BEFORE THE COURT OF ADMINISTRATIVE HEARINGS

FOR THE

MINNESOTA PUBLIC UTILITIES COMMISSION

STATE OF MINNESOTA

In the Matter of the Petition of the City of Slayton for the Determination of Compensation for City Acquisition of Xcel Energy Electric Service Territory	MPUC Docket No. E-002, PT-7157/ SA-25-129 CAH Docket No. 25-2500-40870

REBUTTAL TESTIMONY OF DAVID BERG
ON BEHALF OF THE CITY OF SLAYTON

January 9, 2025

Exhibit ___

PUBLIC DOCUMENT

I. INTRODUCTION

Q. What is the subject of your rebuttal testimony in this case?

A. The primary focus of my rebuttal testimony is to respond to certain aspects of direct testimony provided by Xcel Energy witnesses Lisa Peterson, Bixuan Sun and Allen Krug.

Direct Testimony of Lisa Peterson

Q. The direct testimony of Lisa Peterson includes Xcel's view of just compensation to be paid by Slayton for this proposed acquisition. What areas of that just compensation will you address?

A. Table 4 on page 46 of Ms. Peterson's direct testimony summarizes her recommendation for just compensation. A copy of that table is shown below.

Table 4
Just Compensation

Value of Property	$3,220,653
Loss of Revenue*	$40,133,871
Meter Integration Expense	Est. $140,000
Continued Service Integration Expense	Est. $15,000
DER Integration Expense	To Be Identified
Stranded Slayton West Substation	$1,131,3540,430
Total	**$44,640,878**

* Or $3,645,618 per year over 2026-2045

I will be commenting on each item contained in her summary of just compensation shown above.

Q. Lisa Peterson's direct testimony includes $3,220,653 for the value of property. Do you agree with that figure?

A. That figure matches the amount I included in my direct testimony. Ms. Peterson and I relied on the same information provided by Xcel in this matter.

Q. Do you have any other comments regarding value of property as it pertains to Ms. Peterson's direct testimony?

A. Yes, in her direct testimony on page 11, lines 6-17 she states:

> *"Second, this amount reflects the value of property at a specific point in time. If Slayton decides to move forward with its proposal to purchase Xcel Energy's property, it will likely not take place for some time. The final value of property will need to be updated to reflect additional depreciation for the equipment currently installed, and the possibility that new equipment will be needed to continue to provide safe and reliable service to Slayton customers while the purchase is pending.*
>
> *Q. HOW DO YOU PROPOSE TO UPDATE THE VALUE OF PROPERTY?*
> *A. I propose that the Commission approve the methodology I have used to calculate the value of property, and that the current estimate is $3,220,653. The final cost will be calculated at the time of transfer based on this methodology."*

I concur with her testimony that the final number should be adjusted for changes in the value on an original cost less depreciation to reflect additional depreciation and the potential addition of any new facilities. The City of Slayton would certainly want to review and comment on the final number and the basis for adjustments to the current estimate.

Q. Lisa Peterson's direct testimony includes a lump sum figure of $40,133,871 for the loss of revenue portion of just compensation, do you agree with this figure for loss of revenue?

A. I do not agree with this amount. My direct testimony in this matter summarizes my view of appropriate loss of revenue to be paid by Slayton to Xcel. Ms. Peterson and I have very different views of appropriate loss of revenue.

Q. In her Table 4 shown above, she proposes a lump sum payment for loss of revenue. Do you agree with this method of payment for loss of revenue?

A. No, I do not. In the vast majority of cases for compensation in similar matters, the Minnesota Public Utilities Commission (MPUC or Commission) has opted for a per kwh payment over a period of time generally referred to as a mill rate (one mill is one-tenth of a cent per kWh). Based on my participation in many of those cases, I was aware that the Commission moved away from lump-sum payments to per kWh mill rates due to the uncertainty of sales over a projected period of time. A lump-sum payment would require making assumptions regarding load growth (or lack thereof) over a projected time period. The Commission determined that a payment based on actual sales would be a more reasonable and fair approach. In her direct testimony, Ms. Peterson makes the exact opposite argument. On page 29 of her direct testimony, lines 15-18, she states:

> *"Payments based on volumetric rates are subject to uncertainty regarding the amount of consumption. If consumption in Slayton is higher or lower than expected, the actual amount of lost revenues recovered could be higher or lower than ordered by the Commission."*

The fact that payments would be higher or lower based on consumption is precisely the reason the Commission opted for per kWh mill rates. The Commission has determined compensation in this manner in six of the seven contested cases under Minn. Stat. 216B.44 and has not evaluated the loss of revenue based on a lump sum payment since the Olivia case, Docket No. SA-85-93. As I stated in my direct testimony, page 15, lines 4-11, the Commission, in City of Rochester, No. SA-93-498, determined that a per kWh rate based on actual sales during the compensation period provides a more accurate payment. The Commission has been consistent in that approach in litigated cases since the referenced Rochester case in 1995.

Q. Does Ms. Peterson suggest an appropriate per kWh mill rate in her analysis?

A. Not directly, but a per kWh mill rate can be calculated from her recommended results.

Q. Have you made this calculation?

A. Yes, I have. In the footnote included with her Table 4 presented above, she suggests that her lump sum loss of revenue payment could be paid over time with a flat annual payment of $3,645,618. On page 43 of her direct testimony, line 16, she states that annual consumption in Slayton is 20,501,184 kWh. If you divide her $3,645,618 annual payment by 20,501,185 kWh the result is $0.1778 per kWh (177.8 mills/kWh). A flat mill rate based on actual sales during the loss of revenue period would be consistent with most recent Commission decisions. Ms. Peterson does not appear to agree with that option for payment of loss of revenue. Moreover, predicting sales for the 10 years used in the cooperatives compensation cases, and an additional 10 years as proposed by Xcel, creates the potential for significantly inaccurate lost revenue payments based on a present valued lump sum.

Q. How does this mill rate compare to the revenue Xcel receives from Slayton customers?

A. In Ms. Peterson's direct testimony, Exhibit___(LRP-1), Schedule 3, page 1 of 6, she states that the annual 2025 revenue from Slayton customers was $2,914,221. If you divide this total revenue by 20,501,185 kWh of annual sales the result is an average revenue of $0.1421 per kWh (142.1 mills/kWh). Based on values contained in Ms. Peterson's direct testimony, Xcel's net loss of revenue is 125% (177.8 mills divided by 142.1 mills) of the total revenue received from Slayton customers.

Q. Based on your experience in these matters, does this result make sense?

A. No, in my opinion there is no logical scenario where the net loss of revenue could be more than the total revenue received. This would require that all assets and costs associated with serving the customers in Slayton be stranded and there would have to actually be additional expenses associated with not serving these customers.

Q. In calculating her lump sum loss of revenue amount, Ms. Peterson included projected annual growth in sales for Slayton. Was this appropriate?

A. No, it was not. On page 19 of her direct testimony she presents Table 2 shown below.

Table 2
Growth Rates

	Residential	Non-Demand /Demand	Lighting
Use Per Customer	2.4%	0.1%	0.0%
Customer Count	0.7%	0.4%	0.8%

This table shows the annual growth rates she utilized for use per customer and customer counts in her loss of revenue analysis. Growth in both use per customer and customer count compounds on each other, the effective annual growth in Residential sales would be 3.1% (1.024 use per customer times 1.007 customer count growth). She states on lines 6-8 on page 19 of her direct testimony that:

> *"These assumptions are based on Xcel Energy's most recent sales forecast, which was filed in our pending rate case with the Rebuttal Testimony of Company witness Benjamin S. Levine."*

Q. Why are these growth assumptions not appropriate for this specific case?

A. The growth assumptions in her testimony are Xcel's assumptions for growth in its entire Minnesota system as utilized in its most recent rate case. The loss of revenue in this case is specific to the situation in Slayton and this system-wide growth assumption is not appropriate for Slayton.

Q. Why are the system-wide growth assumptions not appropriate for Slayton?

A. Based on recent sales data for Slayton and discussions with Slayton city representatives, no increase in number of customers or per customer usage is anticipated in Slayton. Xcel's response to Slayton's Information Request Number 81 shows the total annual sales in Slayton for the period 2015-2024.[1] As shown, the total sales in 2024 were actually 5.4% lower than the total sales in 2015. There is no evidence supporting the assumption that sales in Slayton will increase annually into the future.

Q. Is there additional evidence that system wide (state of Minnesota) projections are not appropriate for projections in the Slayton area?

A. Yes, Attachments G, H, and I to this rebuttal testimony are information from the U.S. Census Bureau. Attachment G is a 2020 Census Minnesota Profile summarizing statewide population information for the entire state.[2] It shows that the state population grew from 5,303,925 in 2010 to 5,706,494 in 2020. The represents an increase of 7.6%. Attachment H is a U.S. Census QuickFacts publication for Murray County, Minnesota.[3] Slayton is located in Murray County. It shows that from 2010 to 2020, the population of Murray County decreased from 8,725 to 8,179 (a decrease of 6.3%). Additionally, it estimated that the Murray County population continued to decrease to an estimated

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[1] Xcel Electric Response to City of Slayton IR No. 81.
[2] Attachment G: Census Data for State of Minnesota 2020.
[3] Attachment H: Census Data for Murray County Minnesota 2020

8,044 by 2024. The population in the City of Slayton has generally followed this same downward trend. In 2010, the population of Slayton was 2153.[4] In 2020, the population was 2013.[5] This represents a decline of approximately 6.5%. Based on U.S. Census data showing declining population projections, for customer counts in Slayton should ***decrease*** rather than increase. I add that in my direct testimony I showed that Slayton has a higher than average cost to serve and a decrease in customers due to population loss would exacerbate this situation.[6]

Q. Do you have any comments relative to the specific components contained in Ms. Peterson's loss of revenue calculation?

A. Yes, in her direct testimony she breaks the Xcel revenue requirement into five distinct categories and analyzes how much of each cost category would be avoided by not serving the customers in Slayton. Her five cost categories are listed in Table 3 on page 21 of her direct testimony as shown below.

[4] Slayton Response to Xcel IR No. 19 (City of Slayton Land Use Plan with Active Living Component (2016)), at Slayton 0000081 to 0000082.
[5] Attachment I: Census Data for Slayton City Minnesota, U.S. Census Bureau), also available at https://data.census.gov/profile/Slayton_city,_Minnesota?g=160XX00US2760808 (last visited Jan. 2, 2026)
[6] Berg Direct Testimony, pages 21-22 and 34-35.

Table 3
Cost Components

Cost Component
Fixed Production
Variable Production
Transmission
Distribution
Customer Costs

I will address each of these categories, including her conclusions regarding the amount of each category that can be saved (avoided) by not serving the customers in Slayton. It is important to view the results of Ms. Peterson's analysis in light of the Commission's statement (in rejecting the cooperative's argument for greater than 10 years of lost revenue payments) in the City of Rochester case (SA-93-498), that the utility "is expected" to "adjust to new service realities and to mitigate its damages for loss of these service rights as quickly and efficiently as possible." [7] If Xcel has an asset currently utilized to serve Slayton but is made available to serve elsewhere on its system, the adjustment has been made, and no loss of revenue is warranted. Also, if adjustments are necessary, Xcel, based on its size and ever- changing service requirements, has ample opportunities to quickly make adjustments in its operations to mitigate the loss of Slayton.

Q. How much of the fixed production cost component does Ms. Peterson state can be avoided by not serving Slayton?

A. She concludes that zero percent of fixed production costs are avoidable. On lines 13-19 on page 24 of her direct testimony she states:

> *"Generation units are long-term infrastructure projects, and once they are built, the costs of the projects must be recovered in rates. It is not possible to, for example, get rid of a small sliver of a nuclear plant because Slayton customers*

[7] *See also* Berg Direct Testimony, page 38.

> *leave the system. While we will adjust our future planning to account for the loss of Slayton customers, our existing power plants are already constructed and operating, and their costs cannot be avoided."*

Based on Ms. Peterson's logic, the generating assets associated with serving Slayton will be a stranded fixed cost forever. While she states above *that 'we will adjust our future planning to account for the loss of Slayton customers'*, her recommended loss of revenue component for fixed production indicates that Xcel won't or can't adjust. On pages 24-27 of my direct testimony, I address this issue based on previous Commission decisions, value of excess capacity in the MISO market, and Xcel's future capacity needs as outlined in its 2024 Integrated Resource Plan. In Ms. Peterson's quoted text above, she refers to "getting rid of a small sliver of a nuclear plant." This is an interesting example, but it does not represent the way power resources and the power grid operate. The interconnected grid, including Xcel and many more operating utilities, supplies all load to all customers through economic dispatch of all operating generating plants. No one plant is built to serve one group of customers. In my direct testimony I show Xcel's plans for adding new generating units. The 4 MW of capacity currently needed for Slayton can easily supplant 4 MW of the new generation planned by Xcel. To not adjust to its changing loads, whether that is an increase or decrease in load, would represent improper planning and operation on Xcel's part. If we acknowledge that future generating capacity units are often more expensive on a per unit basis than an existing generating unit, an argument could be made that freeing up 4 MW of existing capacity for near term future load growth could actually save Xcel even further costs relative to its fixed generation revenue requirement.

