need.

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's witnesses. I also rely on public information from other PRC proceedings and other publicly available documents.

2. <u>FINDINGS AND RECOMMENDATIONS</u>

Q Please summarize your findings.

A My primary findings are:

1. Based on the Company's own data and analysis, I find that the cost to operate and maintain Tolk beyond 2028, and the risks that continued operations of Tolk pose to SPS ratepayer, substantially exceed the cost of alternative clean energy resources.

2. SPS can avoid substantial capital expenditures and operations and maintenance ("O&M") costs by retiring Tolk no later than 2028 instead of continuing to invest in it.

3. The analysis SPS used to support the accelerated depreciation date for Tolk shows that it is likely lower cost to retire the plant and replace it with clean energy alternatives as soon as possible and even prior to the currently planned retirement date of 2028.

4. SPS failed to evaluate the economics of continuing to operate Tolk with reduced operations, that is under its current Tolk Optimization Plan and with a 2028 retirement date or by modeling economic dispatch of Tolk but with the full NOx emission costs reflected in the units' market offer price.

By constraining its analysis to scenarios that utilized all remaining water at Tolk, SPS is leaving the Commission without information necessary to determine whether one of the two scenarios it evaluated is actually the least-cost scenario.

5. SPS's modeling shows that the Company's proposal to accelerate the retirement of Tolk is driven mainly by the Company's projections of high near-term gas prices and only minimally by lower renewables costs assumptions resulting from the *Inflation Reduction Act* ("IRA"). Specifically, the Company's modeling shows a near-term increase in coal generation and decrease in gas generation (relative to what it planned based on the prior Tolk analysis) followed by a significant and concerning build-out of new gas resources and minimal renewable additions to replace Tolk when it retires.

6. SPS can reduce the risks to ratepayers of running out of water, preserve optionality in the event that replacement resource procurement is delayed, reduce emissions, and likely even reduce costs by reducing operations at Tolk and operating the plant economically, based on a dispatch cost inclusive of the full cost of future NOx emission credits, between now and when Tolk retires.

7. SPS can reduce the cost to ratepayers associated with early retirement of Tolk by utilizing alternative rate mechanisms.

Q Please summarize your recommendations.

A Based on my findings, I offer the following recommendations:

1. SPS should immediately re-issue its current request for proposal ("RFP"), with a 2028 commissioning date, to solicit bids for replacement resources for Tolk.

2. SPS should minimize how much it operates Tolk in general to reduce emissions, to conserve water, avoid environmental compliance costs and to preserve optionality in the event that water runs out more quickly than currently anticipated—or SPS faces delays in bringing replacement resources online in time. When SPS does dispatch Tolk, it should do so economically based on a dispatch cost inclusive of the full cost of NOx emission credits.

3. SPS should act swiftly to secure and bring online replacement clean energy resources, including solar PV, wind, battery storage, and demand-side measures, as soon as they are available and not wait for 2028.

4. SPS should minimize spending at Tolk between now and when it retires to minimize the undepreciated plant balance for ratepayers.

5. SPS should evaluate alternative financing and cost recovery mechanisms for reducing the cost impact of retiring Tolk before it is fully depreciated. Such mechanisms include securitization and staggering of the retirement date from the depreciation date.

3. <u>SPS IS PROPOSING TO MOVE UP THE RETIREMENT DATE OF TOLK FROM 2032 TO 2028 AND TO MODIFY ITS TOLK OPTIMIZATION PLAN TO INCREASE OPERATIONS YEAR-ROUND.</u>

Q Please provide an overview of the Tolk coal-fired power plant.

A The Tolk Generating Station consists of a two-unit coal-fired power plant located in Sudan, Texas. SPS operates and owns both units. Unit 1 is 531 megawatts ("MW") and went into service 1982. Unit 2 is 538 MW and went into service in 1985.[2] Both units are currently scheduled to retire in 2032.

Q What is SPS requesting in this docket related to Tolk?

A SPS is seeking to move up the Tolk depreciation date from 2032 to 2028. Along with this change in retirement date, SPS is also planning to modify its Tolk Optimization Plan to switch from operating Tolk in conservation mode, where it is conserving the limited cooling water available, to maximizing operations year-round at Tolk.

Q What test-year costs for the Tolk plant is SPS requesting to include in rates?

A As shown in Table 1 below, SPS is requesting to place approximately $7.36 million in capital expenditures[3] into its rate base, and just under $15 million in O&M costs[4] into rates. These costs are for SPS's Updated Test Year period, January 1, 2022 through December 31, 2022.

[2] SPS 2021 Integrated Resource Plan, Pg. 9.

[3] SPS Response to Sierra Club Request 3-2.

[4] SPS Response to Sierra Club Request 1-3(f), Exhibit SPS-SC 1-3(f)(SUPP2).

Table 1.Test-year sustaining capital expenditures and operations & maintenance costs at Tolk

($Millions)	**O&M**	**Capital expenditures**
Tolk	$14.39	$7.36

Source: SPS Response to SC 1-3, Exhibit SPS-SC 1-3(f)(SUPP2); SPS Response to SC 3-2.

Q What is the undepreciated balance at the Tolk Plant?

A The plant balance for Tolk (Texas retail share) was $267 million at the end of 2022, including approximately $70 million for the synchronous condensers.[5] The Company's current rates, set during the prior rate case in 2019, reflect the retirement years of 2032 for Tolk. As part of this rate case, SPS proposes to move the depreciation date of the Plant up from 2032 to 2028. SPS wants to accelerate the depreciation of Tolk 1 and 2 as well as the Tolk Common Facilities so that the associated plant balance will be paid off by the end of 2029. SPS plans to operate the synchronous condensers beyond Tolk's retirement date[6] and is not seeking to accelerate the depreciation of the associated assets. SPS projects that an undepreciated balance of $66.36 million will remain for the synchronous condensers after the generators retire.

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[5] SPS Response to Sierra Club Request 1-5(d,e), Exhibit SPS-SC 1-5(d,e).

[6] *Id.*

Table 2. Undepreciated balance of Tolk at the start of 2023

Unit	Undepreciated book value	
	Year End 2022	Year End 2029
Tolk Common Facilities	($4,002,172)	-
Tolk 1	$87,566,460	-
Tolk 2	$100,437,115	-
Tolk Common Synchronous Condensers	$13,095,399	$9,416,329
Tolk 1 Synchronous Condensers	$32,279,950	$24,975,281
Tolk 2 Synchronous Condensers	$37,509,508	$29,218,329
Total	**$266,866,260**	**$63,609,939**

Source: SPS Response to Sierra Club Request 1-5(d,e), Exhibit SPS-SC 1-5(d,e).

Q Has SPS committed to a retirement date for Tolk?

A In the 2018 rate case, the Commission approved a revision to the Tolk units' depreciation dates that moved the retirement date for Tolk Units 1 and 2 from 2042 and 2045 respectively to 2037.[7] In Docket No. 51802, the Commission approved an uncontested stipulation further adjusting the depreciation rate for the Tolk units to correspond to 2034 retirement date.[8] In the original Tolk Analysis that SPS completed as part of its 2021 IRP, SPS modeled Tolk operating in conservation mode (or reduced operations to conserve water) through 2032. Now,

[7] Direct Testimony of Brooke Trammell, Pg. 47; Application of Southwestern Public Service Company to Change Rates, Docket No. 47527, Order at FoF No. 51 (Dec. 10, 2018).

[8] Direct Testimony of Brooke Trammell, Pg. 47; Application of Southwestern Public Service Company for Authority to Change Rates, Docket No. 51802, Unopposed Stipulation, Pg. 5 (January 26, 2022).

SPS is proposing to modify that optimization plan and maximize operations at Tolk year-round through 2028 and retire the plant at the end of 2028.[9]

Company Witness Brooke Trammell discusses SPS's request to abandon coal operations at Tolk by December 31, 2028.[10] But SPS also indicated in discovery that if the Company economically dispatches Tolk over the next few years and that results in substantially less than 4,000 GWh/year of generation, SPS would re-evaluate the 2028 retirement date.[11] This means that the Company is asking to plan around a 2028 retirement date but it is not firmly committing to such a date.

Q Does SPS have any near-term resource needs?

A Yes, effective in 2023, the Southwest Power Pool ("SPP") is increasing its minimum planning reserve margin requirement from 12 percent to 15 percent. This increase will require SPS to have 123 MW of additional accredited capacity in 2023 and 136 MW of additional capacity by 2027 over what it previously projected it would need.[12] In addition, SPP is updating its resource capacity accreditation process beginning next summer and plans to start using the effective load carrying capability methodology. This change will result in the accredited capacity for renewable and battery energy storage resources declining as the penetration of renewable resources and battery energy storage resources on the system increases. SPP is also planning to change to a performance-based

[9] Direct Testimony of Ben Elsey, Pg. 8.

[10] Direct Testimony of Brooke Trammell, Pg. 46.

[11] SPS Response to Sierra Club Request 1-28.

[12] Direct Testimony of Ben Elsey, Pg. 23.

accreditation for thermal resources starting in 2023.[13] The Company claims it needs more firm capacity resources and demand-side peak-management solutions to address the peak load increase and the changes in SPP accredited capacity requirement.[14]

In addition, SPS has seen an increase in peak demand relative to both historical levels and projected levels. Specifically, the Company's peak demand during the summer of 2022 was 4,255 MW, which is 122 MW higher than it had forecasted in its 2021 integrated resource plan ("IRP").[15] The Company projects that over the next five years, peak load will continue to grow as new customers connect to the grid. SPS has seen a reduction in its wholesale load, which has freed up some its capacity to serve retail customers, but the Company still expects to need new capacity in 2026, and potentially as early as next year (2024) if additional new load materializes.[16]

Q What near-term resource procurement efforts has SPS made?

A SPS brought online two large wind generation facilities after the last rate case. It brought online the Hale Wind Farm, a 478 MW facility, in 2019, and then the Sagamore Wind Farm, a 522 MW facility in 2020.[17] The Company has not constructed any new facilities since then.

On November 28, 2022 SPS issued an RFP to procure resources to fulfill its capacity needs through 2027. SPS plans to retire Plant X Units 1 and 2 and

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[13] *Id.,* Pgs. 28-29.

[14] *Id.*, Pgs. 23-24.

[15] *Id.*, Pg. 26.

[16] *Id.*, Pg. 26.

[17] SPS 2021 Integrated Resource Plan, Pg. 9.

Cunningham Unit 2 (all steam gas plants) in 2023. SPS is also requesting to push back the retirement date for two steam gas plants. Specifically, SPS is requesting to move the retirement dates for Nicholas Unit from 2022 to 2028 and for Nicholas Unit 2 from 2023 to 2027. SPS is requesting this change to meet SPP's increased reserve margin requirements. Bid proposals for the RFP were due February 28, 2023.[18] SPS indicated that it is still reviewing and evaluating the results and declined to provide details on the responses.[19]

4. Continuing to rely on Tolk beyond 2028 or increasing operations at the plant without regard for full unit dispatch costs, is unlikely to be the least-risk option for SPS ratepayers.

i. The operational and economic performance of Tolk Units 1 and 2 have been declining, and, based on SPS's model results I project that the units will be substantially more costly to operate in the future than resource alternatives.

Q What are the utilization levels of Tolk Units 1 and 2 in recent years?

A SPS's utilization of Tolk Units 1 and 2 has been relatively low over the past few years. As shown in Table 3 below, between 2018 and 2022, Tolk Units 1 and 2 operated at relatively low average-annual capacity factors ranging between 20 and 35 percent.[20]

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[18] SPS Response to Sierra Club Request 1-14.

[19] SPS Response to Sierra Club Request 3-1.

[20] SPS Response to Sierra Club Request 1-6, Exhibit SPS-SC 1-6(a-f).xlsx.

Table 3. Historical capacity factors 2018–2022

	2018	2019	2020	2021	2022
Tolk 1	45%	24%	20%	26%	23%
Tolk 2	37%	35%	35%	28%	32%

Source: SPS Response to Sierra Club Request 1-6, Exhibit SPS-SC 1-6(a-f).xlsx.

Q How reliable have Tolk Units 1 and 2 been in recent years?

A As shown in Table 4 and Table 5 below, each of the Tolk Units has had a relatively low availability factor and a high forced outage rate during at least two of the last five years. Tolk Unit 1's average equivalent forced outage rate[21] for the past three years (2020–2022) was 17.50 percent.

Table 4. Equivalent availability factors 2018-2022

	2018	2019	2020	2021	2022
Tolk Unit 1	81.19	93.87	62.19	89.93	60.47
Tolk Unit 2	66.77	97.24	73.57	62.15	68.08

Source: SPS Response to Sierra Club Request 1-6, Exhibit SPS-SC 1-6(a-f).xlsx.
Notes: The equivalent availability factor measures the percentage of time that a unit was available during all the hours in that period. This includes hours in which the unit was planned to be unavailable.

Table 5. Equivalent forced outage rates 2018–2022

	2018	2019	2020	2021	2022
Tolk Unit 1	1.88	5.02	21.42	16.59	14.49
Tolk Unit 2	33.55	0.50	18.14	3.34	5.57

Source: SPS Response to Sierra Club Request 1-6, Exhibit SPS-SC 1-6(a-f).xlsx.

These outages rates are much higher than the national average as reported by the North American Electric Reliability Corporation ("NERC"), which was around 7.25 percent across all grid resources for the five years between 2017 and 2021.

[21] The Equivalent Forced Outage Rate measures the percentage of time that a unit was unavailable during only the hours that it was expected to be available. This means it excludes hours when the unit was planned to be offline.

According to that same study, outage rates at coal units averaged around 10 percent nationally, worse than outage rates among all other resource types, and were steadily increasing (i.e., decreasing availability), reflecting a pattern of worsening fleet performance.[22] Although national outage rates for coal units are relatively poor, SPS's own data indicates that the Tolk units perform substantially worse in many years. These high outage rates are concerning because, as discussed later, gas and by extension market prices have become increasingly volatile. This means the short-term replacement resources that SPS must rely on in the event of outages could become very expensive for SPS's ratepayers (if replacement resources are available at all).

Q Describe Tolk's projected financial performance over the next five to ten years.

A On a forward-going basis, I find that Tolk is projected to have a levelized cost of energy ("LCOE") of around [redacted] over the next decade, as shown in Table 6 below.[23] These costs represent the total costs that SPS modeled in EnCompass; they include all fuel, O&M, and capital costs inputs in the analysis but critically do not include NO_X emission costs. LCOE's are around [redacted] lower under the Modified Tolk Optimization Plan, that is with increased year-round operations of Tolk and retirement in 2028, relative to the Current Tolk Optimization Plan, with conservation mode operations and retirement in 2032. Although the total generation values in each scenario are within 3 percent of each other, the generation occurs earlier in the Modified Tolk Optimization Plan,

[22] North American Electric Reliability Corporation, *2022 State of Reliability: An Assessment of 2021 Bulk Power System Performance*, Pgs. 37-38, (July 2022), *available at* https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2022.pdf.

[23] This is my calculation based on SPS's EnCompass model outputs.

leading to a greater net present value of energy. Furthermore, under the Modified Tolk Optimization Plan, SPS avoids fixed O&M and sustaining capital costs associated with operating and maintaining Tolk in the years 2029–2032.

Table 6. Confidential LCOE ($/MWh) of Tolk Units

Resource	Modified Tolk Optimization Plan	Current Tolk Optimization Plan
Tolk Unit 1	[redacted]	[redacted]
Tolk Unit 2	[redacted]	

Source: Synapse calculations based on SPS Response to Sierra Club Request 1-5, Exhibit SPS-SC 1-5(a)(CONF). EO - T32-T28_PL_400TRX.xlsx.

Q Explain the methodology you used to calculate the projected LCOE of the Tolk units.

A I relied on SPS data provided in discovery. From the EnCompass output files for SPS's updated 2022 Planning Load Forecast modeling,[24] I extracted the total costs associated with operating each unit per year, as well as the annual generation of each unit. I then calculated the net present value of the total costs and separately calculated the net present value of the total annual generation, using SPS's nominal weighted average cost of capital of 7.71 percent.[25] I divided the net present value of the plant's total cost by the net present value of SPS's modeled generation of each unit over the same time period. I performed this calculation for the years 2023–2028 for the Modified Tolk Optimization Plan. For the Current Tolk Optimization Plan, I performed this calculation for the years 2023–2032.

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[24] SPS Response to Sierra Club Request 1-5, Exhibit SPS-SC 1-5(a)(CONF), EO - T32-T28_PL_400TRX.xlsx.

[25] Direct Testimony of Adrian Rodriguez, Pg. 28.

Q How does the cost to operate Tolk compare with the cost of alternative resources in the region?

A At [redacted], the costs to operate Tolk are high relative to the cost of alternatives as shown in Table 7 and Table 8 below.[26] Because renewable generation and batteries do not have emissions, the cost estimates in the tables below do not include any NO_x emission costs. We know Tolk, however, will incur potentially increasing NO_x costs based on both the U.S. Environmental Protection Agency's ("EPA") existing Cross State Air Pollution Rule under the 2008 ozone standards, and the updated Good Neighbor Plan that the EPA just issued in March under the 2015 ozone air quality standard.

The current cost to build Solar PV in the southwest is between $15/MWh and $30/MWh. Building paired solar PV plus battery storage projects costs between $24.50/MWh and $33.55/MWh for the solar PV and between $5.36/kW-month and $10.99/kW-month for the battery storage. Tucson Electric Power Company ("TEP") also just brought online the 247 MW Oso Grande Wind project, which cost approximately $1,435/kW.[27]

[26] Tables 7 and 8 are not intended to reflect a comprehensive collection of alternative costs, but instead intended to be illustrative of recent alternative generation and storage costs in the region.

[27] Docket No. E-01933A-22-0107 before the Arizona Corporation Commission, Direct Testimony of Devi Glick, Pg. 19.

Table 7. Recent solar PV and wind power purchase agreements in the Southwest

Resource	Utility/ owner	State	Project size (MW)	$/MWh	Commercial operation date
AZ Solar 1	Central Arizona Project	AZ	30	$24.99	12/2020
Buena Vista 2 Solar	EPE	NM	20	$23.38	6/2023
AZ Solar 2	Central Arizona Project	AZ	20	Low $30's	12/2023
Hecate 1 Solar	EPE	NM	100	$14.99	6/2024
Hecate 2 Solar	EPE	NM	50	$18.93	6/2024

Direct Testimony of Devi Glick, NM Docket E-019331-22-0107; EPE Amended Application in NM PRC Case No. 22-00092-UT; Amended Application in NM PRC Case No. 19-00099-UT/ Case No. 19-00348-UT.

Table 8. Recent solar PV + battery energy storage system (BESS) projects

Resource	Utility/ owner	State	Project size (MW)	Price	Commercial operation date
Buena Vista 1 solar PV + battery storage	EPE	NM	Solar: 100 BESS: 50	Solar: $24.49/MWh BESS: $5.36/kw-month	6/2023
Arroyo solar PV + battery storage	PNM	NM	Solar: 300 BESS: 150	Solar: $18.65/MWh BESS: $7.46/kw-month	6 – 12/2023
San Juan solar PV + battery storage	PNM	NM	Solar: 200 BESS: 100	Solar: $33.55/MWh BESS: $9.56/kw-month	5/2024
Jicarilla solar PV + battery storage	PNM	NM	Solar: 50 BESS: 20	Solar: $19.73/MWh BESS: $9.97/kw-month	5/2023
Atrisco solar PV + battery storage	PNM	NM	Solar: 300 BESS: 300	Solar: $23.63/MWh BESS: $8.85/kw-month	5/2024
Carne solar PV + battery storage	EPE	NM	Solar: 130 BESS: 65	Solar: $29.96/MWh BESS: $10.99/kw-month	5/2025

Direct Testimony of Devi Glick, NM Docket E-019331-22-0107; EPE Amended Application in NM PRC Case No. 22-00092-UT; Amended Application in NM PRC Case No. 19-00099-UT/ Case No. 19-00348-UT; Motion of Public Service Company of New Mexico for approval of amendments to San Juan Generating Station replacement resource agreements and shortening response time, in NM PRC Case 19-00195-UT; Compliance notice of Public Service Company of New Mexico of Second Amendment to Atrisco Energy Storage Agreement in NM PRC Case No. 20-00182-UT.

Q How do these costs compare to the costs for alternatives that SPS modeled during its 2021 IRP /Tolk Analysis and its 2022 Tolk Analysis?

A Table 9 below shows the costs that SPS modeled in its most recent 2021 IRP in New Mexico as well as in its updated 2022 Tolk Analysis. Comparing SPS's projections from its analyses to the costs reported for actual projects in the region, as shown in Table 7 and Table 8 above, we can see that SPS's cost assumptions for battery storage are high and not in line with actual industry cost data. SPS indicated that it issued an RFP on November 28, 2022 to procure new resources for replacing several aging gas steam units. The Company should consider whether respondents to this RFP could replace some of the planned generation from Tolk. SPS should also consider placing new resources at the Tolk Plant to utilize the existing interconnection rights. Doing so could reduce interconnection costs and make the project eligible for additional energy community tax credits under the IRA.

Table 9. Confidential SPS New renewables cost assumptions from (assuming 2028 in-service year, excluding transmission adders)

Resource	2021 IRP LCOE ($/MWh) Nominal $	2022 Analysis LCOE ($/MWh) Nominal $
Wind	[redacted]	[redacted]
Solar	[redacted]	[redacted]
Battery	[redacted]	[redacted]

Source: SPS 2021 Integrated Resource Plan; SPS Response to Sierra Club Request 1-5, Exhibit SPS-SC 1-5(a)(i)(CONF); SPS Response to Sierra Club Request 1-5, Exhibit SPS-SC 1-5(a)(CONF), EO – T32-T28_PL_400TRX.xlsx; SPS Response to Sierra Club Request 4-3, Exhibit SPS-SC 4-3.

Q Do the renewable and battery storage costs shown in the Table 7 and Table 8 above reflect the near-term impact of inflation and supply chain challenges?

A Yes. The prices for the Buena Vista, Carne, Atrisco, and San Juan projects all reflect recent power purchase agreement ("PPA") amendments that the developers requested. These amendments increase the project cost to account for supply chain challenges and inflation (and in some cases also extend the online date).

Q Is there any indication that costs for renewables and battery storage have begun to stabilize and come back down?

A Yes. A report published by LevelTen Energy on July 17, 2023 found that solar power purchase agreement prices fell by around 1 percent across the United States in the second quarter of 2023, following three years of large price increases. The report goes on to state that the aggregate 1 percent decline is actually much larger in most parts of the country and was skewed upward by a 14 percent price jump in Texas due to legislative uncertainty.[28] This means that the cost to install solar PV in New Mexico should be declining.

Q Can clean energy portfolios paired with market energy provide the same level of reliability that SPS currently gets from Tolk?