Q. How much of the variable production cost component does Ms. Peterson state can be avoided by not serving Slayton?

A. She states that only fuel costs are avoidable within the variable production cost component. She states, without providing relevant data for the calculation, that fuel makes up 36.4% of the lost revenue calculation. Specifically, in lines 10-18 on page 21 of her direct testimony, she says:

"Q. WHAT VARIABLE PRODUCTION COSTS ARE AVOIDABLE?

A. Variable production costs include fuel, purchased power, sales and economic development, administrative and general expenses, conservation improvement program expenses, amortizations, payroll taxes, non-plant related deferred income taxes, and other expenses. From this list, fuel expenses are avoidable. The Company will burn slightly less fuel after Slayton leaves the system, so fuel should be treated as an avoided cost. Fuel makes up approximately 36.4 percent of the variable production category, so the Company has treated 36.4 percent of the category as avoidable for the lost revenue calculation."

Q. If Ms. Peterson states that the fuel costs are avoidable, does she specifically state which variable production costs are not avoidable?

A. Yes, on line 20 of page 21 and lines 1-6 of page 22 in her direct testimony she states:

"Q. WHAT VARIABLE PRODUCTION COSTS ARE NOT AVOIDABLE?

A. The remaining costs are not avoidable. The Company does not expect any changes related to its purchased power costs, sales and economic development expense, administrative and general expenses, conservation improvement program expenses, amortizations, payroll taxes, non-plant related deferred income taxes, or other items in the variable category as a result of Slayton exiting the system. As a result, these costs are not avoidable."

Q. Do you have any comments relative to her statement above regarding her list of "not avoidable" variable production costs?

A. Yes, I have general observations and specific comments regarding her list of "not avoidable" variable production costs.

She mentions "purchased power costs" as not avoidable. When a utility purchases power from another entity, the costs are generally divided between demand costs (representative of fixed costs) and energy costs (representative of variable costs). Demand costs related to purchased power would be properly included in the fixed production cost component which I address above. If Xcel includes these costs in the variable projection component, which is allocated to customer classes based on energy use, it would be an improper cost classification with Xcel's filed cost-of-service analysis. Energy costs regarding purchased power are similar to fuel costs; if you buy less energy, you save money. Those costs will decrease with fewer purchases, which is proper reduction within the loss of revenue calculation.

She also lists "conservation improvement program expenses" as not avoidable. The State of Minnesota has conservation improvement expenditure requirements for utilities as listed in Minnesota Statutes, Section 216B.241 (Public Utilities; Energy Conservation and Optimization). Specifically, this statue includes the following:

> *Subd. 1c.* ***Public utility; energy-saving goals.***
>
> *(a) The commissioner shall establish energy-saving goals for energy conservation improvements and shall evaluate an energy conservation improvement program on how well it meets the goals set.*
>
> *(b) A public utility providing electric service has an annual energy-savings goal equivalent to 1.75 percent of gross annual retail energy sales unless modified by the commissioner under paragraph (c).*

As shown in the statutory language, public utilities (which includes Xcel) are required to spend 1.75 percent of gross annual retail energy sales on energy conservation improvements. To the extent the loss of Slayton customers would decrease Xcel's overall gross annual sales revenue as compared to Xcel's gross revenue with Slayton, Xcel's state requirements for energy conservation improvement expenditures would decrease.

Q. How do you view the remaining items listed under variable production costs by Ms. Peterson as 'not avoidable'?

A. Ms. Peterson's five cost categories as listed in her Table 3 above are slightly different than the 11 cost categories I included in my direct testimony as listed on page 17 of my direct testimony. I assume that her "variable production costs" are generally equivalent to the on-peak and off-peak requirements included in my direct testimony which I took directly from Mr. Barthol's cost-of-service model from Xcel's last rate case. On page 21 of his direct testimony in Docket No. E002/GR-24-320, Mr. Barthol states that he uses the "E8760 Allocator" for these items. The E8760 allocator is an energy allocator which allocates costs to classes based on energy use over the year. Utilization of an energy allocator specifically identifies these costs as energy related and should be treated as such within the loss of revenue calculation. An energy allocated cost should vary based on energy and would reduce with less energy sold.

Q. How much of the transmission cost component does Ms. Peterson state can be avoided by not serving Slayton?

A. She also concludes that zero percent of transmission costs are avoidable. On lines 5-8 on page 25 of her direct testimony she states:

> *"The Company constructs, owns, and operates transmission lines to deliver power from generation units to our customers, and to interconnect to the regional energy grid. These investments are critical to ensuring the reliability of both our grid and the regional grid."*

She adds in lines 13-16 on page 25:

> "*Once a transmission line is constructed, its costs are recovered from customers over decades. Slayton customers contribute to those costs, and there is no alternative source of that revenue once Slayton customers exit the system."*

Q. Do you agree with her statements listed above?

A. As a general statement regarding how transmission lines are planned for, built and operated, I agree with her statements. However, her statements are not relevant to a calculation of loss of revenue.

Q. What is relevant regarding transmission costs as they pertain to the loss of revenue calculation in this matter?

A. Mr. Mark Mitchell is also providing rebuttal testimony for Slayton regarding transmission' and explains how the MISO market works related to recovery of transmission costs. Based on his testimony and my own understanding of transmission ownership and cost recovery in MISO I conclude the following:

- The 69-kV transmission system around Slayton and owned by Xcel is included in the MISO transmission system.
- All transmission owners within MISO, including Xcel, get full recovery of transmission ownership and operating costs from MISO, whether they use the transmission to serve their own customers or not.
- Xcel will still get full recovery, via MISO, of its transmission revenue requirements for the Slayton area transmission system.
- Transmission costs paid by retail customers are based on load served. Xcel's transmission costs associated with serving Slayton will no longer be part of Xcel's retail revenue requirement following acquisition, so they are fully avoided.
- Slayton customers will continue to pay transmission costs to MISO (to help meet Xcel's transmission investment) through their new power supply arrangement.
- Including transmission costs in the loss of revenue payment would double charge Slayton customers for transmission: 1) through the new power supplier with transmission payments to MISO, and 2) to Xcel via the loss of revenue payment
- Including transmission costs in the loss of revenue payment would double pay Xcel for transmission: 1) as their normal payments from MISO continue, and 2) they receive payment from Slayton via loss of revenue payment.

Q. Did it surprise you that Xcel included transmission costs in its loss of revenue payments?

A. Yes, Xcel is very active in MISO and as a large and sophisticated investor owned utility, Xcel should be aware of how transmission cost recovery occurs within the MISO managed system.

Q. Did Ms. Peterson make any other statements regarding transmission that you would like to respond to?

A. Yes she did. As I quoted above, Ms. Peterson has testified that zero percent of the transmission costs are avoidable. She also states that Slayton customers contribute to those costs and there is no alternative source of that revenue when Slayton customers exit the system. Even though she does not use the term above, the circumstance she is describing could also be described as leaving a portion of the transmission system as a ”stranded cost”. A utility stranded cost is a financial burden created when a utility company is unable to recover its investments in infrastructure due to changing circumstances. I believe that Ms. Peterson’s portrayal regarding the transmission system fits that definition.

Q. Why is the stranded cost concept important?

A. Later in her testimony, on page 40, line 24 and page 41, lines 1-2 she states: *”In addition, the Company evaluated whether there would be stranded costs from the transmission system and concluded that there would not.”* Her statement regarding no stranded transmission costs contradicts her opinion that loss of revenue payments are due to Xcel relative to the transmission system. The transmission system near Slayton will continue to be utilized to serve the area and Xcel will continue to get all associated costs reimbursed from MISO. There are no stranded costs related to Xcel’s transmission assets around Slayton.

Q. Do you have anything to add regarding Xcel’s treatment of fixed production and transmission costs as they relate to a loss of revenue calculation?

A. Yes, I do. Mr. Mark Fritsch has provided rebuttal testimony for the City in this matter. In his rebuttal testimony he presents instances in the past when Xcel personnel (including Xcel witnesses Ms. Peterson and Mr. Krug) have stated publicly that Xcel's position is that fixed production - capacity, fixed production – energy, and transmission costs are avoidable in loss of revenue calculations.

Q. How much of the distribution cost component does Ms. Peterson state can be avoided by not serving Slayton?

A. Ms. Peterson states that only 1.3% of the distribution costs in Slayton are avoidable due to the acquisition of the system by Slayton. (Note – Ms. Peterson uses 1.3% in page 6 of 6 of Exhibit ___(LRP-1), Schedule 3, but references 1.4% on page 23 of her direct testimony). This conclusion is simply wrong. Slayton would be acquiring all the distribution system assets associated with serving the affected customers in this proposed acquisition, therefore Xcel would not have any further costs related to those assets after the acquisition is complete.

Even though Slayton is acquiring or paying for virtually all of Xcel's distribution facilities, Ms. Peterson claims they will only avoid 1.3 percent of distribution expenses. She states on page 23 of her direct testimony on lines 10-17:

> *"Our customers in Slayton do not just pay for the distribution equipment located in Slayton, but for a percentage of overall system costs for these categories of distribution infrastructure. While Slayton will purchase the specific infrastructure located within City limits, Slayton customers will also stop contributing to the overall system distribution costs. The Company will no longer receive revenues from Slayton customers related to overall system distribution costs, and there is no alternative source of revenue for these costs. As a result, these costs are unavoidable."*

Based on her direct testimony, 98.7% (100% less 1.3%) of the distribution costs paid by Slayton customers through the retail rates charged by Xcel actually subsidize the distribution expenses of other Xcel customers. This is a result that in my opinion is simply not possible. Aside from a portion of the substation which I address later in the rebuttal testimony, Xcel will clearly avoid all other distribution costs and they should be 100% avoidable.

Q. The last category listed by Ms. Peterson is customer costs, how much of these costs does she conclude are avoidable?

A. She states, again without providing relevant data for the calculation, that 27.1% of customer costs are avoidable.

Q. What costs does she state are included in the customer category?

A. On page 22, lines 9-11 of her direct testimony, she states:

> **"***Customer costs include costs related to service drops, meters, meter reading, customer service, back-office support, and portions of distribution lines and conductors."*

Q. What comprises her view that 27.1% of customer costs are avoidable?

A. She states that 27.1% of customer costs represent the service drops and meters for Slayton customers. She claims all other costs are not avoidable.

Q. Which costs does she say are not avoidable?

A. On lines 20-27 on page 22 of her direct testimony she states:

> **"***The Company does not expect to reduce the budget for customer service or back-office support. The Company will continue to incur the same amount of cost for these functions if Slayton exits the system, and as a result they will not be avoided.*
>
> *Further, the Company will continue to own all of the distribution lines, poles, and transformers that are partially included in the customer cost component, as described below."*

Q. Do you agree with her statements above?

A. No, I do not. In the first part above, I address these issues in my direct testimony, explaining that Xcel has a sufficiently large and diverse organization that it can easily adjust its operations to adjust customer systems for the loss of Slayton customers.

In the second part, she argues that "the Company will continue to own all of the distribution lines, poles, and transformers that are partially included in the customer cost component". This is not correct, those facilities are all part of the system that will be acquired by Slayton in this matter. Xcel will not continue to own <u>any</u> distribution lines, poles or transformers that would be part of the customer cost component for serving Slayton customers.

Q. What time period did Ms. Peterson utilize to calculate her loss of revenue payment?

A. On page 16 of her direct testimony, lines 18-20 she states:

> **"***I recommend a time period of 20 years. Our largest investments are in transmission and generation resources, with planning horizons of at least 20 and 30 years, respectively, as discussed by Company witness Sun."*

Q. What is the basis for her 20-year period for calculation of loss of revenue?

A. She relies on a combination of Xcel planning horizon and useful life of assets. Relative to planning horizon she states on page 13, lines 11-15 of her direct testimony:

> **"***Company witness Sun discusses the time horizons used in the Company's various planning processes in her testimony. Company witness Sun explains that Xcel Energy's planning horizon is between 10 and 30 years. This indicates that the relevant time period for calculating lost revenue should be no less than 10 years and no more than 30 years."*

She also states, relative to useful life, on page 15, lines 6-9:

> *"The investments we have made in our system, which were made with the understanding that Slayton would be part of our system, will last for decades. Distribution, Generation, and Transmission assets can have expected lives of between 30 and 74 years."*

Q. She focuses on three different asset classes in her discussion of planning horizons and useful life. Do you evaluate these issues for these assets differently than she does?