A Yes, if deployed correctly, clean energy resources (including renewables, battery storage, and demand-side management programs) paired with market energy and transmission build-out, can provide the same if not better reliability than SPS's Tolk. Tolk has faced reliability challenges in recent years, as shown by the forced outage rates discussed above. Additionally, as outlined in detail below in this section, Tolk as well as other regional coal plants have faced challenges procuring the full contracted amount of coal. If a plant does not have a firm and certain fuel

[28] Emma Penrod, *Solar PPA prices drop for first time since onset of COVID-19: LevelTen,* Utility Dive (July 18, 2023), *available at* https://www.utilitydive.com/news/solar-wind-renewable-energy-ppa-prices-levelten/687881/?utm_source=Sailthru&utm_medium=email&utm_campaign=Issue:%202023-07-18%20Utility%20Dive%20Newsletter%20%5Bissue:52691%5D&utm_term=Utility%20Dive.

supply, then it cannot be relied on to provide its full firm capacity and should be de-rated.

With renewables, on the other hand, there are zero fuel requirements and therefore no possibility that a fuel supply constraint will disrupt firm capacity. The output of solar PV also aligns well with SPS's peak summer demand needs. And with transmission reform underway across the United States, it may become easier and less costly for SPS or other regional entities to build out the transmission network needed for SPS to access high quality wind. While it is true that SPS will also need firm capacity, battery storage can provide firm capacity and many of the grid services currently provided by SPS's fossil resources. Additionally, SPS just received approval last year to convert the three Harrington coal units to gas, which provide 1,050 MW of firm capacity that the Company is planning to keep online well beyond 2030. I am not suggesting that SPS retire the Tolk units immediately and replace them with energy market purchases or energy efficiency measures. But, if implemented correctly, and based on adequate reliability assessments, SPS could replace some or all of the Tolk capacity with a combination of resources with equal or possibly better reliability performance.

Q What costs would SPS avoid by retiring Tolk in 2028 rather than in 2032?

A SPS would avoid several years' worth of sustaining capital expenditures, environmental capital expenditures, O&M costs, and NO_X compliance costs with early retirement of Tolk. Specifically, the Company would avoid all the costs it would incur to keep the plant online between 2028 and 2032. While SPS has projections of the costs required to maintain the plant, the longer the plant stays online the higher the risk that something will break or a new environmental regulation will be enacted that increases the cost to maintain the plant beyond what SPS projected. For example, SPS's current analysis does not include the costs associated with Good Neighbor Rule compliance, which the EPA just finalized in March. As I discuss later, compliance with the Good Neighbor Rule will require either operation at very low levels, investment in costly environmental upgrades, or else the purchase of expensive NO_X emission credits. As shown in Table 10, SPS projects that it will spend $126 million on O&M and capital expenditures at Tolk between 2029 and 2032.

Table 10. Confidential SPS projected costs 2029–2032

(2022 M $)	**O&M**	**Capital expenditures**	**NO_X costs**	**Total**
Tolk 1	[redacted]	[redacted]	NO_X compliance costs not included in modeling	[redacted]
Tolk 2				
Total	[redacted]			[redacted]

Source: SPS Response to Sierra Club Request 1-5, Exhibit SPS-SC 1-5(a)(i)(CONF); SPS Response to Sierra Club Request 1-5, Exhibit SPS-SC 1-5(a)(CONF), EO – T32-T28_PL_400TRX.xlsx.

ii. ***<u>SPS's 2022 Tolk Analysis supports accelerating the retirement date of Tolk from 2032 to 2028, at the latest; but the near-term increase in coal generation and long-term increase in gas capacity that SPS's modeling shows as replacing Tolk's energy and capacity is concerning.</u>***

Q **Why did SPS conduct an updated analysis of Tolk for this docket?**

A The aquifer that Tolk relies on for cooling water, the Ogallala aquifer, is being depleted faster than it can be recharged. SPS explained in the prior rate case, Case No. 49831, that it can no longer economically access water sufficient to operate the plant through its original retirement date in the 2040's. In Docket No. 51802, SPS received approval (through a stipulated settlement) to move the plant's depreciation rate to correspond to 2034 end-of-life.

SPS implemented the Tolk Optimization Plan, and starting in the spring of 2018, SPS began reducing output from the units in the off-peak (October–May) months to conserve water. Then in early 2021, SPS installed synchronous condensers at the units to enable the units to provide voltage support to the system during months when Tolk wasn't supplying generation to the grid. SPS presented this as the Tolk Optimization Plan in which it would operate the units during peak summer months (June–September) when their capacity was needed and take the plant offline during the off-peak months.[29]

In testimony in the present case, SPS acknowledges that it has continued to use Tolk during off-peak months as a generator during extreme weather events, and recently in response to high gas prices.[30]

In the current rate case application, SPS indicates that water availability has not materially changed, but the economics of operating Tolk and the economics of building replacement resources have changed with last year's natural gas price spike and the passage of the IRA.[31]

Q What analysis has SPS conducted to support its application to accelerate the retirement date of Tolk from 2032 to 2028?

A SPS created the 2022 Tolk Analysis using the EnCompass model to evaluate two alternative scenarios: continuation of the (commission approved) Current Tolk Optimization Plan with conservation mode operations and retirement in 2032, or a Modified Tolk Optimization Plan with increased year-round operations and

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[29] Direct Testimony of Ben Elsey, Pg. 39.

[30] *Id.*, Pg. 40.

[31] *Id.*, Pg. 40.

retirement of the plant in 2028. In this analysis, SPS is essentially modeling a set quantity of MWh remaining over the life of Tolk as a proxy for the remaining water—that is, SPS has sufficient water to either operate Tolk at increased output levels year-round for a shorter number of years, or at reduced annual output levels for a longer period.

SPS tested two scenarios:

1. Current Tolk Optimization Plan: SPS ramps up operations at Tolk year-round through 2028. SPS placed an annual generation limit of 4,000 GWh on Tolk.

2. Modified Tolk Optimization Plan: SPS operates Tolk with reduced annual output through 2032. SPS placed an annual generation limit of 2,400 GWh on Tolk.

Q Why did SPS evaluate only these two scenarios?

A SPS indicated that 2028 is the earliest feasible retirement date for the Tolk units given the time needed to procure replacement resources, therefore it did not model retirement before 2028. Based on the water limitations, SPS cannot operate Tolk cannot beyond 2032 even assuming reduced operations, so the Company did not test operation beyond 2032. SPS has no explanation in its testimony as to why it did not evaluate the scenario in which Tolk operates at reduced levels until retirement in 2028. Reducing operations at the Tolk plant by dispatching the plant economically, with a dispatch cost that reflects the future cost of NOx emission credits, should be the lowest cost option for ratepayers.

Q How did SPS describe its findings from the updated 2022 Tolk analysis?

A SPS Witness Elsey stated that SPS estimates customers will save approximately $109 million between now and 2042 if Tolk is retired by 2028 under the Modified Tolk Optimization Plan (compared to retirement in 2032 under the Current Tolk Optimization Plan).[32] He attributed this to the value Tolk provides of continued flexible operation as higher gas prices and the lower expected cost of replacement generation enabled by the passage of the IRA.[33] In other words, SPS wants to ramp up operations of Tolk, and thus use up a substantial portion of Tolk's remaining water, while gas prices are high.

Q Please summarize your findings from reviewing SPS's modeling results from the 2022 analysis?

A SPS's 2022 Tolk Analysis shows that the Modified Tolk Optimization Plan will save ratepayers $119 million on a present value revenue requirement ("PVRR") basis between 2023–2042, and $66 million between just 2023 and 2028 relative to the Current Tolk Optimization Plan. SPS's modeling results show a substantial build-out of renewables over the next two decades to meet load growth and meet SPP's new reserve margin and capacity accreditation requirements. But, when Tolk is retired specifically, SPS's modeling shows very little incremental battery storage capacity coming online to replace the Tolk Plant, and instead it shows a large build-out of new gas capacity.

Critically, SPS did not evaluate a scenario where Tolk operates in conservation mode and retires in 2028.

[32] Direct Testimony of Ben Elsey, Pgs. 43-44.

[33] *Id.*, Pgs. 42, 46.

Under the Modified Tolk Optimization Plan, SPS brings online an incremental 933 MW of gas peaking resources, and only 80 MW of solar PV, 140 MW of Wind, and 40 MW of battery storage to replace Tolk between 2027 and 2029. These capacity additions are relative to what the model adds during the same timeframe in the Current Tolk Optimization Plan.

In the Current Tolk Optimization Plan, SPS once again brings online an incremental 933 MW of gas peaking resources, and also adds 230 MW of wind and 140 MW of battery storage to replace Tolk between 2030–2033. This is relative to what the model adds during the same timeframe in the Modified Tolk Optimization Plan.

Q How does SPS replace the energy from Tolk in each scenario?

A In the Modified Tolk Optimization Plan, as I would expect with an increase in year-round operation, SPS's generation from coal increases before Tolk retires in 2028 (relative to the Current Tolk Optimization Plan). Generation from SPS's existing steam gas units is displaced by the coal generation and is therefore lower over this same timeframe. After Tolk retires in 2028, SPS relies on generation from new combustion-turbine units to replace much of the generation from Tolk. The Company's overall generation from renewables is higher over the planning period, and purchases are lower in the 2023–2028 timeframe.

In the Current Tolk Optimization Plan, generation from SPS's existing gas resources replace much of the coal generation during the off-peak months and therefore SPS's overall generation from gas is higher. Even though the timing is different, total generation from coal is about the same across both scenarios. Because of this, cumulative CO_2 emissions are also very similar in both scenarios.

Q How much is Tolk utilized in each scenario?

A As shown in Figure 1 below, Tolk's utilization is projected to remain low and at current levels (around 25 percent) in the Current Tolk Optimization Plan. In the Modified Tolk Optimization Plan, SPS projects Tolk's utilization will jump back up to above 40 percent, based on SPS's speculation that gas prices will remain high.

Figure 1. Tolk's historical and projected capacity factor

Source: SPS Response to SC 1-6(a-f), Exhibit SC 1-6(a-f); SPS Response to Sierra Club Request 1-5, Exhibit SPS-SC 1-5(a)(CONF), EO – T32-T28_PL_400TRX.xlsx

Q How did the results of SPS's 2022 analysis differ from SPS's results in the Company's prior Tolk and IRP analyses?

A Because of the change in SPP's reserve margin and capacity accreditation, SPS needs more capacity overall in its 2022 Analysis than when it did its 2021 Analysis. Specifically, in the updated modeling SPS adds a little over 5,000 MW (nameplate) more resources between 2023–2041 than it did in its 2021 Tolk

Analysis. This breaks down to about 1,000 MW of battery storage, 4,000 MW of wind, and 500 MW of firm gas peaking capacity.

To replace Tolk specifically, SPS's 2021 modeling results showed the addition of around 1,400 MW of gas capacity, 40 MW of battery storage, and 730 MW of solar between 2030 and 2033. This is compared to 933 MW of gas peaking resources, 230 MW of wind, and 140 MW of battery storage during the same timeframe in the 2022 analysis.

Q Do you have any concerns with the assumptions or results of SPS' 2022 Tolk Analysis?

A I am concerned that SPS has been focusing, and continues to focus, its Tolk analysis on which fossil resource (coal or gas) is the most expensive at the moment instead of focusing on how it can accelerate the retirement of Tolk and replace it with lower-carbon alternatives. By focusing on this short-term dynamic, SPS has now all but locked itself into reliance on Tolk and volatile fossil fuels for several more years as it procures new resources. SPS should focus on procuring replacement resources, and in the interim, SPS should seek to minimize operations at the plant to conserve water, reduce emissions and costs, and preserve optionality. The Company can do this by operating the plant economically based on a market bid that includes the full cost of NOx emission credits.

In SPS's 2021 Tolk Analysis, the Company found that the most economic option was to continue operating Tolk at reduced annual output levels to conserve water and capacity, and to ramp up generation from its gas units. Now, in its 2022 Tolk Analysis, SPS found that with higher gas prices, it costs less to instead ramp up generation from the Tolk coal plant and reduce SPS's reliance on its now high-priced gas resources. Incidentally, some of that gas would have come from Harrington, which SPS recently fought for approval to convert from coal to gas.