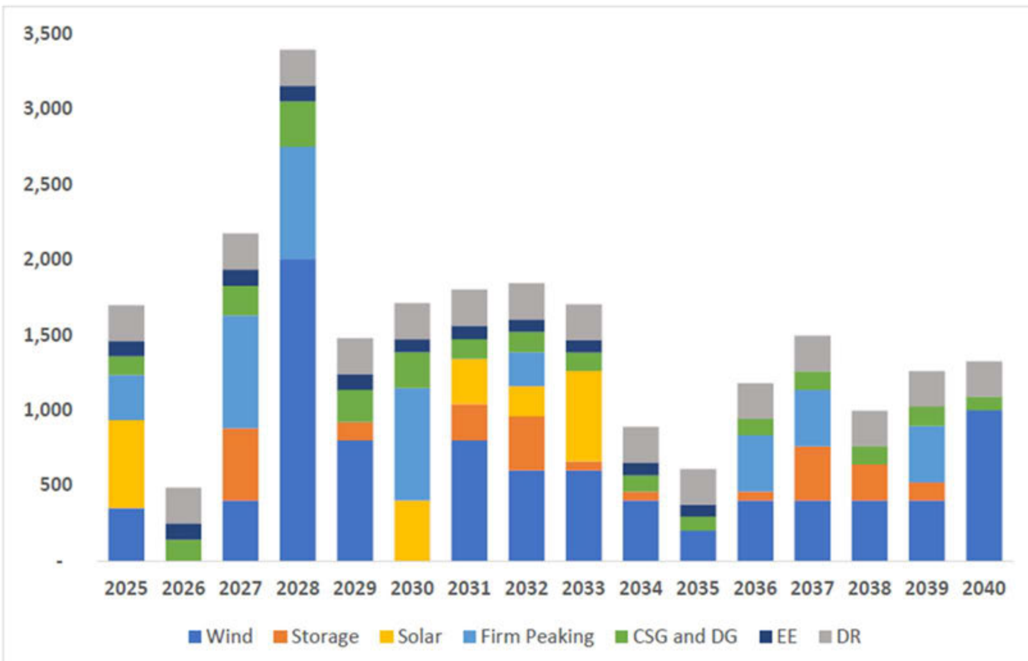
A. Yes I do. I don't necessarily disagree with the relative time periods she references for planning purposes or for the useful life of assets. But I strongly disagree with the applicability of those time periods as it relates to determining an appropriate compensation period for loss of revenue. Relative to generation assets, her 20-year period for compensation is based partially on the assumption that those assets are rendered useless and stranded for the remainder of their useful life due to Slayton's acquisition of the service territory. That is simply not true. I have addressed this issue in my direct testimony as well as above in this rebuttal testimony. Her theory also opposes Commission precedent on this issue, as I laid out in my direct testimony. This issue is directly tied to Xcel's responsibility, as laid out by the Commission in the City of Rochester case (SA-93-498), to adjust and mitigate its damages. Ms. Peterson's reference to the generation planning horizon implies that once plans are made, they cannot be adjusted. A review of Xcel planning documents shows this is not the case.

Q. What Xcel planning documents are you referring to?

A. As an indication of how Xcel's planning for generation assets evolves over time, I reviewed two of Xcel's filed resource plans. The following table 4-1 is from Xcel's 2024-2040 Upper

Midwest Integrated Resource Plan, Docket No. E002/RP-24-67 found on page 2 of chapter 4. It shows a summary of Xcel's Preferred Plan Resource Additions for the period 2025-2040.

Figure 4-1: Preferred Plan Resource Additions (MW)



	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Wind	350	0	400	2,000	800	0	800	600	600	400	200	400	400	400	400	1,000
Storage	0	0	480	0	120	0	240	360	60	60	0	60	360	240	120	0
Solar	585	0	0	0	0	400	300	200	600	0	0	0	0	0	0	0
Firm Peaking	298	0	748	748	0	748	0	225	0	0	0	374	374	0	374	0
CSG and DG	124	140	198	301	215	237	131	134	123	106	94	110	125	121	130	90
EE	103	108	108	105	103	87	91	85	82	86	80	0	0	0	0	0
DR	234	237	238	239	239	239	238	237	237	236	236	235	235	235	234	234

Shown below is a similar table from Xcel's 2016-2030 Upper Midwest Resource Plan Docket No. E002/CN-12-1240, this table 6 is found on page 68 of this filing.

Table 6: Preferred Plan Resource Additions

Preferred Plan

Resource	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource	Total
Small Solar	18	18	14	13	13	13	16	19	23	28	33	40	48	58	69	83	Small Solar	506
Large Solar	-	-	187	-	-	-	-	-	-	100	400	300	200	500	-	200	Large Solar	1,887
Wind	-	-	-	-	-	600	-	-	200	-	600	-	400	-	-	-	Wind	1,800
CT	-	-	-	-	-	-	-	-	-	-	876	438	219	219	-	-	CT	1,752
CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	CC	-

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Q. What information from the two resource plan additions tables above do you believe is relevant to this issue?

A. I would like to focus on the preferred plan additions for the year 2025 as contained in each plan. In the 2024 filing, it shows a total of 1,694 MW of additional capacity in 2025. In the 2016 filing, it shows 1,909 MW of additional capacity in 2025. This shows that Xcel, as is prudent utility planning, is continuously evaluating the need for generation additions and changing plans as necessary. Over an eight-year period (2016-2024), Xcel's plans for 2025 capacity additions changed by 215 MW. This is almost 54 times as large as the 4 MW of capacity currently utilized by Slayton. It is also equivalent to annual changes of almost 27 MW (215 MW divided by 8 years). The annual average change in 2025 capacity additions (27 MW) is 6.75 times larger than the 4 MW Slayton generation requirement. The planning horizon and useful life of generating assets is not relevant to the loss of revenue period, because Xcel can easily adjust quickly for this change in generating resources.

Q. Did Ms. Peterson also reference certain Federal Energy Regulatory Commission (FERC) cases from the late 1990s and early 2000s as a justification for a 20 year payment period?

A. Yes she did. She referenced *City of Las Cruces, New Mexico v. El Paso Electric Company*, 87 FERC ¶ 61,201, 61,750 (May 26, 1999) on page 15 of her direct testimony and *City of Alma, Michigan*, 96 FERC ¶ 61,163, 61,714 (July 30, 2001) on page 16.

Q. Do you believe these cases are relevant to this matter?

A. No I do not. These cases were both approximately 25 years ago. At that time, the concepts around regional planning of generating assets and the idea of markets for generation were in their infancy. For instance, the MISO market operations began in April 2005. Alma, MI is located in the MISO footprint. In New Mexico, the operating market changed with the passage of The Electric Utility Industry Restructuring Act of 1999. Attached as Attachment J is a summary of that Act.[8] This Act opened the generation market in New Mexico to competition, as stated at the end of page 2 of the summary open access to generation was scheduled to start January 1, 2001. The circumstances around these old FERC cases were different than under today's operating structure. I also point out that the decisions in both these cases included the following statement:

> *"In this case, the Commission is presented with a number of complex issues involving the calculation of stranded costs in a retail turned wholesale context. We wish to emphasize at the outset that our resolution of those issues here is limited to the particular facts and circumstances of this case. For that reason, our*

[8] Attachment J: Patrick T. Ortiz, The Electric Utility Industry Restructuring Act of 1999: Early Steps Toward Implementation, Natural Resources, Energy & Environmental Law Section of the State Bar of New Mexico (Winter 2000).

> *findings in this opinion are not intended to have generic application in any future retail-turned- wholesale cases that might reach the Commission for decision. Nor are our findings intended to apply to any wholesale requirements contract cases. Instead, the Commission necessarily must analyze each retail-turned-wholesale stranded cost case on a case- by-case basis, and must base its decision on the particular facts and circumstances of each case."*[9]

Q. Do the planning periods and useful life of transmission assets impact the consideration of time period for loss of revenue?

A. As outlined in Mr. Mitchell's rebuttal testimony and summarized in my testimony above, Xcel will have no stranded cost recovery related to transmission as a result of this acquisition by Slayton. They will continue to receive the full transmission cost recovery via MISO. With no transmission impact on Xcel, the planning periods and useful life of transmission assets is not relevant to the loss of revenue time period.

Q. How has Ms. Peterson referenced distribution systems relative to the time period for the loss of revenue period.

A. She makes reference to the useful life of distribution assets in lines 13-16 on page 14 of her direct testimony:

> **"***The five-year depreciation study filed in Docket No. E,G002/D-22-299 indicates that the useful life for distribution poles, towers, and fixtures is 44 years. The useful life for overhead conductors is 37 years, and 67 years for underground conduit."*

[9] *City of Las Cruces, New Mexico v. El Paso Electric Company*, 87 FERC ¶ 61,201, at *61,746 (May 26, 1999); *City of Alma, Michigan*, 96 FERC ¶ 61,163, at *61,712 to 61,713 (July 30, 2001).

Q. Do you agree that the useful life of distribution assets is relevant to the loss of revenue period?

A. No I do not. Ms. Peterson references distribution poles, towers, and fixtures as well as overhead conductors and underground conduit. Slayton will be acquiring all of these assets in the acquisition area, the useful life of these assets is not relevant to the loss of revenue period.

Q. For generation and transmission, Ms. Peterson references planning periods for these assets to justify her 20-year loss of revenue period. Does she reference distribution planning periods?

A. Ms. Peterson doesn't directly reference distribution planning periods, but she does make references to the direct testimony of Dr. Bixuan Sun with regard to planning periods. On page 4 of Dr. Sun's direct testimony (lines 5-6), she states "*Xcel Energy is required by Commission Order to file Integrated Distribution Plans (IDP) using a 10-year planning horizon and a 10-year Long-Term Plan"*. This plan was filed Nov. 1, 2023 in Docket E002/M-23-452. This document is referred to as a 10-year plan, but upon examination of the document, it is clear that it contains detailed plans for the next five years, not ten. On page 33 of the IDP it refers to a Near Term Action Plan and states:

> *"The first five years of our action plan will be focused on providing customers with safe, reliable electric service and continuing to make investments to modernize the distribution grid with foundational capabilities including AMI, FAN, ADMS, and FLISR. Throughout this IDP, we also discuss other near-term focus areas and priorities and our plans to invest in our system to ensure that we are able to continue to provide reliable electric service today and in the future. We outline how we intend to prepare for the future, enable the clean energy transition, maintain and enhance resilience and reliability, and modernize the grid."*

On page 21 of the IDP, the following Table 2 is shown:

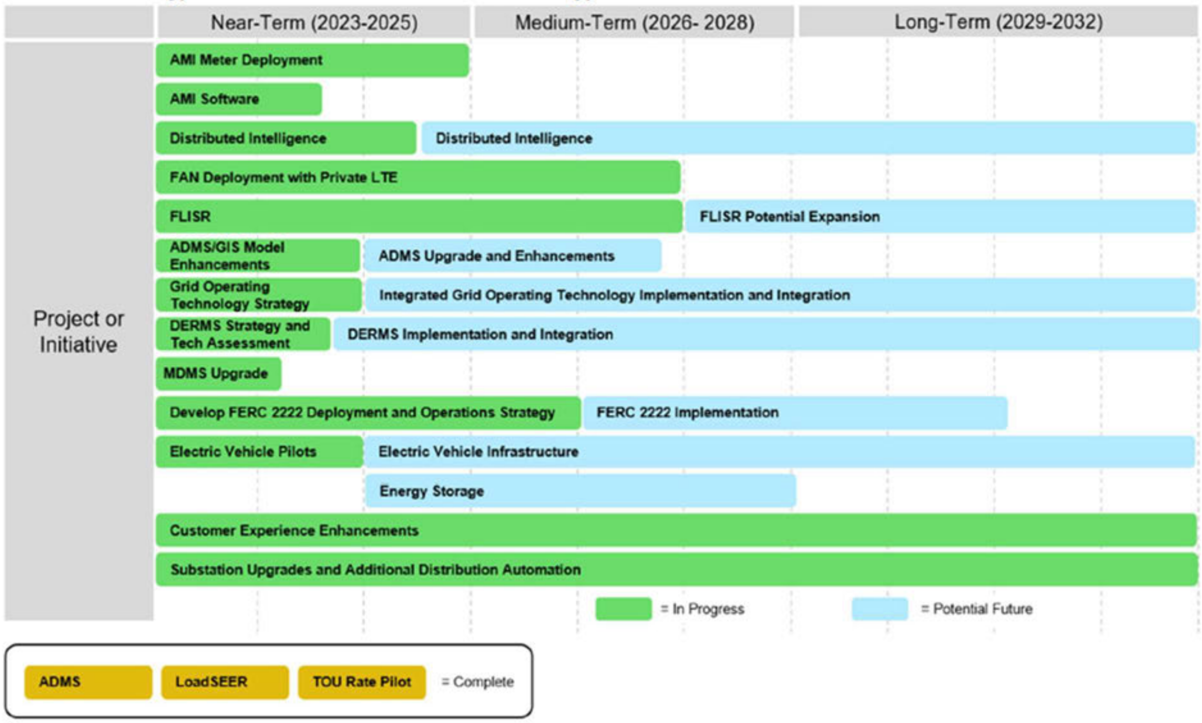
Table 2: Distribution Capital Expenditures Budget – State of Minnesota – Electric 2023-2027 (Millions)