Despite this struggle to mitigate reliance on natural gas resources, the Company's modeling shows only 50 MW of storage coming online before 2030. And while the modeling does show a large build-out of 1,119 MW of solar PV and 3,810 MW of wind before 2030 (most of which is to serve load growth and not directly replace Tolk), it also shows an addition of 1,400 MW of gas resources between 2026 and 2030. The Company's plan to continue its strong reliance on gas is especially concerning for two reasons: First, SPS's near-term decision to accelerate the retirement of Tolk was driven precisely by the desire to reduce reliance on high-priced, and highly volatile natural gas, yet SPS plans to make itself more reliant on natural gas and more exposed to that volatility. Second, the generating units that SPS plans to add between 2026 and 2030 would ordinarily have a useful life of 30 years, putting them in service through the mid-2050s. But New Mexico has a statute in place that requires utility portfolios to be carbon free no later than 2045. SPS is therefore planning to acquire new resources which will become "stranded assets" two-thirds of the way through their initial useful lives.[34]

As stated above, what SPS should be doing is reducing its reliance on *both* (1) gas resources that rely on volatile and costly fuel inputs, and (2) high emission coal plants facing myriad future costs and risks from water availability and increasing environmental regulations.

[34] While it is true that most of SPS's customer loads are in Texas, the zero-carbon standard in the New Mexico Renewable Energy Act specifically prohibits re-assigning/re-designating carbon emitting resources as a means of complying with the standard.

Q How will EPA's recently proposed regulations under Section 111(b) and (d) of the Clean Air Act impact SPS's modeling results?

A If finalized as proposed, EPA's proposed 111(b) regulations will make continued reliance on natural gas resources more expensive than it was in the past. Specifically, under 111(b) all new gas-fired plants that plan to operate between 20 and 50 percent capacity factors (gas turbines and combined cycle plants) must co-fire at least 30 percent on hydrogen by 2032. All new gas-fired plants that expect to operate at capacity factors above 50 percent (combined-cycle and simple-cycle combustion turbines) must either install carbon capture and sequestration technology that captures 90 percent of CO_2 emissions by 2035, or co-fire with hydrogen 30 percent by 2032 and 96 percent by 2038. This requirement will substantially change the cost to SPS and operational parameters of continuing to rely on gas.

Under Section 111(d) of the Clean Air Act, EPA has proposed regulations that would limit GHG emissions from existing sources like Tolk. For existing power plants that expect to operate past December 31, 2039, EPA's proposal would require the installation and use of carbon capture and sequestration technology with a 90 percent capture efficiency. For sources operating past 2031, but which commit to cease operations before 2039, EPA's proposal would require existing generators to co-fire with 40 percent natural gas. Existing sources may avoid retrofits or emission reduction measures if they commit to retiring either before (1) December 31, 2031, so long as those units maintain current emission rates, or (2) December 31, 2034 if they agree to limit their capacity factors to 20 percent or less after 2030.

Q Did SPS test a scenario assuming Tolk retired in 2028 and reduced annual operations based on economic dispatch between now and retirement??

A No, SPS did not. SPS limited its analysis to scenarios that utilized all remaining, economically accessible water. *But by not analyzing a Retire 2028 scenario with reduced annual operations SPS is providing the Commission with an incomplete set of modeling results.* More specifically, SPS is not providing the Commission with all the information it needs to determine whether one of the two scenarios it put forward is actually the least-cost scenario for ratepayers. Reducing operations at the Tolk plant by dispatching it economically, with a market bid that reflects the full variable cost, including future cost of NOx emission credits, should be the lowest cost option for ratepayers.

Q Why do you think a scenario assuming retirement in 2028 and reduced annual operations could be a better option for SPS's ratepayers, especially assuming current and updated input assumptions?

A Continuing to operate Tolk with reduced operations can reduce costs and risks for ratepayers in several ways. First, gas prices have fallen relative to where they were when SPS conducted the 2022 Tolk Analysis (as I will discuss below), therefore reduced annual operations likely makes sense again with lower gas prices. Second, current and future environmental regulations, including the Good Neighbor Rule which the EPA finalized in March, are likely to make operations at Tolk more costly than SPS currently anticipates. SPS needs to model the full NOx emission costs to understand how Tolk will be economically dispatched with implementation of the Good Neighbor rule. Third, reducing utilization will reduce CO_2 emissions and other environmental impacts. Finally, conserving water at Tolk will reduce the risk associated with water levels falling faster than anticipated. It will give SPS the ability to rely on the plant if the Company faces challenges procuring replacement resources on the necessary timeline (such as Public Service Company of New Mexico ("PNM") faced in replacing the San Juan Generating Station).

Q Did SPS model Tolk operating with economic dispatch in its 2022 Tolk Analysis?

A Yes, but the Company did not include full and up-to-date costs incurred to operate the plant, including the cost of NOx emission credits under the Good Neighbor Rule. In the contested stipulation from SPS's recent New Mexico rate case, Cause No 22-00286-UT, SPS agreed to economically commit the Tolk units, and to limit self-commitment of the Tolk generation units to any required testing, reliability concerns and safety and/or maintenance.[35] Outside of those occasions, SPS must include all variable costs of operation, including NOx emission costs, when bidding its units into the SPP market.

To operate Tolk at the higher capacity factor shown through 2028 and comply with the Good Neighbor rule, SPS will need to purchase volatile and expensive NOx credits. As a result, the actual costs of dispatching Tolk will very likely be greater than the costs SPS modeled in its 2022 Tolk Analysis. Since SPS chose to not dynamically include these compliance costs in its modeling, a lower annual generation cap, such as what SPS included in the Current Tolk Optimization Plan, can be viewed as a reasonable proxy mechanism for modeling economic dispatch but with full NOx emissions costs.

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[35] Southwestern Public Service Company's Contested Comprehensive Stipulation in Case No. 22-00286-UT, Pg. 8.

Q Based on SPS's modeling, can you estimate what it would look like if SPS economically dispatched Tolk based on the full cost to operate the unit and retire the plant at the end of 2028?

A Yes. Based on the results of the two scenarios that SPS modeled I can estimate the revenue requirement and emissions impacts of economically operating the plant assuming high NOx emission costs drive reduced annual operations, and assuming early retirement. Specifically, before 2028, I can look at the generation mix and resource additions from the Current Tolk Optimization Plan to see how Tolk operates under reduced annual operations – this can serve a proxy for reduced generation levels I expect to see at Tolk when it is bid into the market economically with a dispatch cost that includes high NOx emissions credit costs. After 2028, I can look at the generation mix and resource additions from the Modified Tolk Optimization Plan to see how Tolk's capacity and energy was replaced when it retires.

Combining these results, I find that maintaining reduced operations in line with the Current Tolk Optimization Plan and retiring Tolk in 2028 reduces CO_2 emissions by around 6 percent relative to the scenarios SPS tested. It is also less costly than the currently authorized Tolk Optimization Plan with a 2032 retirement date, and only marginally more costly than SPS's proposed Modified Tolk Optimization Plan, as shown in Table 11 below. Specifically, I find that reducing annual operations will be at most $66 million more expensive (0.5 percent of total costs), based on SPS's own modeling results.

But these results are outdated and likely overstate the cost of this scenario. Specifically, with updated natural gas prices, NO_X emission costs, and other environmental compliance costs included, that cost difference should drop significantly and will likely be eliminated.

Table 11. Difference in NPVRR across retirement and operational scenarios

Retire date	Operations	2023–2028		2023–2032		2023–2042	
		NPV ($M)	Delta ($M)	NPV ($M)	Delta ($M)	NPV ($M)	Delta ($M)
2032	Current Tolk Optimization Plan	$5,119	$66	$7,680	$44	$12,507	$119
2028	Modified Tolk Optimization Plan	$5,053	$0	$7,636	$0	$12,389	$0
2028	Current Tolk Optimization Plan	$5,119	$66	$7,701	$66	$12,454	$66

Source: Calculated based on SPS Response to Sierra Club Request 1-5, Exhibit SPS-SC 1-5(a)(CONF), EO – T32-T28_PL_400TRX.xlsx

If SPS re-ran the EnCompass model with updated cost and price assumptions, including (lower) gas prices and NOx emission costs, and evaluated how these changes impact both the capacity expansion and resource dispatch, it should find that economically committing and dispatch Tolk with a dispatch cost that includes NOx emission credits, and retiring the plant by 2028, is very close in cost, and perhaps less costly, than the Modified Tolk Optimization Plan with year-round operations and early retirement.

Q Given the minimal cost difference under updated assumptions, should SPS be making this decision based strictly on the results from its EnCompass model runs or should it consider other factors and risks?

A Given the minimal difference I found when evaluating the cost of switching between reduced operations under the Current Tolk Optimization Plan and full annual operations under the Modified Tolk Optimization Plans (assuming a 2028 retirement date), and the necessary updates listed above that will reduce and likely even eliminate the cost differences between these two scenarios, SPS should be considering other realistic and practical factors to guide its retirement decisions.

This practice of considering other real-life factors has been supported by SPS in the past. The Company relied on non-quantitative factors to support its resource requests in Docket 21-00200-UT where the conversion of Harrington Units 1–3 from coal to gas was at issue. SPS advocated for the conversion of all three units to gas despite its analysis showing that converting only two was marginally lower cost. The Company cited qualitative factors in making this decision. Company Witness Koujak, SPS's Independent Evaluator, stated:

> "I always have to scrutinize these numbers more qualitatively and what could drive potential differences…when we say 'What is the best scenario,' it is not just what these numbers show or what the model has put out, I would look to other qualitative factors.'…I guess I'm saying there are factors to consider other than economic factors."[36]

The Commission accepted this argument, with the Proposed Commission Order referencing Company Witness Elsey in stating "there being no actual difference, real life (qualitative vs quantitative) concerns must be considered."[37] The non-quantitative factors in that prior case were risk and optionality, which would also be implicated by a decision to minimize reliance on Tolk between now and its retirement in 2028. As I have discussed in this testimony, the more Tolk is used, the more likely it is that the plant will experience a material, unanticipated equipment failure or depletion of water resources. SPS needs Tolk for peak month capacity until 2028, so if there was major equipment failure during this interim period, SPS (and its ratepayers) could be put in the position of having to make a

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[36] Exhibit DG-3, Transcript from February 16, 2022 in Case No. 21-00200-UT, Pgs. 365-6.

[37] Recommended Decision from April 1, 2022 in Case No. 21-00200-UT, Pg. 12.

very expensive repair or capital improvement to a plant which had only a handful of years of life remaining.

Q Is SPS proposing direct replacement resources for Tolk, and to meet its other future resource needs, in this docket?

A No. SPS is not seeking approval for specific replacement resources—it is only seeking approval to accelerate the retirement and depreciation date for the Tolk plant. But I am concerned that the modeling results that SPS provides here are indicative of the modeling results it will present in the upcoming IRP docket. If the Company is showing a portfolio that relies heavily on gas and builds out very minimal battery storage in the near term, I have no reason to believe the Company will utilize fundamentally different assumptions and come to different conclusions when conducting its resource planning modeling later this year.

Q What takeaways do you have about SPS's proposal to increase year-round operations at Tolk and move up the plant's retirement date to 2028?