IDP Category	Bridge Year 2023	Budget 2024	2025	2026	2027	2028	Budget Avg 2024-2028
Age-Related Replacements and Asset Renewal	$136.9	$179.4	$199.6	$231.2	$252.7	$272.4	$227.1
New Customer Projects and New Revenue	$50.1	$44.9	$47.6	$49.2	$51.1	$53.5	$49.3
System Expansion or Upgrades for Capacity	$35.8	$61.8	$93.2	$159.0	$193.3	$227.1	$146.9
Projects related to Local (or other) Government-Requirements	$29.2	$37.2	$39.6	$40.6	$41.6	$43.3	$40.4
System Expansion or Upgrades for Reliability and Power Quality	$40.9	$38.7	$55.4	$76.4	$201.2	$328.0	$139.9
Other	$70.8	$74.1	$55.1	$54.8	$56.4	$63.4	$60.7
Metering	$5.3	$4.1	$4.4	$4.7	$4.6	$4.5	$4.5
Grid Modernization and Pilot Projects	$115.4	$111.3	$56.3	$40.9	$33.5	$10.8	$50.6
Non-Investment	($2.1)	($4.0)	($4.0)	($4.0)	($4.0)	($4.0)	($4.0)
Electric Vehicle Programs	$9.3	$8.9	$1.4	$18.4	$36.9	$71.8	$27.5
TOTAL	**$491.7**	**$556.5**	**$548.5**	**$671.2**	**$867.2**	**$1,070.7**	**$742.8**

This Table 2 shows that within the 10-year plan, only a 5-year specific budget for distribution capital is presented. The detailed planning period within this plan is actually five years.

In the 10-year plan, there are also medium-term and long-term designations. Figure C-1 shown below is from page 35 of the IDP.

Figure C - 1: Illustrative Long-Term Grid Modernization Plan



As shown, the near-term and certain medium-term projects are in progress, the majority of the long-term projects are listed only as ”potential”.

In my direct testimony I reference the November 1, 2024 Compliance Annual Update to Xcel’s 2023 Integrated Distribution Plan, Docket No. E002/M-23-452.[10] Within the introduction of that annual update it states: *“The latest five-year budget we outline in this annual update reflects the Company’s ongoing commitment to maintaining and enhancing the reliability and resilience of our distribution system assets.”*

This Commission-required IDP filing and its annual update both focus on a 5-year plan for specific distribution project expenditures. Ms. Peterson also references a five-year

[10] *See* Berg Direct Testimony, page 47.

depreciation study related to distribution assets. That quote is shown above regarding Docket No. E,G002/D-22-299.

Q. What do you conclude relative to the connection between distribution planning and a proper loss of revenue period?

A. If a planning period is to be utilized as a reference point to determine the loss of revenue period, the distribution planning period, not the generation or transmission planning periods would be most appropriate. Slayton's acquisition primarily impacts Xcel's distribution system and planning activities. The Xcel distribution planning period would support five years as an ample lost revenue payment period.

Q. Do you agree that planning periods should be the basis for establishing a loss of revenue time period?

A. I think planning periods are one aspect for consideration in setting a loss of revenue period. However, the final decision should be based on the particular facts in each case, with the final determination based on the ability of the incumbent utility to adjust its system to the loss of load/system. I addressed many aspects of Xcel's ability to adjust its system and operations in my direct testimony.

Q. What loss of revenue period did you propose in your direct testimony?

A. Five years.[11]

Q. Do you have any additional comments regarding Xcel's ability to adjust its system and operations relative to this proposed acquisition by Slayton?

[11] *See* Berg Direct Testimony, pages 37-41.

A. Yes, in November of 2024, Xcel submitted an Application for Authority to Increase Electric Rates in Minnesota, Docket No E002/GR-24-320. The requested rate increase by Xcel was 9.6% in 2025 with an additional increase of 3.6% in 2026. In her November 1, 2024 cover letter with the application, Regional VP, Regulatory and Pricing, Amy Liberkowski provides Xcel's stated justification for the rate increase.[12]

The items listed by Ms. Liberkowski in her explanation justifying the rate increase include "transforming our generation fleet", "creating a more advanced distribution grid", "transformation of our overall delivery system, and better meeting new customer expectations." She goes on to say the increase "… also enables the Company to continue improving the customer experience while maintaining safe and reliable energy service for our customers."[13]

Q. How much additional revenue would Xcel's requested rate increases generate?

A. In the same submittal by Ms. Liberkowski I reference above, she states that the increases would generate $353.3 million in 2025 and an additional $137.5 million in 2026.[14] This total is $490.8 million.

Q. Why are Ms. Liberkowski's comments regarding the rate increase relevant here?

A. In its request to raise rates, Xcel states that they are transforming almost every part of their system and operations and requires the rate increase to fund this transformation.

[12] Attachment K: Cover Letter from Amy Liberkowski to Will Seuffert, Excerpted from Xcel's Application for Authority to Increase Electric Rates in Minnesota, dated Nov. 1, 2024, in Docket No E002/GR-24-320.
[13] *Id.* at 2 (page 1 of the letter).
[14] *Id.*

While Xcel is spending an additional $490.8 million annually in part to make this significant system transformation, it is reasonable to assume they can make the transformation while also adjusting for the very small loss of the Slayton customer base and facilities within five years. Mr. Mark Fritsch, in his rebuttal testimony on behalf of the City of Slayton, makes additional relevant statements regarding the ability of Xcel to adjust its system for the loss of Slayton.[15]

Q. Does Ms. Peterson, in her direct testimony, include any values for "Integration Expenses" due to Xcel in this matter?

A. Yes she does. Her comments on Integration Expenses begins on page 31 of her direct testimony. She has identified integration expenses related to 1) Meter Integration Expenses; 2) Continued Service Integration Expense; and 3) Distributed Energy Resources.

Q. How much compensation has she set forth for meter integration?

A. As shown in her Table 4 from page 46 in her direct testimony which I reference above, she has included an ***estimated*** value of $140,000. This compensation is for Xcel to remove its meters in Slayton. The City will be installing different meters to serve the customers. Her estimate is stated in lines 16-17 on page 33 of her direct testimony where she says: *"At this time, the Company estimates that the labor cost of removing its meters would be approximately $140,000."* She also states on lines 23-24 on page 33 that: *"The estimate also includes internal labor cost based on the assumption that it will take 15 minutes to reservice one meter."*

[15] *See* Rebuttal Testimony of Mark Fritsch, pages 12-16.

Q. Do you have any comments regarding her estimate for meter integration?

A. Assuming 1235 customers (meters) in Slayton (as taken from Ms. Peterson's Exhibit___(LRP-1), Schedule 3) her estimate results in a cost estimate of $113.36 per meter. This estimate would appear to be high and I would suggest that Xcel provide more detail to the Commission before an amount is awarded. It is also possible that the City could perform the meter change-out more efficiently by performing it concurrently with the installation of new City meters. I also believe the estimate should reflect the value of these meters to Xcel. The reserviced meters will be available to Xcel for use at other locations in its system which will allow Xcel to avoid the cost of 1235 new meters.

Q. How much compensation has she set forth for continued service integration?

A. As shown in Ms. Peterson's Table 4 from page 46 in her direct testimony which I reference above, she has included an ***estimated*** value of $15,000. This estimate does not appear unreasonable. She also states that other work may be required and says in lines 3-6 on page 35 of her direct testimony: *"The Company proposes that any expenses required to continue to provide service to Xcel Energy customers should be included in the just compensation payment, and commits to work cooperatively with Slayton to identify such work."* I understand the City would also welcome the opportunity to work cooperatively with Xcel on these issues to ensure that these expenses are warranted and reasonable.

Q. Does she provided an estimate for distributed energy resources integration?

A. No she does not. Ms. Peterson's testimony breaks this category into two areas: 1) Community Solar Gardens (CSG) and 2) Distributed Energy Resources (DER), rooftop solar, located at customer locations in Slayton.

Q. Do you have any comments regarding her statements relative to CSGs?

A. I would characterize Ms. Peterson's statements on these topics as raising a number of potential issues with no quantifiable solutions presented.

Q. Does she present a technical concern related to the solar gardens?

A. Yes, lines 1-17 on page 38 of Ms. Peterson's direct testimony presents, from her point of view, a potential technical issue related to system stability that she says may require compensation to address. Mr. Mark Mitchell, in his rebuttal testimony, has addressed the technical aspects of this concern, and concludes that it is not a valid concern, given the sizes of the Slayton load and the nearby CSGs. Ms. Peterson does state in lines 13-17 of her direct testimony on page 38 the following: *"The Company requests that the cost of any transmission or other engineering studies caused by Slayton exiting the system be included in just compensation, along with the costs for any upgrades identified in these studies, and that the proposed purchase not take place until after these upgrades have been completed."* It is not reasonable to require the cost of these studies as part of the compensation or to delay the proposed purchase until all studies and upgrades have been completed.

Q. She also makes reference to the rooftop solar customers located in Slayton, do you have comments on this issue?

A. Yes, as a municipal utility in Minnesota, Slayton would be required by Minn. Stat. 216B.164 to provide net metering service to these customers. Xcel also operates under that same statute regarding customers with roof top solar. Those customers would move from the Xcel program to the program adopted by Slayton in compliance with the applicable statute.

Q. Does Ms. Peterson, in her direct testimony, include any compensation for 'Other Appropriate Factors' due to Xcel in this matter?

A. Yes, she does. On page 40, lines 22-24 of her direct testimony she states: "*The Company has identified one additional cost that should be included in just compensation. Slayton's exit will result in stranded costs and reduction in value for the Slayton substation that should be included in just compensation.*"

Q. What is she claiming regarding the Slayton substation?

A. On lines 7-15 on page 41 of her direct testimony she states:

> "*The Slayton West substation (SLW) is located just outside the City limits. It is connected to the 69 kV transmission line that runs through town. SLW was constructed in 2006 and 2007 with a capacity of 14 kV.*
>
> *Before SLW was constructed, Slayton was served by an older substation with a capacity of approximately 4 kV. In 2006, the Company determined that more capacity and improved voltage were required to serve the City of Slayton and constructed SLW. After SLW was completed, the original Slayton substation was removed.*"

Q. Is there what you believe to be a typographical error in her statements above?

A. Yes, she refers to substation capacity twice as '14 kV' and '4 kV'. I am certain she meant to say 14 MVA and 4 MVA. MVA is a measure of substation capacity, kV is a voltage measurement and is not applicable to this situation. MVA stands for Megavolt amperes.

MVA capacity of a substation is equivalent to the Megawatt (MW) load it is capable of serving.

Q. Typographical adjustments aside, what is her argument for "other appropriate factors" compensation to Xcel regarding the substation (SLW)?

A. On page 43 of her direct testimony, lines 4-9 she states:

> **"***The Company built SLW with the expectation of continuing to serve Slayton. It would not have done so if Slayton were not on the system, and it certainly would not have replaced the old Slayton substation with SLW. It was prudent for Xcel Energy to construct SLW, but Xcel Energy's other customers should not have to pay for SLW if it becomes a stranded asset. Instead, Slayton should pay for a portion of SLW."*

On lines 12-21, she adds:

> *"Slayton should pay for a percentage of SLW based on the ratio of how much SLW is used by customers inside Slayton compared to customers outside Slayton that will remain after the proposed purchase. Based on the Company's analysis, the customers located in Slayton have an annual consumption of approximately 20,501,184 kWh of usage, while the customers outside Slayton will have approximately 253,055 kWh of consumption each year. 98.8 percent of the load served by SLW is located inside Slayton and would exit our system if the proposed purchase moves forward. As a result, 98.8 percent of the SLW book value would be stranded and should be included in just compensation, an amount of $1,131,354."*

Q. What is your view of her argument that Slayton should pay Xcel $1,131,354 for stranded substation costs in SLW?

A. I disagree with this conclusion. The peak load in Slayton, based on information from Xcel, has been established to be 4 MW. I have shown above in this rebuttal testimony that no growth is expected in Slayton. The original 4 MVA of capacity in the Slayton substation referenced by Ms. Peterson was sufficient to serve the 4 MW Slayton load. Xcel made the decision to build the new SLW substation and size it at 14 MVA. The 14 MVA capacity is 10 MVA larger than needed to serve Slayton. By Ms. Peterson's logic, SLW was 71% (10 MVA divided by 14 MVA) stranded the day it went into service.

Q. Ms. Peterson states that the SLW was built "with the expectation of continuing to serve Slayton", does SLW serve any other purposes?

A. As I outlined in my direct testimony (page 29 lines 7-26 and page 30 lines 1-2) and referenced by Ms. Peterson in her direct testimony on page 36, lines 1-3 when she states **"***There are three CSGs located near Slayton, which are interconnected to the substation that provides service to Slayton. The gardens are located outside of Slayton City limits."* The Community Solar Gardens (CSGs) require the substation capacity of SLW to deliver their output to the system. Xcel, as I referenced in my direct testimony, has plans for additional CSGs at that location. The substation will not be 98.8% stranded, as stated by Ms. Peterson.

Q. Are current Slayton customers paying for the full cost of ownership and operation of SLW substation?

A. No, they are not. Xcel's statewide retail rates, which Slayton customers pay, are based on each customer paying its share of Minnesota system-wide substation costs. It is an incorrect statement to claim that Slayton customers are currently paying the full cost of the SLW substation.

Q. From a loss of revenue and rate perspective, does it make sense to charge Slayton for 98.8% of the substation cost, yet still allow Xcel to maintain ownership of SLW for use for interconnecting current and planned CSGs?

A. No, it does not make sense for Slayton to pay Xcel for nearly the full cost of the substation asset, while Xcel is allowed to keep the asset for utilization to serve customers and interconnect existing and planned CSGs to the greater electric system. Xcel made the decision to size the SLW capacity as it did. Slayton did not request 14 MVA of capacity to serve its 4 MW load. Ms. Peterson completely ignores the value of SLW to Xcel as it relates to the existing and planned CSGs. For Xcel to recover 98.8% of the substation cost here would be a windfall to Xcel, in my opinion.

Q. By Ms. Peterson's logic, what would Slayton need to pay Xcel for its share of the "stranded" SLW capacity?

A. On page 41 of her direct testimony, on line 18 Ms. Peterson states that the current book value of SLW is $1,145,319. Slayton's load currently comprises 28.6% of the substation capacity (4 MW divided by 14 MVA). If you multiply $1,145,319 times 28.6% the result is $327,561.

Q. In your direct testimony, did you account for the substation capacity in your loss of revenue calculation?

A. Yes I did. In my direct testimony I recommended a 5-year payment of 4.2 mills/kWh related to the Primary Distribution Substation function.

Q. How much would your payment amount to over the 5-year period?

A. Utilizing the 20,501,184 kWh of annual sales to customers in Slayton as shown by Ms. Peterson in line 16 on page 43 of her direct testimony for a period of 5 years, I calculate $430,525 in total substation compensation (20,501,184 times $0.0042/kWh times 5 years). This would reimburse Xcel for 100% of the Slayton allocated cost of the SLW substation plus an additional $102,964 for other substation related expenses such as operation and maintenance expenses.

Q. Should the substation component be included as an "other factor" as suggested by Ms. Peterson?

A. No, it should be included in only the loss of revenue component as I have proposed. To include it in loss of revenue component and have an additional lump sum payment results in double payment to Xcel for the substation asset.

Q. If Ms. Peterson's total compensation for all factors were awarded in this case, what would the impact be on rates for the citizens of Slayton?

A. As a baseline for annual revenue from Slayton, I will utilize the $2,914,221 annual sales as stated by Ms. Peterson in her direct testimony, Exhibit___(LRP-1), Schedule 3, page 1 of 6.

Q. How would you quantify her just compensation amounts?

A. In her Table 4, which I referenced above, for the loss of revenue component she suggests an annual payment of $3,645,618, I will use that annual number for this comparison.

Q. How will you reflect her other lump sum payments?

A. Her suggested payments for ”value of property”, ”meter integration expense”, ”continued service integration expense”’ and the “stranded Slayton West Substation”, as presented in her Table 4, total $4,507,007. If I assume Slayton would finance that amount for 20 years at an interest rate of 4.5%, the total annual principal and interest payment would be $346,481.

Q. What would the total annual impact be on Slayton customers?

A. The sum of the loss of revenue annual payment and the debt service for the lump sum amounts would be $3,992,099. This amount equals 137% ($3,992,099 divided by $2,914,221). This shows that the citizens of Slayton would require a 137% rate increase to pay the amounts suggested by Ms. Peterson.

Q. Would this be an affordable outcome for Slayton?

A. No it would not. Slayton would not be able to move forward and complete this transaction at this level.

Q. Does this result make sense from an equitable perspective of the facts?

A. For Slayton to pay Xcel a total amount equivalent to over 100% of the current revenues for a 20-year period does not make sense. This implies that the negative impact on Xcel is more than twice the annual revenue generated in Slayton for a 20-year period.

Direct Testimony of Bixuan Sun

Q. Which areas of the direct testimony of Xcel witness Bixuan Sun will you be addressing?

A. I will be addressing certain parts of her testimony as it relates to planning periods by Xcel as they relate to appropriate time period for loss of revenue compensation, and Xcel's ability to adjust generation plans and the value of capacity in the MISO market.

Q. What planning periods does she reference in her direct testimony?

A. I will specifically comment on Dr. Sun's references to generation planning, transmission planning and distribution planning.

Q. What planning period does she reference for generation?

A. On page 3 of her direct testimony, lines 12-17, she states:

> *"This 30-year modeling horizon is a regulatory requirement. Xcel Energy's generation fleet does not just serve customers in Minnesota, but also the entire Upper Midwest region which includes service territories in Minnesota, North Dakota, South Dakota, Wisconsin, and Michigan. The Public Service Commission of Wisconsin (PSCW) requires that capacity expansion modeling be conducted using a 30-year evaluation period."*

She adds in lines 1-2 on page 4 of her direct testimony: *"Xcel Energy's planning horizon for generation resources is at least 30 years for modeling purpose."*

Q. How does this planning period generation for modeling purpose impact an appropriate loss of revenue period?

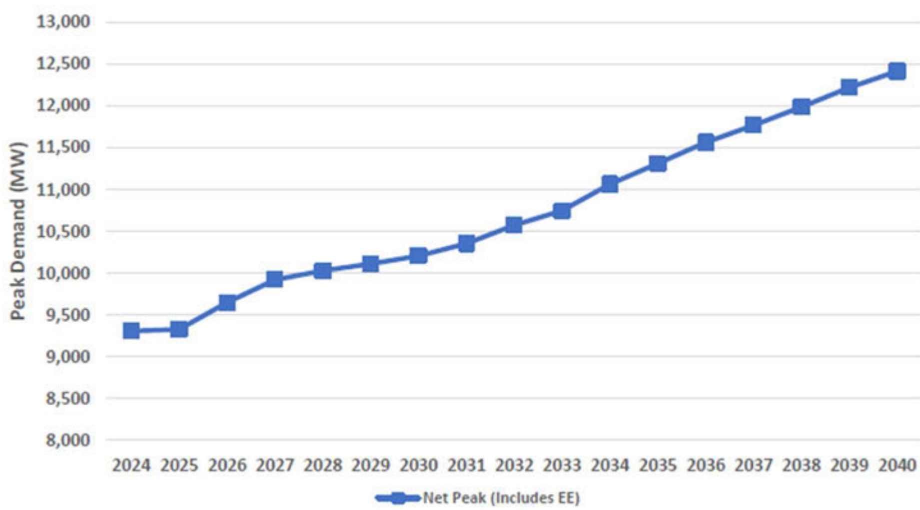
A. I don't believe its relevant. For it to impact the proper loss of revenue period you would need to assume that Xcel is unable to make any adjustments in its plans once they are made. There is an implication in Sr. Sun's analysis that once generation plans are made, they cannot be altered. As I point out above in my discussion of Ms. Peterson's direct testimony, Xcel's plans for generation are constantly changing in their 30-year generation plans. Prudent planning would dictate that all utilities should constantly be revisiting their plans to ensure they have the proper balance of resources.

As Dr. Sun states, Xcel does its generation planning for the entire upper Midwest region. In Xcel's 2024-2040 Upper Midwest Integrated Resource Plan Docket No. E002/RP-24-67, they include Figure 3-2 shown below:

Xcel Energy

Docket No. E002/RP-24-67
Resource Plan Chapter 3 - Page 3 of 29

Figure 3-2: NSP System Median Base Summer Peak Demand (MW)
(Includes modeled EE Adjustment)



The Figure 3-2 shown above graphs Xcel's (NSP) projected peak demand for resource planning for the period 2024-2040. Looking at the graph, it appears that the regional peak demand increases from approximately 9,400 MW in 2025 to 12,500 MW by 2040. From the same IRP report, a portion of Table 3-4 is presented below. This shows Xcel's (NSP) generation capacity obligation for the same 2024-2040 period.

Table 3-4: Reference Case Load and Resources,[24] 2024-2040 Planning Period, Summer Season

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
System Needs: Summer																	
Forecasted gross load	10,735	10,769	11,087	11,361	11,468	11,489	11,550	11,518	11,621	11,671	11,757	11,817	11,920	11,954	12,047	12,148	12,226
Adjustment to Load from non-bundled Energy Efficiency	(1,347)	(1,277)	(1,195)	(1,132)	(1,072)	(1,004)	(927)	(839)	(772)	(718)	(623)	(524)	(482)	(461)	(482)	(513)	(602)
Adjustment to Load from EVs and Beneficial Electrification	20	35	54	81	115	158	213	361	482	620	768	919	1,058	1,193	1,324	1,453	1,578
Forecasted Net Load	9,408	9,526	9,946	10,311	10,511	10,643	10,835	11,040	11,331	11,573	11,902	12,212	12,496	12,686	12,890	13,088	13,202
MISO System Coincidence	92.24%	92.24%	92.24%	92.24%	92.24%	92.24%	92.24%	92.24%	92.24%	92.24%	92.24%	92.24%	92.24%	92.24%	92.24%	92.24%	92.24%
Coincident Load	8,678	8,787	9,174	9,511	9,695	9,817	9,994	10,183	10,452	10,675	10,979	11,264	11,526	11,702	11,890	12,073	12,178
MISO Planning Reserve Margin (UCAP)	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%
NSP Obligation (Summer)	**9,459**	**9,578**	**10,000**	**10,367**	**10,568**	**10,700**	**10,894**	**11,100**	**11,393**	**11,636**	**11,967**	**12,278**	**12,564**	**12,755**	**12,960**	**13,159**	**13,274**

This table shows Xcel's (NSP) obligation for generating resources increasing from 9578 MW in 2025 to 13,274 MW in 2040. The capacity freed up due to the loss of Slayton load is estimated at 4 MW. This equals 0.04% of Xcel's 9,578 MW generation obligation in 2025. Dr. Sun is essentially testifying that over a 30-year planning period, there is nothing Xcel can change in its generation planning to adjust for the loss of load equal to four one-hundredths of one percent of its generation capacity requirements. Additionally, Xcel's generation requirements from 2025 to 2026 increase by 422 MW (10,000 MW less 9,578 MW). The loss of Slayton would reduce that increase to 418 MW (422 MW-4 MW).

Q. Dr. Sun also references transmission planning periods, are they relevant to the loss of revenue period?

A. No they are not. On page 4 of her direct testimony, lines 9-12 Dr. Sun states:

> *"The Company engages in long-term transmission system planning in accordance with MISO requirements and processes. MISO's Long-Range Transmission Planning (LRTP) process uses a 20-year time horizon to evaluate what transmission projects are needed to serve the region."*

A key statement related to transmission planning is her statement that Xcel does its long-term transmission planning "in accordance with MISO requirements and processes." As I have discussed above, and as included in the rebuttal testimony of Mr. Mark Mitchell, Xcel receives all transmission revenue requirements from MISO. The loss of the Slayton load has no impact on Xcel's receipt of transmission operating costs or ownership costs. The transmission planning period is not relevant to the loss of revenue calculation because Xcel will not incur any loss of transmission-related revenue due to the Slayton acquisition.