A Tolk is an aging legacy power plant that will only become more costly and risky to operate as it ages. SPS should commit to retiring the unit by 2028 and minimize additional capital investments in the plant in the time between now and when it retires. Additionally, SPS should seek to minimize the plant's operations by bidding it into the market with a cost that reflect the full cost to operate the unit (including the cost of NOx emission credits) rather than modifying the Plan to ramp up year-round operations and use up all the water between now and 2028. Given that there are only marginal, if any, savings from modifying the Tolk Optimization Plan to ramp up operations year-round (assuming a 2028 retirement date), and there are real risks that running the plant more hours could result in major failure or accelerated depletion of water resources, the lowest risk course of action is to continue reduced operations for Tolk through a 2028 retirement. Specifically, SPS should conserve the remaining water—which will minimize costs and emissions and reduce the chance that SPS will run out of water at Tolk, or experience a plant breakdown, before it has replacement resources online.

iii. SPS should update key inputs, notably gas prices, and better reflect the potential risks associated with continued reliance on coal generation in its ongoing cost assumptions.

Q Do you have any concerns with the input assumptions that SPS relied on for its Tolk analysis?

A Yes. I am concerned that SPS's water availability may become even more limited than currently anticipated, and that by ramping up operations in the near term SPS risks running out before it has replacement resources in place. I am also concerned that the Company's gas price forecasts (and market price forecasts) are already out of date, its battery storage costs overstate the cost to install battery storage in the near term and its coal prices do not reflect potential future fuel cost volatility and supply availability challenges. Finally, I am concerned that the additional environmental compliance measures, including the Good Neighbor Rule that the EPA just finalized, will further increase the cost to maintain and operate Tolk. I will explain each of these factors in detail below.

Q Explain the risks of water scarcity and availability and how SPS has taken this risk into account in its modeling and analysis.

A The accelerated retirement of Tolk is being driven by its diminishing water supply in the Ogallala aquifer that SPS relies on for cooling water. SPS has known for several years that it cannot operate the plant at full output, year-round through its original retirement date in the 2040s. SPS's current projection is that it has enough water to operate at reduced output levels under the Current Tolk Optimization Plan through 2032 or, at increased output levels under the Modified Tolk Optimization Plan through 2028.

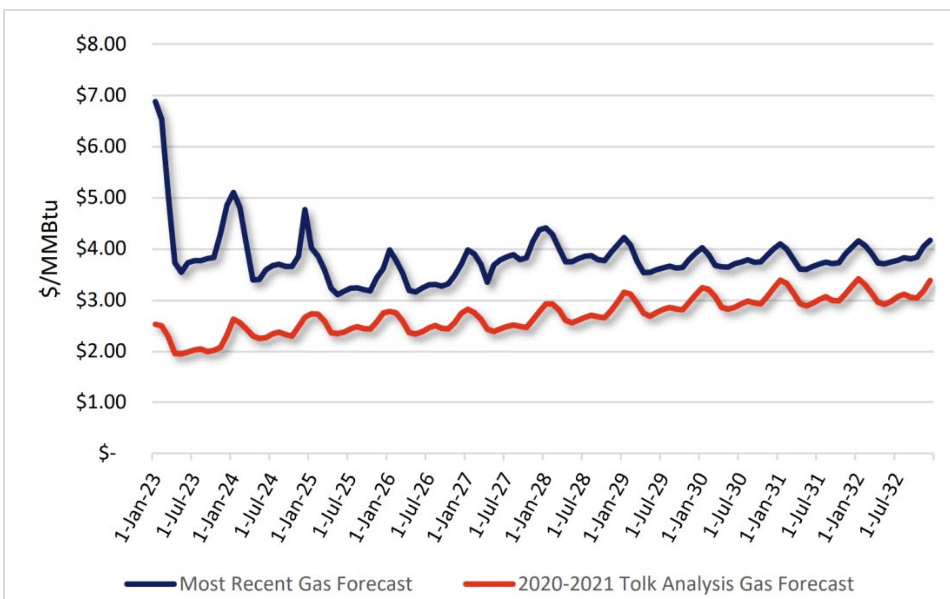
SPS inappropriately approaches its economic analysis as if water withdrawal pacing is certain or predictable. It isn't. Specifically, SPS's modeling assumes that (1) it will cost the same amount to withdraw the water it needs under the Current Tolk Optimization Plan with reduced operations over the next decade as it will to withdraw the water it needs under the Modified Tolk Optimization Plan with increased year-round operations over the next five years; and (2) the same quantity of water will be available regardless of whether its withdrawn now or in five years. While these superficially appear to be reasonable simplifying assumptions, they rely on the premise that SPS's current projections about water availability are accurate, and that the agricultural users that withdraw the majority of the water from the aquifer will not exceed their assumed withdrawal level. In reality, there is a higher risk associated with keeping the plant online longer that is not captured in SPS's analysis: the longer SPS plans to keep the plant online, the higher the risk that the water will be depleted faster than projected.

Additionally, by using up the water faster in the near term SPS is precluding its ability to rely on the plant should it face challenges bringing replacement resources online in time. This is especially concerning given that (1) the Company did not present any analysis showing that increased year-round operation under the Modified Tolk Optimization Plan (assuming retirement in 2028) was lower cost than reduced operation under the Current Tolk Optimization Plan (also assuming retirement in 2028), (2) my analysis showed it would at worst be only marginally more expensive and could likely even be less expensive for SPS to maintain reduced operations at the plant and retire in 2028 compared to Modifying the Tolk Optimization Plan to ramp up operations and retiring in 2028.

Q Discuss the changes in natural gas prices and volatility in recent years.

A SPS relied on a gas price forecast for its Tolk modeling which is already out of date, and higher than other leading sources currently project. Figure 2 below shows the gas prices SPS modeled in its 2022 analysis compared with the gas price forecast it used in its original 2021 analysis. SPS's 2020–2021 forecast is more in line with industry-leading forecasts than the one it used for its 2022 analysis.

Figure 2. SPS's natural gas price forecast comparison



Source: Figure BRE-1: Natural Gas Price Forecast Comparison.

SPS recently released its Spring 2023 Henry Hub forecast which shows a dramatic decline in near-term cost projections. Specifically, as shown in Figure 3, SPS's 2023 forecasts shows near term (2023–2024) prices forecasted at about half the level SPS forecasted in its 2022 forecast.[38]

Figure 3: CONF SPS Henry Hub price forecasts for 2022 and 2023

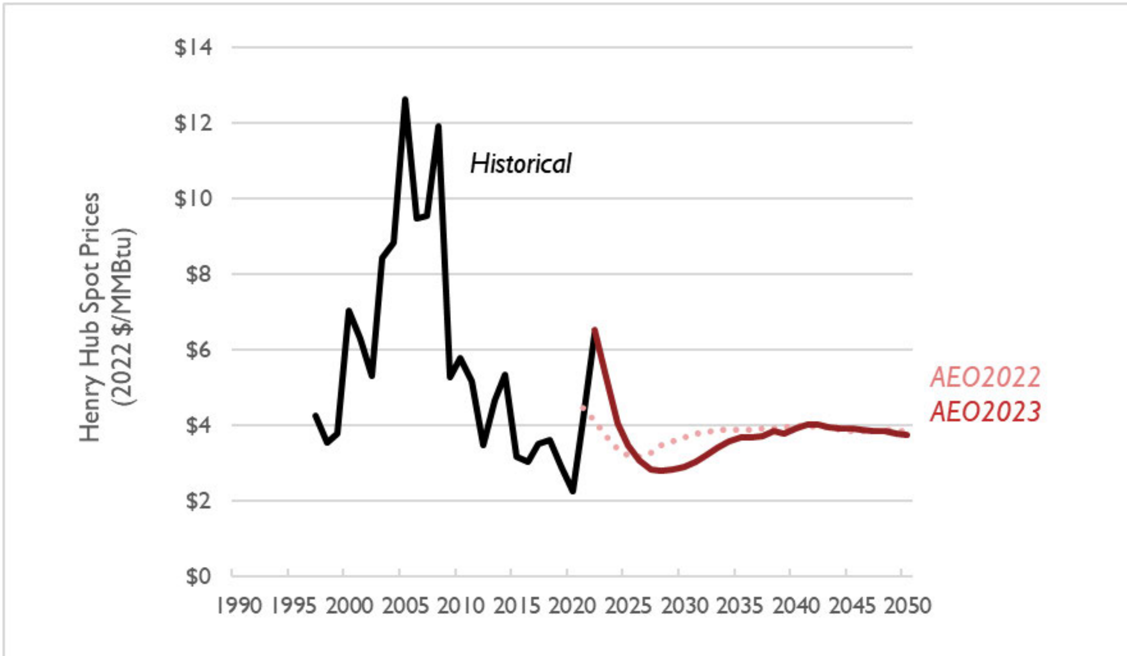
[redacted]

Source: SPS Response to SC 1-8, Exhibit SPS-SC 1-8.3(V)(CONF); SPS Response to TIEC 1-11 (SUPP1), Exhibit SPS-TIEC 1-11(SUPP1).

Additionally, as I show in Figure 4 below, even though gas prices increased substantially last year, they dropped significantly in recent months. Similar to what SPS projects, current (2023) forecasts from leading industry sources are projecting even lower prices than previously projected. The U.S. Energy Information Administration (EIA) published its most recent Annual Energy Outlook (AEO) in March, which included an updated gas price forecast. The EIA projects slightly higher prices in the immediate near term (as markets recover from the 2022 price spikes), but then a settling in gas prices below where it has projected in its 2022 forecast.

[38] SPS Response to SC 1-8, Exhibit SPS-SC 1-8.3(V)(CONF); SPS Response to TIEC 1-11(SUPP1), Exhibit SPS-TIEC 1-11(SUPP1).

Figure 4. U.S. Energy Information Administration gas price forecasts



Source: U.S. Energy Information Administration, Annual Energy Outlook 2023.

Q How does the IRA change the tax credits available to SPS for clean energy resources?

A As SPS acknowledges, the IRA provides additional tax credits for solar PV and wind, and new tax credits for battery storage that were not available previously (previously only paired battery storage was eligible). The IRA added new Investment Tax Credits ("ITC") and Production Tax Credit ("PTC") tiers that entitle any solar, wind, or battery storage project to a 10 percent adder if the projects are located in an energy community. Any census tract where a coal mine or coal-fired power plant has closed since 2009 is defined as an energy community (as well as the census tracts directly adjacent). Additionally, brownfield sites and areas where fossil fuels have (1) accounted for at least 0.17 percent of direct employment or (2) 25 percent of local tax revenues and where the unemployment rate is above the national average for the previous year qualify as energy communities.[39] If SPS sites new renewables at the Tolk plant it should qualify for the energy community adder, but it is not clear that the Company included this assumption in its modeling.

Q Explain your concerns with the battery storage cost assumptions that SPS modeled.

A SPS's modeling shows no new battery storage until 2029. This is not surprising because its cost assumptions were very high in the near term. Specifically, the Company was modeling battery storage costs before 2029 that were more than double its cost assumptions for battery storage after 2029. SPS acknowledged in discovery that it had incorrectly modeled battery storage prior to 2029.[40] The Company provided updated total NPV results for one scenario but did not provide updated modeling outputs for us to evaluate. It is unclear if the model added additional battery storage before 2029 with the updated cost assumptions.

Q Explain the risk of coal supply availability that SPS faces at Tolk.

A The risk of coal supply availability stems from challenges facing both coal suppliers themselves and the railroads that transport the coal.

Many regional coal plants have retired or are planned to retire, including the Navajo Generating Station in Arizona (closure in 2019), the San Juan Power Station in New Mexico (final unit shut down in 2022), and the Cholla Power Plant which plans to shut down in 2025. Harrington is ceasing operation on coal this year as well. This is driving down the demand for coal in the region.

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[39] 26 U.S.C. § 45(b)(11)(B).

[40] SPS Response to Sierra Club Request 4-3(a).