Q. The third planning period you mention from Dr. Sun's testimony is related to distribution planning, what comments do have regarding her testimony on this matter?

A. Dr. Sun only makes one reference to the distribution planning period which I also referred to above in my discussion of Ms. Peterson's direct testimony. On page 4 of Dr. Sun's direct testimony, lines 5-6 she states: *"Xcel Energy is required by Commission Order to file Integrated Distribution Plans (IDP) using a 10-year planning horizon and a 10-year Long-Term Plan."* I will reiterate points I made above on this issue. The detailed capital plans within the 10-year IDP plans are limited to five years. Also, they are also required to update this plan on an annual basis so the 5-year capital plan is a rolling 5-year plan with the expectation that it would be updated every year as necessary. Additionally, as I discussed above in my comments on Ms. Peterson's direct testimony, my suggested payment for the substation (the only portion of Slayton distribution that Xcel will retain) over a period of 5 years is sufficient to reimburse Xcel for its distribution-related loss of revenue.

Q. You also reference Dr. Sun's statements regarding the value of capacity in the MISO market, what comments do you have on this issue?

A. Dr. Sun presents values of Slayton capacity in the MISO market based on MISO market prices. The numbers she presents are very low even though I generally agree with the MISO capacity market numbers she quotes. For instance, on page 11 of her direct testimony she lists the 2025/2026 clearing price of $666.50 per MW-day for the summer season. This matches the value I reported in my direct testimony. The Slayton load represents 4 MW of capacity that would be freed up and available for Xcel to sell into the MISO market. The summer season is June-August, which is 92 days long. By my calculation, 4 MW times 92 days times $666.50/MW-day would yield a MISO capacity market value of $245,272. However, in her direct testimony she claims the value is only Not-Public Data less than my estimate. She does not provide a written summary of her calculations, but they are shown in her Exhibit___(BS-1), Schedule 2, page 1 of 1. Upon examination of her exhibit, I believe I understand her approach.

In her exhibit she has a column designated as NSP PRMR (MW), this appears to represent NSP's total Planning Reserve Margin Requirement (PRMR) in MW. This would be NSP's required generation to meet MISO capacity requirements. She then shows the seasonal market prices, the Planning Resource Auction, Auction Clearing Price (PRA ACP) on a $/MW-day price. Her next column is NSP's "Net PRA Revenue". NSP pays the ACP for all its generation requirement and receives revenue for all its generating resources. This net PRA revenue would represent NSP's excess MW of generation available above its PRMR requirement. She then allocates a share of that net revenue to Slayton based on Slayton's share of NSP's total MW PRMR.

Q. Do you believe her method is valid for quantifying the value of freed up Slayton capacity?

A. No I do not. It is valid for calculating what Slayton customers share of Xcel's net PRA revenue under current operating and service to Slayton by Xcel. All of Xcel's current customers have an equal share based on their load share of Xcel's net PRA revenue. Dr. Sun's analysis is incorrect because it does not value the marginal cost benefit to Xcel of 4 MW of new excess capacity resulting from the loss of the Slayton load. This is 4 MW of additional capacity that will increase the total net PRA revenue to Xcel. To judge the overall financial impact of this new excess capacity, the full value of the 4 MW of capacity should be weighed against any deemed loss of revenue associated with the portion of rates paid by Slayton customers dedicated to generating capacity.

Q. What value do you calculate for this 4 MW of available capacity?

A. Based on the MISO capacity prices I included in my direct testimony, the level annualized auction price for 2025/2026 planning period was $217 per MW-day. This market price of $217/MW-day times 4 MW times 365 days equals $316,820.

Q. From Dr. Sun's Exhibit___(BS-1), Schedule 2, page 1 of 1, she shows a value of Slayton's share of current net PRA revenue for the 25/26 period of Not- **is this value still relevant?**

A. Yes, Slayton's current share of the net PRA revenue will now be available to all remaining Xcel customers and should be added to the incremental value of the freed up generation I calculate above. The total amount of value would be Not-Public Data Not-Public

Q. How does this compare to your evaluation of the fixed capacity costs for serving Slayton?

A. On page 22 of my direct testimony, I presented by analysis of the per kWh costs to serve Slayton separated by Revenue Requirement items as taken from Xcel's last rate case cost of service analysis. There are two items in that table representing generation capacity costs. The Capacity-Related Summer Peak Production ($0.0147/kWh) and the Capacity-Related Winter Peak Production ($0.0046/kWh). The total of these two items is $0.0193/kWh. Based on total annual sales in Slayton of 20,501,185 kWh (as provided by Ms. Peterson), the capacity costs to serve Slayton would be $395,673.

Q. The MISO capacity value you have calculated Not-Public **is less than the allocated capacity cost value ($395,673), does this indicate there would be a net loss to Xcel for capacity in this matter?**

A. No it does not. This analysis shows that the value in the market and the net cost to Xcel of capacity from its cost-of-service data are very close. However, this must also be combined with the other factors I have included in this rebuttal testimony and my direct testimony regarding Commission precedent regarding capacity in loss of revenue, the ability of Xcel to adjust its operations, the need for new additional capacity per Xcel's IRP planning documents, and market value. Xcel has numerous financial and operational options to mitigate any perceived negative generation impact resulting from loss of four one-hundredths of 1 percent (as calculated by Dr. Sun) of its load.

Direct Testimony of Allen Krug

Q. Which areas of the direct testimony of Xcel witness Allen Krug will you be addressing?

A. I will be addressing certain aspects of his testimony in the area he entitles: IV. Slayton's Plan and Statutory Framework.

Q. What comments by Mr. Krug would you like to respond to?

A. On page 9 of his direct testimony Mr. Krug begins a discussion around the potential relationship between a new municipal electric utility in Slayton and Nobles Electric Cooperative (Nobles). On lines 14-20 he lists the following items related to draft agreements between Slayton and Nobles:

- Nobles would provide electricity to the City
- Nobles would operate and maintain the distribution system in Slayton
- Nobles would read meters, send bills to customers, and bills would be collected by Nobles
- Nobles also would handle legally required disconnection notices and disconnections
- The City does not plan to hire any people to staff a municipal electric utility
- The City appears to be planning for Nobles to handle every function that a utility is responsible for.

Q. Mr. Krug's first comment listed above is related to the potential for Nobles to provide electricity to the City. Does he disagree with this potential arrangement?

A. I don't know if he disagrees with the arrangement or not. At the top of page 10 of his direct testimony (lines 1-4) he states: *"It is not clear whether Slayton would be a wholesale* *customer of Nobles or whether Nobles has authorization to provide wholesale electricity service. A draft agreement between Slayton and Nobles state that the City would be a member of Nobles."* Virtually every municipal utility in Minnesota buys its power or a portion of its power from someone else. I understand 'wholesale power' as a general utility concept but I cannot address whether Nobles has "authorization" to provide wholesale service. I know that Nobles receives its power from Great River Energy (a Minnesota Generation and Transmission Cooperative) and Nobles is a member of Great River Energy. I am confident that Nobles has or can obtain authorization from Great River Energy to undertake the proposed arrangement with Slayton.

Q. The remaining bullets referring to Mr. Krug's direct testimony all appear directed at a potential arrangement between Slayton and Nobles for various services related to the operation of the municipal utility. What is Mr. Krug's assessment of this possible arrangement?

A. He states in lines 8-12 on page 9 of his direct testimony: *"Based on the information received from the City, it does not appear that Slayton has or intends to develop the capability to operate a municipal utility. Instead, customers would receive service from Nobles Electric Cooperative (Nobles) and Nobles would perform most or all the functions that are normally performed by a utility."*

Q. How do you respond to his statement above?

A. His testimony suggests that Slayton is not actually creating a municipal utility. I disagree with his statement: *"… it does not appear that Slayton has or intends to develop the* *capability to operate a municipal utility.*" Slayton does intend to develop the capability to operate a municipal utility, they intend to hire a qualified entity to perform those duties on a contract basis. I am aware of no requirement that a municipal utility must have its own staff to qualify as a municipal utility. The concept of a municipal utility is focused on ownership and governance, not operating personnel.

Q. Do you have any additional comments on his statements?

A. Yes, Mr. Krug says *"… customers would receive service from Nobles Electric Cooperative".* This is an incorrect statement. The City will own all the local infrastructure in Slayton. My understanding is the City plans to provide local control and regulation of the local utility under the authority of the City Council. The City will also set its own rates for service. This means Slayton customers will not pay Nobles retail rates, they will pay Slayton Municipal Electric rates which will be designed to collect the City's required revenue requirements, some of which will be based on services provided by Nobles.

Q. Is it unusual for a municipal utility to contract with other entities to provide services for the municipal utility and its customers?

A. It is not unusual, particularly for smaller municipal utilities.

Q. Are you aware of any specific instances of municipal utilities contracting for services?

A. I have not done an exhaustive search among municipal utilities, but I know of many through my work as a consultant.

Q. Can you share the specific instances you are aware of?

A. Yes. Minnesota Power (an investor owned utility in NE Minnesota) sells wholesale power to 14 municipal utilities in the northeast portion of the state. For three of these municipally owned utilities (Biwabik, Gilbert and Randall) it contracts to maintain their local distribution system. For Randall, it also operates and reads its meters. The City of Arlington, MN contracts with McLeod Coop Power to operate and maintain its local electric infrastructure.

Q. Do you know of other examples?

A. Yes, Missouri River Energy Services (MRES) is a joint action agency located in Sioux Falls, SD. MRES has 61 member municipal utilities located in Minnesota, North Dakota, South Dakota and Iowa. MRES sells power to each of its members. MRES also has a distribution maintenance program that gives it municipal utilities the option to contract with MRES to maintain electric distribution lines, substations, transformers, breaker, meters and other related services.[16]

MRES currently provides full distribution management services to 6 Minnesota municipal utilities (Barnesville, Benson, Jackson, Luverne, Olivia and Ortonville). It also provides supplemental distribution management services to 15 municipal utilities, including five in Minnesota (Adrian, Grove City, Henning, Lake Park and St. James). MRES provides certain meter reading services to some of its members.

Q. Does Mr. Krug have any additional comments regarding any relationship between Slayton and Nobles that you wish to respond to?

[16] This program summary is available at https://www.mrenergy.com/services/distribution-maintenance.

A. Yes, on page 11 he refers to a potential financial relationship between Slayton and Nobles. Lines 6-9 he states: *"Based on information obtained in discovery, Slayton and Nobles have discussed the possibility of Nobles purchasing the bond that Slayton will use to finance its purchase of Xcel Energy's property. If this were to take place, the money used to purchase Xcel Energy's property would come from Nobles."*

I do not believe this potential arrangement is relevant. Whether Slayton borrows money from Nobles, a bank, the bond market or any other legal means, Slayton will be obligated to repay the amount borrowed which will necessitate charging rates to Slayton customers that generate sufficient revenues to repay the debt.

Q. Does Mr. Krug makes reference to a change in the way power will be delivered to Slayton after municipalization?

A. Yes, on pages 11-12, lines 16-24 on page 11 and lines 1-4 on page 12, he states the following:

> *"Q. HOW WOULD CUSTOMERS IN SLAYTON ACTUALLY RECEIVE ELECTRICITY?*
> *A. Customers in Slayton currently receive electricity from an Xcel Energy transmission line running along the southern border of the City, which is connected to the regional transmission system. Xcel Energy owns a distribution substation just outside City limits and the distribution feeders in Slayton are connected to this substation.*
>
> *After the proposed purchase, the City has indicated that it will no longer take service from Xcel Energy's transmission line or substation. Instead, the City indicates that Nobles will construct a new substation for Slayton, which would be connected to the regional grid by a Great River Energy transmission line extension, apparently bypassing the existing Xcel Energy 69 kV line that goes through town."*

On page 12, lines 6-14 he adds:

> *Q. PLEASE EXPLAIN THE CONCEPT OF DUPLICATION OF FACILITIES.*
> *A. While I am not an attorney, I understand that one reason the Minnesota Legislature has established exclusive service territories in Minnesota is to avoid the duplication of utility infrastructure.*
>
> *Q. DOES SLAYTON'S PLAN RESULT IN THE DUPLICATION OF FACILITIES?*
> *A. Yes. Slayton is currently served by an Xcel Energy transmission line and distribution substation, and it appears that the City intends to duplicate these facilities from Great River Energy and Nobles, respectively."*

Based on my understanding of the plans in the area regarding the 69-kV transmission, Mr. Krug has misrepresented what Great River Energy and Nobles are constructing and how the system will operate.