Individual coal mines are facing challenges delivering the required quantities of coal. Specifically, Public Service Company of New Mexico ("PNM") had to de-rate the San Juan Generating Station in 2022 because the coal mine was unable to supply the contracted quantity.[41] The co-owners had to de-rate their ownership shares to ensure the coal supply would last until the unit shut down, eventually at the end of September 2022.[42]

Coal transportation companies have also caused reliability challenges by failing to deliver contracted quantities of coal. SPS indicated that its coal supply was impacted by railway workforce shortages as well starting in July of 2022 and extending through the present. Specifically, SPS said:

> All Class 1 Railroads suffered a nationwide deterioration of services during July. Rail service delays were caused by severe crew shortages and equipment issues. Inventory levels at both the Tolk and Harrington plants dropped below optimal level in July 2022 and remain below targeted level.[43]

In addition, the Burlington Northern Santa Fe Railroad ("BNSF") that delivers coal to many regional plants, notified Tucson Electric Power ("TEP") in the spring of 2022 that it would not be able to meet its 2022 delivery obligations due to "lack of workforce availability." As a results, TEP had to de-rate the capacity of the capacity of the Springerville Generating Station.[44]

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[41] Direct Testimony of Devi Glick, Docket Number E-1933A-22-0107, Pg. 22.

[42] *Id.,* Pg. 22.

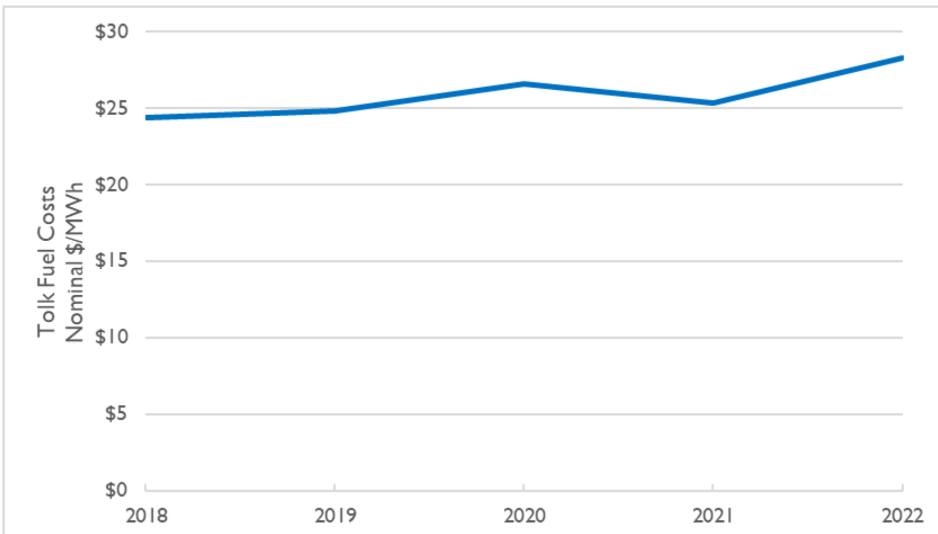
[43] SPS Response to Sierra Club Request 1-25, Schedule E-3.3.

[44] Direct Testimony of Devi Glick, Docket Number E-1933A-22-0107, Pg. 22.

Q Explain the risk of high coal prices and price volatility.

A SPS's coal costs have gone up around 12 percent over the last year after remaining virtually flat for the prior five years, as shown in Figure 5 below. While this roughly aligns with inflation, coal prices more broadly have faced volatility and uncertainty.

Figure 5. Average cost of coal (2018–2022)



Source: SPS Response to Sierra Club Request 1-6, Exhibit SPS-SC 1-6(g-i).

The price of coal went up substantially in some parts of the country over the last year, as shown in Figure 6 below, after staying relatively stable for the past decade. While this price spike specifically is something no one predicted, it is exactly the type of risk inherent in a system that relies on fossil fuel resources and that can be mitigated by a transition to clean energy resources.

Figure 6. Historical coal prices by region, 2011 to present

Source: SNL Energy, as shown on the U.S. Energy Information Administration website, available at *https://www.eia.gov/coal/markets/.*

SPS relies on Powder River Basin coal, which had fairly stable prices in 2021 and 2022. But there is no guarantee that they will stay that way going forward. Additionally, as discussed above, stable prices in the Power River Basin do not necessarily translate to a stable supply of coal delivered to the Tolk Generating Station. SPS indicated that it has currently contracted for the coal it needs through December 31, 2027, but that still leaves at least one year of fuel supply that it does not have under contract.[45] And as discussed, there is the ongoing potential for disruptions in supply.

Based on these factors, I am concerned that the coal prices that SPS relied on understate the future cost and risk of continuing to rely on coal.

[45] SPS Response to Sierra Club Request 1-25(a).

Q Explain the risk posed by future environmental regulations.

A There are a variety of environmental regulations that EPA has issued or is considering which would increase the cost to operate fossil fuel power plants. The most prominent action is EPA's rulemaking for cross-state ozone pollution (also known as the "Good Neighbor Plan"). Additional EPA actions include (1) the review of the state implementation plan for Texas under the Clean Air Act to implement the Regional Haze Rule; (2) the January 2023 proposed decision for the reconsideration of the national ambient air quality standards for particulate matter ("PM"); and (3) the proposed Greenhouse Gas Standards and Guidelines for Fossil-Fuel-Fired Power Plants under Section 111 of the Clean Air Act. Each of these actions by EPA has the potential to require significant pollution reductions at coal plants.

Q Please describe the Good Neighbor Rule.

A In March 2023, EPA issued a final regulation called the Good Neighbor Plan. Under the *Clean Air Act* ("CAA"), EPA must set National Ambient Air Quality Standards ("NAAQS") for ground-level ozone, which harms human health. The CAA includes a "good neighbor" provision that requires states (or, where the state fails, EPA) to regulate upwind sources that significantly contribute to, or interfere, with downwind states' noncompliance with the NAAQS.[46]

In 2015, EPA updated the national ozone standard, triggering Texas's obligation to eliminate pollution from sources such as Tolk and other Texas coal plants that contribute to downwind nonattainment. Because Texas and several other states

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[46] *See* U.S. EPA*, EPA's "Good Neighbor" Plan Cuts Ozone Pollution – Overview Fact Sheet*, *available at* https://www.epa.gov/system/files/documents/2023-03/Final%20Good%20Neighbor%20Rule%20Fact%20Sheet_0.pdf.

failed to submit lawful good neighbor plans of their own, EPA was required to issue a federal plan.

EPA's plan, like the Cross-State Air Pollution Rule under the 2008 ozone standard, requires many coal units to reduce NO_X emissions by either installing selective catalytic reduction ("SCR") controls or purchasing pollution allowances. Sources may also opt to retire. Although the Fifth Circuit Court of Appeals recently stayed the Good Neighbor Plan for Texas pending judicial review, it is likely Texas power plants will face additional NOx costs regardless of the outcome of the litigation, for two reasons: (1) the Clean Air Act requires upwind states like Texas to reduce emissions where sources within the state contribute to downwind nonattainment in other states, as Texas sources do; and (2) the Supreme Court upheld the Good Neighbor Plan's predecessor, the Cross State Air Pollution Rule, which was structured very similarly.

Q Will EPA's Good Neighbor Plan increase costs to operate Tolk?

A Yes. Under the Good Neighbor Plan, Texas will have an initial electric generating units NO_X emission budget of 40,134 tons in 2023. By 2026, electric generating units would be required to reduce emissions to a level commensurate with SCR technology or purchase credits to offset emissions. In 2027, Texas's total NO_X budget drops to 23,009 tons, a reduction of nearly 50 percent.[47] Because the Tolk units lack modern pollution controls for NO_X (SCR), SPS has three options to comply with the rule: install SCR, buy pollution allowances, or retire the plant. As

[47] *See* U.S. EPA, State Budgets Under the Good Neighbor Plan for the 2015 Ozone NAAQS*, available at* https://www.epa.gov/csapr/state-budgets-under-good-neighbor-plan-2015-ozone-naaqs; *see also* U.S. EPA, *EPA's "Good Neighbor" Plan Cuts Ozone Pollution – Overview Fact Sheet*, *available at* https://www.epa.gov/system/files/documents/2023-03/Final%20Good%20Neighbor%20Rule%20Fact%20Sheet_0.pdf.

I explain here, moving up the retirement date of Tolk may be the best option for customers.

Q Is installing SCR at Tolk to comply with the Good Neighbor Plan likely to be cost-effective?

A No. Because SPS intends to retire Tolk by 2028, installing a major capital project in 2026 to comply with the Good Neighbor Plan would very likely not be cost-effective given the short period over which the investments would be amortized. Because SPS has not provided an estimate, I calculated an estimate of SCR capital costs for this plant. Using assumptions from EIA, the capital costs of SCRs would be approximately $145 million per unit at Tolk (or $290 million for the plant).[48] That is more than the net plant balance at Tolk today. These capital cost estimates do not include the rate of return on an SCR investment that SPS would receive if the costs are allowed in rate base, nor do they include annual operating costs; therefore, these estimates may understate the cost of installing SCR systems at Tolk.

Q What is the likely cost to SPS of complying with the Good Neighbor Rule at Tolk with NOx Allowances?

A Assuming that SPS does not advance the retirement of Tolk, SPS's other option to comply with the Good Neighbor Rule is to purchase NO_X allowances. These purchases will likely be expensive. EPA has provided an allocation for Tolk's

[48] U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2022: Electricity Market Module,* Table 8, Pg. 23, *available at* https://www.eia.gov/outlooks/aeo/assumptions/pdf/electricity.pdf.

emissions for ozone season 2025 that is far below each unit's emissions in 2021. The cost of NO_X allowances in future years is not known; but for illustrative purposes, I calculated the cost of compliance assuming that NO_X allowances cost $48,000/short ton, the highest trade price from 2022's ozone season.[49] This is a reasonable assumption because the Good Neighbor Rule is designed to significantly restrict the ability of polluters to emit NO_X, compared to current requirements, and thus will increase demand for a limited supply of allowances.

Q How much do you project it will cost SPS to purchase the required NO_X emissions for Tolk to operate with reduced operations under the Current Tolk Optimization Plan and with full year-round operations under the Modified Tolk Optimization Plan?

A As shown in Table 12 below, with reduced operations under the Modified Tolk Optimization Plan, I found that Tolk would exceed its 2025 NO_X allocation by 624 tons, resulting in compliance costs of $30 million. Under the Current Tolk Optimization Plan, Tolk would not exceed its NO_X emission limit in 2025. By 2027, Texas's statewide NO_X allowance will be reduced by 40 percent relative to 2025, increasing its compliance costs. Assuming Tolk's 2025 NO_X allocation is reduced proportionally to Texas's allocation in future years, SPS could pay as much as $125 million more in compliance costs under the Modified Tolk Optimization Plan than under Current Tolk Optimization Plan over the time period 2025–2028. Those excess costs are avoidable if SPS dispatches Tolk economically, and with the full cost of NOx emissions credits incorporated into its market bids, because this will drive down generation from the plant during

[49] Michael Ball*, Viewpoint: NOx could rise on new regulations*, Argus Media, (December 29, 2022), *available at* https://www.argusmedia.com/en/news/2405066-viewpoint-nox-could-rise-on-new-regulations?backToResults=true.

ozone season. The cost of compliance is likely to increase as Texas-wide emissions are ratcheted down through 2029. If SPS keeps Tolk online beyond 2028, it is likely to incur increasing emission costs to comply with the Good Neighbor Rule. These costs would be avoided with a 2028 retirement.