Q. What is your understanding of the pending arrangement in the Slayton area?

A. The existing system consists of an Xcel owned 69-kV transmission line that provides service to the Xcel owned Slayton substation. Approximately 0.4 miles straight east of the Slayton substation is an older Nobles substation that also receives service from the same Xcel 69-kV transmission line. Noble has built a new substation approximately 0.2 miles south of the existing Xcel 69-kV line. This new substation will replace the older Nobles substation I referenced above. This new Nobles substation will also provide service to Slayton if the pending transaction goes forth as planned. Great River Energy is building some additional 69-kV transmission, but not as a replacement for the Xcel 69-kV line. It is an approximately 0.2 miles *extension* of the existing Xcel 69-kV line to bring transmission service to the new substation. Power for the new Nobles substation will still flow over the Xcel 69-kV line into the Great River Energy short transmission extension to the new substation. The new transmission planned by Great River Energy is not a duplication of the Xcel transmission line, it is an extension of it.

Q. What is your view of the new Nobles substation as viewed as a duplication of the existing Xcel substation?

A. The primary intent of Nobles construction of the new substation, as I understand it, is to replace its older existing substation, which would have needed to occur regardless of Slayton's creation of a municipal electric utility. If Slayton ultimately also receives service from this substation, I have included adequate compensation to Xcel for the "stranded" substation capacity in my loss of revenue payment as described in my direct testimony and expanded on above in my rebuttal of Ms. Peterson's direct testimony.

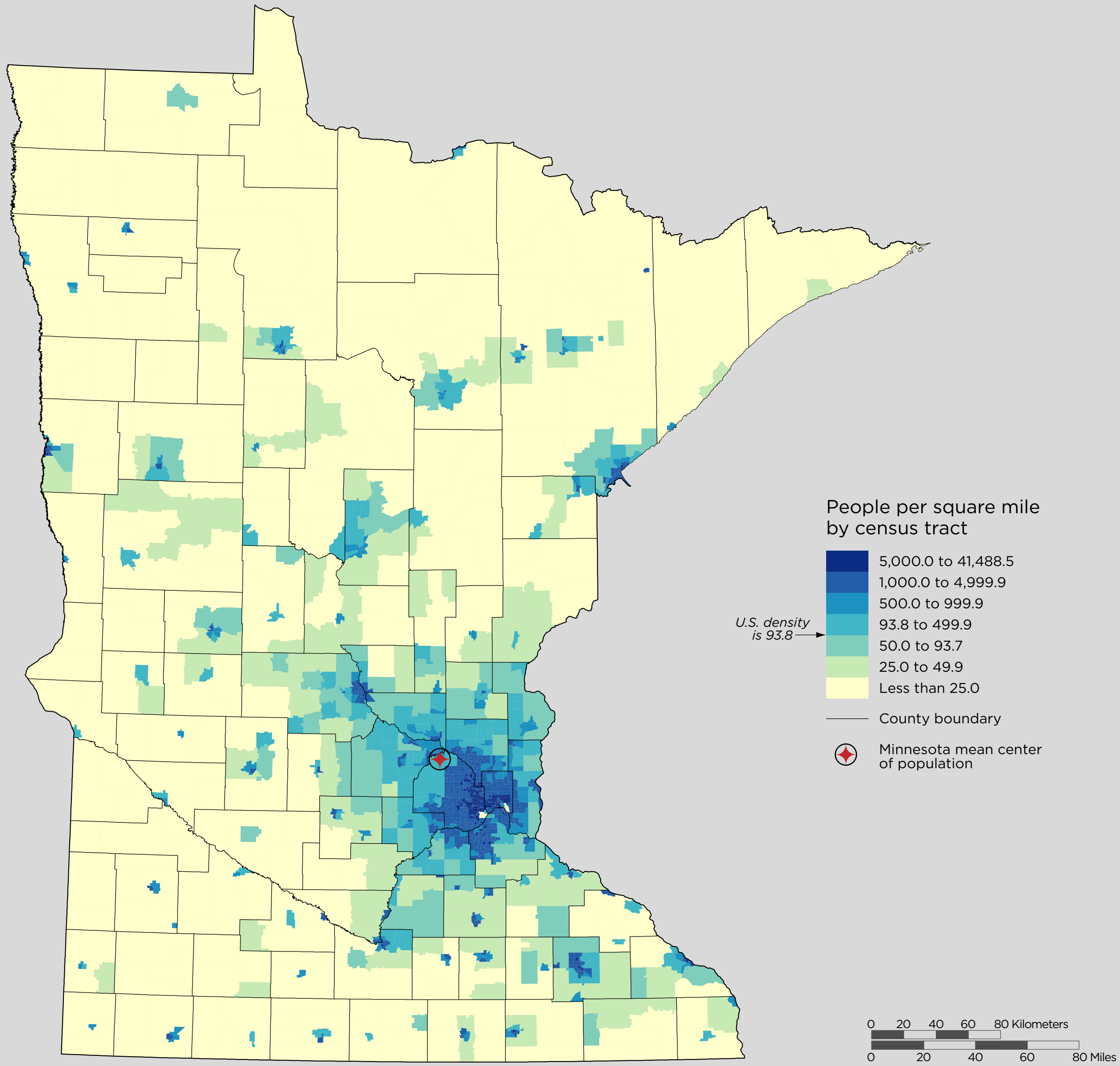
Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

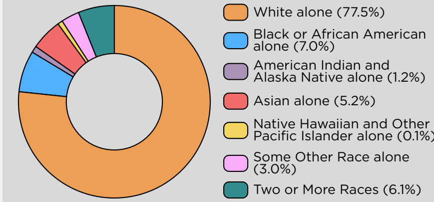
Attachment Description	**Pages**
Attachment G: Census Data for State of Minnesota 2020 (p. 6)	1
Attachment H: Census Data for Murray County Minnesota 2020 (p. 6)	1
Attachment I: Census Data for Slayton City Minnesota (p. 6)	6
Attachment J: Patrick T. Ortiz, The Electric Utility Industry Restructuring Act of 1999: Early Steps Toward Implementation, Natural Resources, Energy & Environmental Law Section of the State Bar of New Mexico (Winter 2000)	7
Attachment K: Cover Letter from Amy Liberkowski to Will Seuffert, Excerpted from Xcel's Application for Authority to Increase Electric Rates in Minnesota, dated Nov. 1, 2024, in Docket No E002/GR-24-320	5
Xcel Electric Response to Slayton Information Request No. 81 (p. 5)	1

2020 Census: Minnesota Profile

Population Density by Census Tract



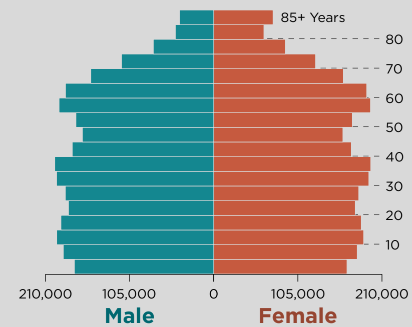
Race Breakdown



Hispanic or Latino (of any race) makes up **6.1%** of the state population.

Population by Sex and Age

Total Population: 5,706,494

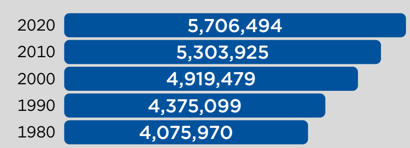


Housing Units

Total housing units:	**2,485,558**
Percent occupied:	90.7%
Owner occupied:	*70.6%*
Renter occupied:	*29.4%*
Percent vacant:	9.3%

Historical Population Totals

1980 to 2020



United States® Census Bureau | U.S. Department of Commerce U.S. CENSUS BUREAU *census.gov*

Source: 2020 Census Demographic and Housing Characteristics File (DHC), 1980 to 2020 decennial censuses

Attachment G
Page 1 of 1

QuickFacts

Murray County, Minnesota; United States

QuickFacts provides statistics for all states and counties. Also for cities and towns with a ***population of 5,000 or more***.

Enter state, county, city, town, or zip code -- Select a fact --

CLEAR TABLE MAP

View Selected Locations | Murray County, Minnesota | United

Table

Population	Murray County, Minnesota	United States
Population estimates, July 1, 2024, (V2024)	**8,044**	**340,110,988**
PEOPLE		
Population		
Population estimates, July 1, 2024, (V2024)	**8,044**	**340,110,988**
Population estimates base, April 1, 2020, (V2024)	8,168	331,515,736
Population, percent change - April 1, 2020 (estimates base) to July 1, 2024, (V2024)	-1.5%	2.6%
Population, Census, April 1, 2020	8,179	331,449,281
Population, Census, April 1, 2010	8,725	308,745,538

About datasets used in this table

Value Notes

Methodology differences may exist between data sources, and so estimates from different sources are not comparable.

Some estimates presented here come from sample data, and thus have sampling errors that may render some apparent differences between geographies statistically indistinguishable. Click the Quick Info icon to the left of each learn about sampling error.

The vintage year (e.g., V2024) refers to the final year of the series (2020 thru 2024). Different vintage years of estimates are not comparable.

Users should exercise caution when comparing 2019-2023 ACS 5-year estimates to other ACS estimates. For more information, please visit the 2023 5-year ACS Comparison Guidance page.

Fact Notes

- **(a)** Includes persons reporting only one race
- **(b)** Hispanics may be of any race, so also are included in applicable race categories
- **(c)** Economic Census - Puerto Rico data are not comparable to U.S. Economic Census data

Value Flags

- **D** Suppressed to avoid disclosure of confidential information
- **F** Fewer than 25 firms
- **FN** Footnote on this item in place of data
- **NA** Not available
- **S** Suppressed; does not meet publication standards
- **X** Not applicable
- **Z** Value greater than zero but less than half unit of measure shown
- **-** Either no or too few sample observations were available to compute an estimate, or a ratio of medians cannot be calculated because one or both of the median estimates falls in the lowest or upper interval of a
- **N** Data for this geographic area cannot be displayed because the number of sample cases is too small.

QuickFacts data are derived from: Population Estimates, American Community Survey, Census of Population and Housing, Current Population Survey, Small Area Health Insurance Estimates, Small Area Income and Poverty Est Housing Unit Estimates, County Business Patterns, Nonemployer Statistics, Economic Census, Survey of Business Owners, Building Permits.

Place

Slayton city, Minnesota

Slayton city, Minnesota is a city, town, place equivalent, or township located in Minnesota. Slayton city, Minnesota has a land area of 2.0 square miles.

// United States / Minnesota / Slayton city, Minnesota

ON Display Sources

Populations and People
Total Population
2,013
P1 | 2020 Decennial Census

Income and Poverty
Median Household Income
$65,724
S1901 | 2023 American Community Survey 5-Year Estimates

Education
Bachelor's Degree or Higher
31.4%
S1501 | 2023 American Community Survey 5-Year Estimates

Employment
Employment Rate
61.5%
DP03 | 2023 American Community Survey 5-Year Estimates

Housing
Total Housing Units
1,047
B25002 | 2023 American Community Survey 5-Year Estimates