Table 12: Tolk's NO_x emission allowances, shortfalls, and costs under the Good Neighbor rule

	2025	2026	2027	2028	Total
NOx allocation *(short tons)*	1,004	811	599	563	
Current Tolk Optimization Plan					
Projected annual ozone season NOx emissions *(short tons)*	977				
Allowance shortfall *(short tons)*	(27)	166	378	414	
Compliance cost *($Millions)*	$(1.29)	$7.98	$18.13	$19.86	$44.68
Modified Tolk Optimization Plan					
Projected annual ozone season NOx emissions *(short tons)*	1,628				
Allowance shortfall *(short tons)*	624	818	1,029	1,065	
Compliance cost *($Millions)*	$29.97	$39.25	$49.40	$51.13	$169.75
Compliance cost delta between *plans ($Million)*	$31.27	$31.27	$31.27	$31.27	$125.07

** Assuming 2,400 GWh target for the Current Tolk Optimization Plan and 4,000 GWh target for the Modified Tolk Optimization Plan, and that 56% of generation occurs during ozone season under both scenarios.*
Source: EPA's Clean Air Markets Program Data; EPA's Final Good Neighbor Plan for the 2015 Ozone NAAQS.

Q Why do you project that SPS will spend substantially more on emission credits under the Modified Tolk Optimization Plan than under the Current Tolk Optimization Plan if the NO_X emission limits are only for the ozone season which happens during the summer, when we expect to see high generation at Tolk under both scenarios?

A If SPS were operating Tolk only during the summer under the Current Tolk Optimization Plan, we would expect to see 100 percent of its 2,400 GWh of generation occur during the summer months and zero percent occur in non-summer months. The summer months coincide with ozone season. Under the Modified Tolk Optimization Plan it would be easy to assume that SPS would generate the same 2,400 GWh in the summer season, and that the other 1,600 GWh during the non-ozone season. But based on SPS's historical data from the past five years, during which it was claiming to operating in conservation mode under the Current Tolk Optimization Plan, SPS was generating a substantial amount of energy outside the ozone season. In other words, while the Company did reduce generation levels overall over the entire year to conserve water, it did not cease operation in the non-peak season. For our calculations, we assumed SPS was likely to continue this practice in the future.

Q What assumptions did you make to calculate the estimated cost and emissions you present above?

A Using the past five years of historical data from EPA's Clean Air Markets Program Data ("CAMD"), I calculated the average percentage of generation that occurs at Tolk during ozone season. I found that 55.7 percent of Tolk's generation occurs during the ozone season, and the other 44.3 percent occurs during the non-peak months. I therefore assumed that under both scenarios, 55.7 percent of the annual generation would occur during the ozone season. This means I assumed a higher level of generation from Tolk during the ozone season under the Modified Tolk Optimization Plan than under the Current Tolk Optimization Plan.

I then calculated Tolk's average NO_X emissions rate, also from the CAMD data. I combined the estimated generation with the NO_X emissions rate to calculate the projected annual ozone season NO_X emissions that would occur under both the Modified Tolk Optimization Plan and the Current Tolk Optimization Plan. Then for each year from 2025 through 2028 I calculated the projected unit level emission allocations by applying the annual state-wide Good Neighbor emission reduction requirements to the 2025 unit allocations. To calculate the amount by which SPS is expected to exceed its allowance level in each year, I found the difference between the projected and yearly allocations and the projected annual emissions. I then applied the estimated compliance cost of $48,000/short ton to the expected NO_X emissions exceedance level to find the total expected compliance cost for each year.

Q Could other environmental regulations increase costs to operate Tolk in the next decade?

A Yes. While EPA has not yet acted on the State of Texas's plan to address visibility pollution, EPA has indicated that it will propose a federal plan for the first Regional Haze planning period addressing sulfur dioxide ("SO_2") pollution from so-called reasonable progress sources, which includes Tolk, by the end of July 2023.[50] EPA has a separate obligation to address Texas's visibility plan for the second planning period. In either case, a federal haze plan could require

[50] Decl. of David Garcia, *Texas v. EPA*, Case No. 16-60118, (5th Cir. Mar. 29, 2023).

reductions of NO_X and SO_2 at Tolk, which would increase the cost of operation. Similarly, EPA's proposals to address PM could also increase costs for Tolk.

iv. <u>SPS can retire Tolk early and manage ratepayer impacts.</u>

Q Will there be rate impacts with the early retirement of the Tolk generating assets?

A There may be. If the depreciation schedule for Tolk is moved up to match SPS's proposed retirement date, there will be less time to pay off the remaining plant balance and rates could increase in the near term.

Q Are there ways to mitigate the impact of early retirement on ratepayers?

A Yes, there are alternative financing and cost recovery mechanisms that SPS can use to minimize the cost impacts to ratepayers from the early retirement of Tolk. These include staggering the depreciation date from the retirement date, turning the remaining plant balance into a regulatory asset with a full or limited rate of return, disallowing some or all of the entire remaining balance, or taking advantage of newly-available financing mechanisms under the Inflation Reduction Act, which function much like traditional ratepayer-backed securitization.

Q Explain the benefits and downsides of staggering the depreciation date from the unit retirement date.

A Staggering the depreciation date from the retirement date can reduce ratepayer impact by spreading the remaining book value over a longer period. It reduces ratepayers' costs (and minimizes rate shock) in the near term. In exchange, ratepayers continue paying for an obsolete asset (while also paying for a new asset that can provide the energy and capacity they need). This can shift the cost burden away from people who received value from the asset in the past onto current and future ratepayers, who may or may not have ever benefited from the asset for which they are now being asked to pay.

Q Explain the benefits and downsides of putting the remaining plant balance into a regulatory asset.

A A regulatory asset is a generic asset that takes the remaining book value of a plant when it retires and allows the utility to continue recovering the costs it incurred in the past. With a regulatory asset the utility return can be set at a different rate than with the original asset. For example, the utility may be allowed to recover its original investment and its cost of debt but not to collect a rate of return for stakeholders. In this way, the utility is still able to pay off its debts, but its ability to profit on a retired asset can be limited. When the Dolet Hill power plant closed in 2021, the Texas Commission allowed Southwestern Electric Power Company ("SWEPCO") to put the remaining undepreciated balance into a regulatory asset to be amortized without a return.[51] This way SWEPCO was allowed to recover the capital it invested in the plant but could not continue to profit off of a retired asset. This is less extreme than a full disallowance, whereby the utility is not allowed to recover some or all of the remaining capital it invested. Where utility imprudence is clear and proven, disallowance may be appropriate; but it will impact the utility's credit score and its ability to pay off its debt, and it may make future projects more expensive.

[51] Order, Public Utility Commission of Texas, PUC Docket No. 51415, Pg. 12.

Q **Explain ratepayer-backed securitization.**

A In instances where utility costs are almost certain to be passed on to ratepayers, ratepayer-backed securitization can provide benefits for both the utility and the ratepayers. Securitization allows the company to recover its original investment, gives the utility capital in hand that it can invest in new resources, and reduces the rate impact for customers by reducing the rate of return collected on the investment.

Securitization is a refinancing mechanism through which bonds are issued to raise funds to refinance a plant's undepreciated balance. The bonds are paid back over time by customers through a dedicated surcharge on their bills which goes to the debt investors rather than to the utility. The customer bond repayment is irrevocable and non-bypassable[52] and therefore repayment to the lender is guaranteed. This guarantee or "securitization" of repayment means that the bond can be issued at a lower interest rate compared to typical utility interest rates.[53] Additionally, many major credit rating agencies exclude securitization debt in their assessment of debt-to-equity ratio for utility credit scoring. This exclusion allows utilities to refinance the remaining net book value through 100-percent securitization, rather than the typical combination of debt-to-equity financing.[54] The lower interest rate, combined with 100-percent securitization financing, means that customers ultimately pay a lower overall cost compared to paying the

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[52] North Carolina Energy Regulatory Process, *Securitization for Generation Asset Retirement: Study Group Work Product,* (Dec. 18, 2020), *available at* https://files.nc.gov/ncdeq/climate-change/clean-energy-plan/Securitization-Products-Final.pdf.

[53] *Id.*

[54] *Id.*

utility directly. The utility also benefits by recovering the remaining undepreciated value of the plant.

Q How is bond securitization implemented?

A Regulators create a special purpose entity, which issues the bonds on behalf of the ratepayers.[55] The entity also owns the future ratepayers' charges and repays the bond using the charges collected through ratepayer bills. The entity must be separate and isolated from the utility such that the charges dedicated to the bond are not available to the utility or its creditors in the event of financial hardship.[56] Once the obligations to the bondholders are met, the surcharge is removed from customers' bills.

Q What are the benefits of securitization for the utilities and for ratepayers?

A Through securitization, the utility collects the full outstanding value of the plant, but its return on capital is limited. The capital released through securitization can be re-invested in other capital projects, which has the potential to increase total utility earnings.[57] This is especially true if the utility invests in clean energy, which is typically more capital intensive to build than fossil plants (on a per-kWh-generated basis)[58] but has minimal fuel and operational costs. If the plant's remaining net book value is released through securitization, and re-invested in

[55] Uday Varadarajan, David Posner and Jeremy Fisher, *Harnessing Financial Tools to Transform the Electric Sector,* Sierra Club, (Nov. 2018).

[56] *Id.*

[57] North Carolina Energy Regulatory Process, *Securitization for Generation Asset Retirement: Study Group Work Product,* (Dec. 18, 2020), *available at* https://files.nc.gov/ncdeq/climate-change/clean-energy-plan/Securitization-Products-Final.pdf.

[58] Uday Varadarajan, David Posner and Jeremy Fisher, *Harnessing Financial Tools to Transform the Electric Sector,* Sierra Club, (Nov. 2018).

other capital projects, shareholders can see profits grow, while ratepayers benefit from new, lower cost resources.

Q Is there enabling legislation in Texas for securitization?

A No, not yet. There is enabling legislation in New Mexico; but as Tolk is located in Texas, it does not currently apply. Enabling legislation is required for securitization to ensure that bond repayment is irrevocable and non-bypassable and to allow for the creation of the special purpose entity.[59]

Q Has securitization been adopted in other jurisdictions?

A Yes. Securitization is not new. Securitization of stranded assets—particularly, coal-related assets—is quickly becoming an industry norm. In the 1990s during utility restructuring, utilities selling generation assets could not always recoup their capital expenses when the book value of the plants turned out to be higher than their market value. As a result, states and Commissions allowed for bond securitization to compensate utilities for their stranded assets.[60] Since then, it has been used widely as a tool to enable early retirements or finance pollution control upgrades, including in the following places:

1. Duke Energy Florida used securitization to finance $1.3 billion for the closed Crystal River nuclear plant. The bond interest rate of 2.72 percent

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[59] *Id.*

[60] *Id.*

was much lower than Duke Energy's cost of capital, avoiding $700 million in customer costs over 20 years.[61]

2. The New Mexico Public Regulation Commission approved the use of securitization to collect $361 million to recover costs associated with the closure of San Juan Generating Station.[62] Bond funds will be used to recover the net book value of the plant, pay for decommissioning, and provide $40 million for the economic development of the area, including assistance for laid off coal plant workers.[63]
3. In 2007, Allegheny Power used securitization bonds to finance $450 million in environmental controls, saving $130 million for ratepayers.[64]

Q Are there other options for securitization if enabling legislation is not passed in Texas?

A Yes. In the recently passed IRA, the U.S. Department of Energy's Loan Program Office provides $5 billion in funding to facilitate $250 billion in low-cost loans.[65] These government-backed loans act in the same way as ratepayer-backed bond securitization. Through this provision, the program requires reinvestment of the

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[61] *Id.*

[62] Kevin Robinson-Avila, *PNM gets OK to abandon San Juan,* Albuquerque Journal, (Apr. 1, 2020), *available at* https://www.abqjournal.com/1439120/prc-approves-san-juan-abandonment.html.

[63] *Id.*

[64] Saber Partners, LLC, *State of West Virginia, Public Service Commission, available at* https://saberpartners.com/engagements/state-of-west-virginia-public-service-commission/.

[65] Inflation Reduction Act, Pub L. No. 117-169, 50141, 50144 (Aug. 16, 2022), *available at* https://www.congress.gov/bill/117th-congress/house-bill/5376/text.

released capital. Specifically, the utilities will need to "retool, repower, repurpose, or replace" retiring assets.[66] Funding through this program expires in 2026.

Q What do you recommend for minimizing ratepayer impacts of an early Tolk retirement?

A The Commission should order the Company to evaluate the economics of using the securitization tools available under the Inflation Reduction Act to refinance the remaining balance. This would minimize rate shock to customers while still allowing SPS to recover the capital it invested in Tolk. The Commission should also limit SPS's capital spending at Tolk by indicating that it is unlikely to allow SPS to recover investments at Tolk above a certain level without pre-approval. This will minimize the book value that has to be recovered from ratepayers over the plant's remaining life (or beyond, based on how the plant net balance is recovered).

5. SPS SHOULD WORK TO PROCURE MORE CLEAN ENERGY RESOURCES ON A ROLLING BASIS TO MEET FIRM CAPACITY NEEDS AND REDUCE CUSTOMER COSTS AND RISKS.

i. SPS's current resource procurement efforts

Q Provide an overview of SPS's recent procurement efforts.

A As discussed above, SPS brought online several wind projects in the past few years. The Company recently issued an RFP to procure resources to meet its load requirements, mainly stemming from SPP's updated reserve margin and capacity

[66] *Id*. § 1706.

accreditation framework, and to allow the retirement of some of its aging gas steam plants.

Q What types of resources are other regional entities developing to meet their projected future needs?

A Arizona Southwest Public Power Agency ("SPPA") recently entered into a joint venture with BrightNight to have 300 MW of solar energy capacity and 600 MWh of battery energy storage delivered. SPPA expects the project will meet around a third of its peak capacity needs and roughly 20 percent of its energy needs. The power will come from Box Canyon solar project in Pinal County and is expected to be operational in 2025.[67] SPPA selected this project after issuing an RFP for up to 200 MW of gas-fired generation and 100 MW of solar PV. SPPA chose the clean energy project because the scope of technology surpassed its requirements as outlined in its RFP.[68]

In New Mexico, El Paso Electric ("EPE") is currently building or seeking approval for 390 MW of solar PV and 115 MW of battery storage across three different projects. Specifically, EPE is building a 120 MW solar PV and 50 MW storage project at Buena Vista, and a 140 MW solar PV project at Hecate. EPE is also requesting approval to build a 130 MW solar PV and 65 MW battery storage

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[67] Ryan Kennedy, *BrightNight to meet one third of Arizona utility's peak demand with solar and storage project*, PV magazine, (July 19. 2022) *available at* https://pv-magazine-usa.com/2022/07/19/brightnight-to-meet-one-third-of-arizona-utilitys-peak-demand-with-solar-and-storage-project/.

[68] Andy Colthorpe, *Arizona utility groups sign PPA for 300 MW/600 MWh solar-plus-storage power plant,* Energy Storage News, (July 20, 2022), *available at* https://www.energy-storage.news/arizona-utility-groups-sign-ppa-for-300mw-600mwh-solar-plus-storage-power-plant/.

project at Carne. PNM is also building and purchasing 850 MW of solar PV and 570 MW of battery storage across four different projects (Arroyo, San Juan, Jicarilla, and Atrisco) to replace the retiring San Juan Generating Station.[69]

ii. SPS should be more proactive in procuring replacement resources rather than waiting for an urgent capacity need.

Q What are SPS's current and projected capacity and energy needs?

A SPS projects it will have a capacity need starting in the summer of 2026,[70] and as early as the summer of 2024 if additional new load materializes.[71] Specifically, SPS projects that with the updated SPP reserve margin and capacity accreditation, and load growth, it will need 106 MW of capacity in 2026 and 367 MW of capacity in 2027.[72]

Q What type of replacement resources should SPS be considering?

A SPS should be evaluating portfolios of resources that include solar PV, onshore wind, battery storage, demand-side management, transmission build-out, and market purchases.

With the recent passage of the IRA, tax credits available for renewables and battery storage are stabilizing prices in the near term and are expected to drive down prices in the near future. SPS's region of Texas and New Mexico has excellent solar PV potential, which now qualifies for the PTC or ITC. Standalone

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[69] Case No. 19-00195-UT and Case No. 20-00182-UT.

[70] Direct Testimony of Ben Elsey, Pg. 25.

[71] *Id.*, Pg. 26.

[72] *Id.*, Table BRE-RR-3, Pg. 25.

battery storage, which did not previously qualify for a tax credit, now qualifies for the ITC. Additionally, as discussed above, the IRA added new ITC and PTC tiers that entitle any solar, wind, or battery storage projects to a 10 percent adder if the projects are located in an energy community or in many brownfield sites. The preference to delay deployment while technology costs fall should be less of an issue now, with the ITC offsetting a substantial portion of the project cost.

Additionally, the *Infrastructure Investment and Jobs Act*, as well as the IRA, provided funding for transmission projects.[73] SPS could use this funding to access high quality wind resources, as well as to modernize and expand its transmission network to better integrate renewables.

Q How should SPS be thinking about resource procurement?

A Currently, SPS procures new resources only when it identifies a capacity need during its IRP process. While utilizing existing resources is not inherently wrong, this model tends to favor the status quo. It keeps existing resources online and keeps the costs to operate and maintain these resources in rate-base, even if there are lower-cost, feasible options. This model tends to understate the risk and cost of continuing to rely on existing resources, overstate the cost and risk of alternatives, and delay progress and action until something breaks or becomes so costly that it is impossible to ignore. Under this model, excess costs incurred when a plant breaks down or fuel prices spike are explained away as an anomaly, and something the utility never could have predicted.

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[73] U.S. Department of Energy, *Biden-Harris Administration Announces $13 Billion to Modernize and Expand America's Power Grid*, (Nov. 18, 2022), *available at* https://www.energy.gov/articles/biden-harris-administration-announces-13-billion-modernize-and-expand-americas-power-grid.

Yet these costs are somewhat predictable. Market and gas price spikes are becoming more frequent, and plant outages become more likely and frequent as a plant ages. Utilities can mitigate the costs and risks associated with these factors with a rolling resource procurement model. For many of the reasons discussed in the section above, procuring new resources on a continuous basis can be more cost-effective and lower risk than relying on existing resources. Doing so also introduces flexibility into the resource planning process.

Q Won't a rolling procurement model just lead to over-procurement of capacity and produce an overbuilt system that is costlier for SPS ratepayers?

A No, not necessarily. My recommendation is not that SPS should overbuild by procuring thousands of MW more than it needs. But if an existing resource is facing forces that, while uncertain, are all likely to lead to higher costs and higher risks, and new low-cost, clean energy resources are available but require lead time to come online, there is little downside to planning actively and proactively.

With renewables and battery storage, the costs of early deployment are minimal relative to the risks the resources help avoid and the value that they provide. Renewables and energy storage require no fuel and have limited and known variable operating costs, meaning that they are insulated from the risk of fuel price and market price volatility that can impact fossil resources. The only real costs are the revenue requirement impacts of building a resource a year or two in advance of when it is "needed" and at a cost that might be lower in a year or two. In the time it takes to bring the new resources online, it is likely that conditions will change such that the new resource either will be needed by the utility, will outcompete existing resources, or at the very least, will be valuable to other regional entities that are not as proactive.

Q Doesn't this approach of procuring before the utility has a capacity need conflict with industry best practices for resource procurement?

A No. A more flexible procurement approach represents a necessary evolution in the planning process as the penetration of renewables on the grid increases, as fossil fuel prices become more volatile, as interconnection queue issues risk delays, and as project development is shifted from a few centralized utilities and a few centralized energy resources to many small parties and resources.

In fact, other utility commissions and utilities are starting to adopt this resource planning approach. For example, the Public Service Commission of Missouri stated in its April 2023 order approving Ameren Missouri's request for a Certificate of Convenience and Necessity for the Boomtown Solar Facility that "Waiting to add renewable generation resources until coal-fired plants are retired and capacity need is immediate would put Ameren Missouri at risk of being unable to meet its customers' load at peak times."[74]

Ameren had argued in its application that "…a gradual, sustained transition to renewable energy is more cost effective and practical than waiting until there is an actual capacity need and ensures the Company can continue to deliver sufficient quantities of reliable, affordable energy to customers…"[75]

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[74] Missouri Public Service Commission, File No. EA-2022-0245, Report and Order (Apr. 12, 2023), Pg. 29.

[75] Missouri Public Service Commission, File No. EA-2022-0245, Direct Testimony of Ajay Akora, Pg. 7.

Q Why is this model better suited for the current clean energy transition?

A Transitioning to clean energy resources now rather than waiting until there is an immediate need provides more flexibility to retire aging units as needed and protects ratepayers from reliance on the market or volatile fossil-fueled resources, from coal supply disruptions, and from project delays or unit breakdowns.

The costs to maintain existing resources are high, and units can break down unexpectedly. Coal supplies can also be interrupted, as discussed above, causing plants to de-rate their capacity when their coal supplies were limited. When this happens, the full capacity of each resource is not available.

As another example, CenterPoint Indiana is facing unexpectedly high fuel and market energy and capacity costs because one of its coal plants, Culley Unit 3, broke down and the Company has no replacement resources available. The part that CenterPoint needs to repair Culley 3 is no longer made by the original manufacturer, so CenterPoint had to purchase the part from a retired coal plant in Montana. This process required CenterPoint to put Culley 3 into outage for a year and to purchase high-cost power in the interim.[76]

Additionally, all projects, especially renewable projects, may be delayed by a year or two with supply chain challenges. I have seen this around the country. PNM, for example, delayed the retirement of San Juan Generating Station three months to meet summer 2022 peak needs[77] because the renewables PNM needed to

[76] Brady Williams, *Broken coal plant leads CenterPoint Energy to petition for rate increase*, 14 News, (Nov. 22, 2022), *available at* https://www.14news.com/2022/11/22/broken-coal-plant-leads-centerpoint-energy-petition-rate-increase/.

[77] Notice of Public Service Company of New Mexico and Request for any Necessary Modification to or Variance from Abandonment Date of San Juan Generating Station Unit 4, Case No. 19-00018-UT, (Feb.17, 2022).

replace the unit were delayed coming online. As discussed above, EPE announced that the commercial operation dates for the Buena Vista and Hecate solar projects were delayed by one and two years respectively based on supply chain challenges and the Department of Commerce solar tariff.

Additionally, some renewable projects may require transmission build-out or investment, which cannot happen overnight. But with transmission funding available through the IRA, and other transmission reforms underway around the country, the pace of transmission expansion should pick up.[78] These reforms should remove barriers to transmission development and help socialize the costs across a larger group of ratepayers who will reap the benefits from the development, rather than just requiring that the next project coming online bears the full transmission cost.

Planning a project around a specific deadline in the current environment is a risky strategy. That does not mean that SPS should not rely on renewables; rather, it means that shifting to a model where resources are deployed as they become available will make it more likely that resources will be online by the time SPS needs them.

Q Does this conclude your testimony?

A Yes.

[78] *See, e.g.*, Congressional Research Service, *Electricity Transmission Provisions in the Inflation Reduction Act of 2022,* (Updated Aug. 23, 2022), *available at* https://crsreports.congress.gov/product/pdf/IN/IN11981#:~:text=Inflation%20Reduction%20Act%20of%202022,-Updated%20August%2023&text=On%20August%2016%2C%202022%2C%20President,infrastructure%20in%20the%20United%20States.