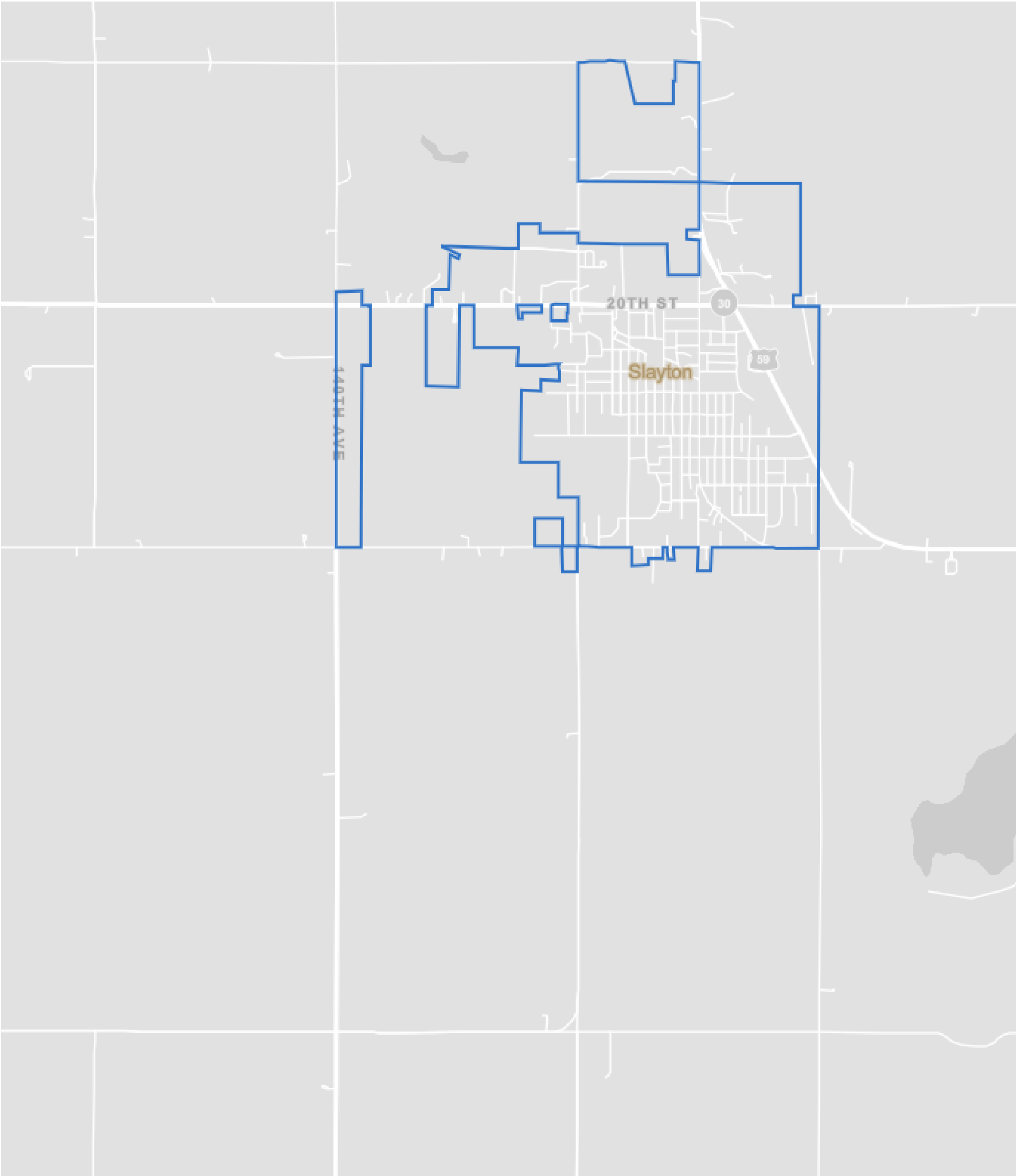
Health
Without Health Care Coverage
5.6%
S2701 | 2023 American Community Survey 5-Year Estimates

Families and Living Arrangements
Total Households
923
DP02 | 2023 American Community Survey 5-Year Estimates

Race and Ethnicity
Hispanic or Latino (of any race)
85
P9 | 2020 Decennial Census

Attachment I
Page 1 of 6

Slayton city, Minnesota Reference Map



Source: U.S. Census Bureau

Populations and People

Age and Sex

39.0 ± 4.8
Median Age in Slayton city, Minnesota

39.2 ± 0.1
Median Age in Minnesota

S0101 | *2023 American Community Survey 5-Year Estimates*

Population Pyramid: Population by Age and Sex
in Slayton city, Minnesota

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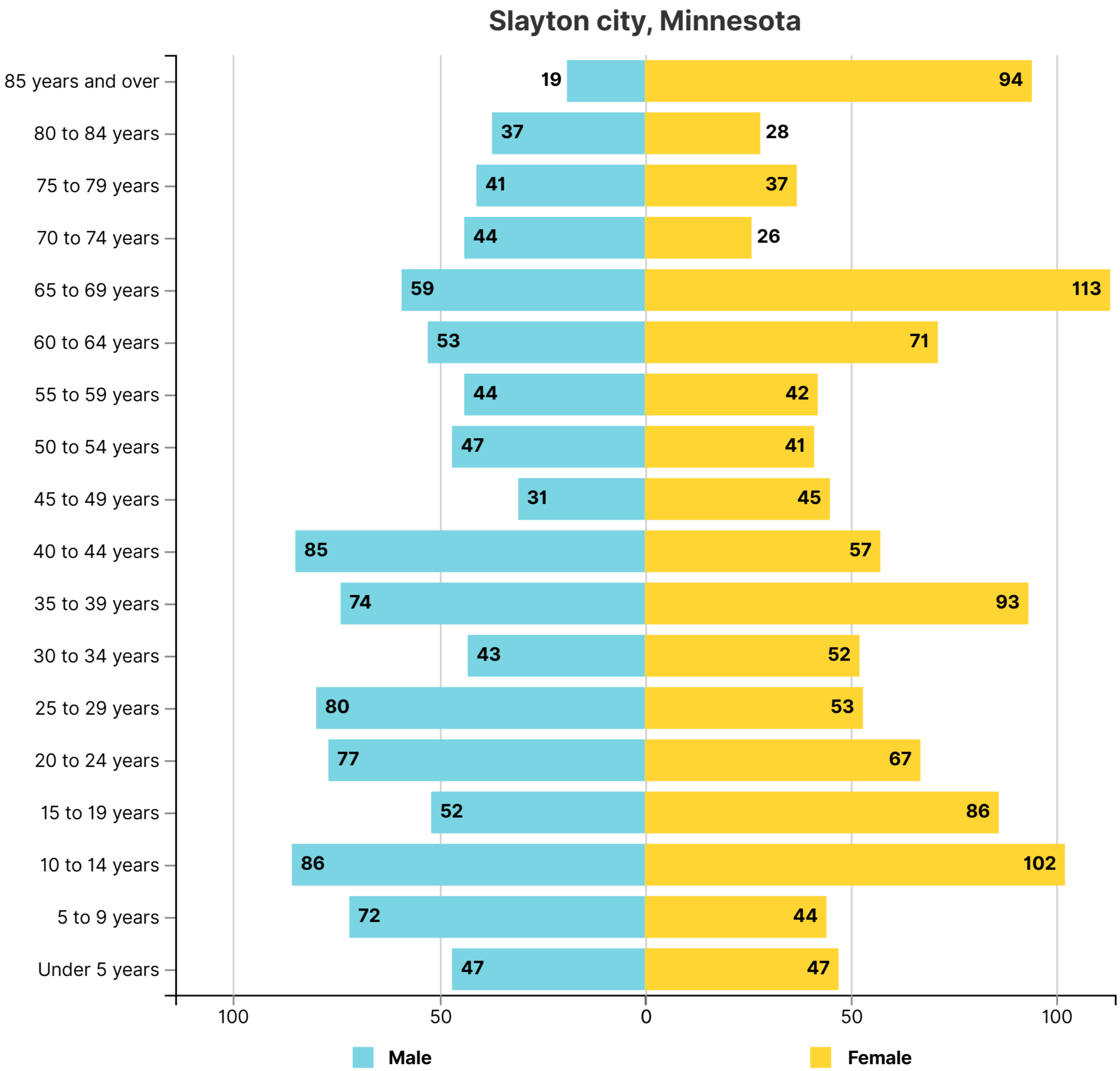

Display Margin of Error
S0101 | *2023 ACS 5-Year Estimates Subject Tables*

Language Spoken at Home

Attachment I
Page 3 of 6

5.0% ± 3.6%
Language Other Than English Spoken at Home in Slayton city, Minnesota

13.1% ± 0.3%
Language Other Than English Spoken at Home in Minnesota

S1601 | 2023 American Community Survey 5-Year Estimates

Types of Language Spoken at Home
in Slayton city, Minnesota

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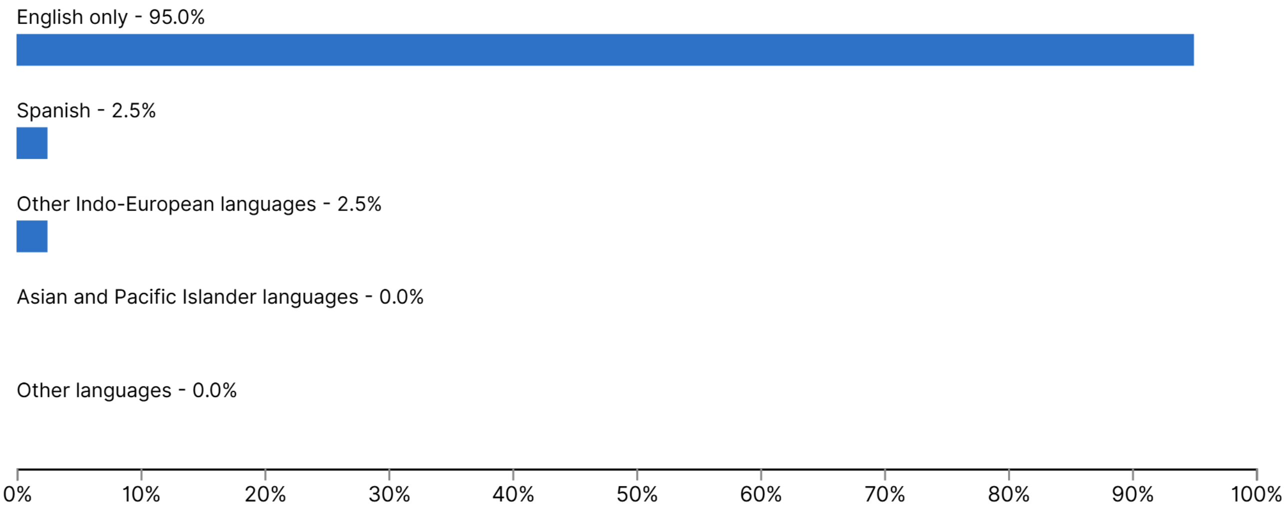

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S1601 | 2023 American Community Survey 5-Year Estimates

Native and Foreign-Born

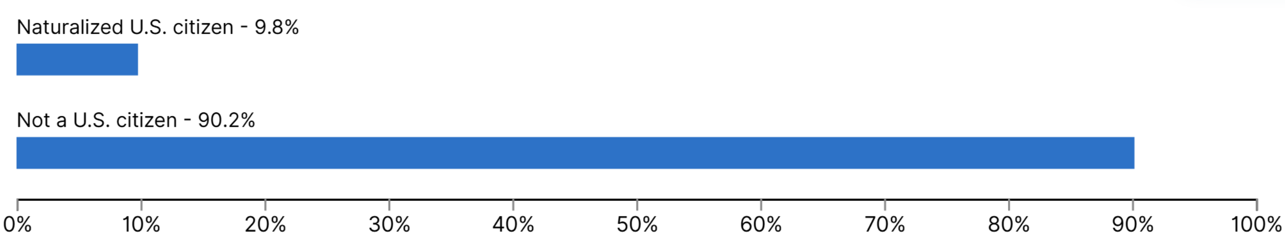
2.0% ± 1.6%
Foreign-Born population in Slayton city, Minnesota

9.0% ± 0.2%
Foreign-Born population in Minnesota

DP02 | 2023 American Community Survey 5-Year Estimates

Foreign-Born Population
in Slayton city, Minnesota

Share / Embed



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DP02 | 2023 American Community Survey 5-Year Estimates

Older Population

23.8% ± 3.6%
65 Years and Older in Slayton city, Minnesota

18.2% ± 0.1%
65 Years and Older in Minnesota

DP05 | 2023 American Community Survey 5-Year Estimates

Older Population by Age
in Slayton city, Minnesota

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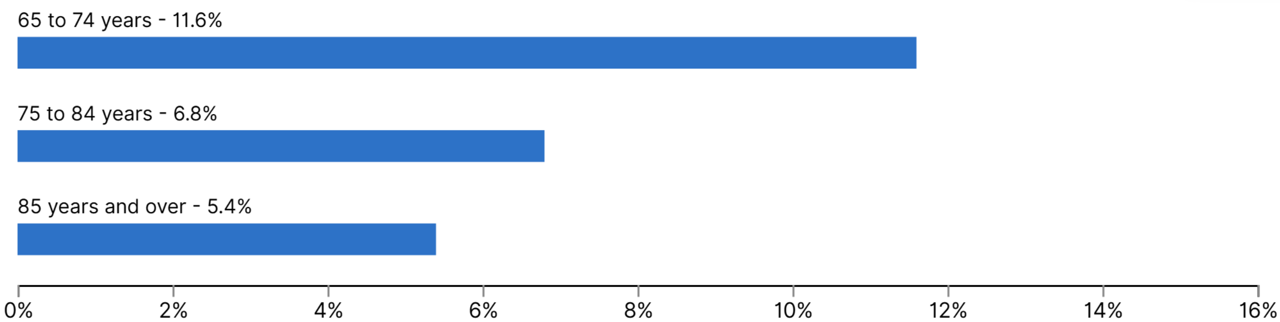

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DP05 | 2023 American Community Survey 5-Year Estimates

Residential Mobility

2.8% ± 2.0%
Moved From a Different State in the Last Year in Slayton city, Minnesota

1.8% ± 0.1%
Moved From a Different State in the Last Year in Minnesota

S0701 | 2023 American Community Survey 5-Year Estimates

Residential Mobility in the Last Year

in Slayton city, Minnesota

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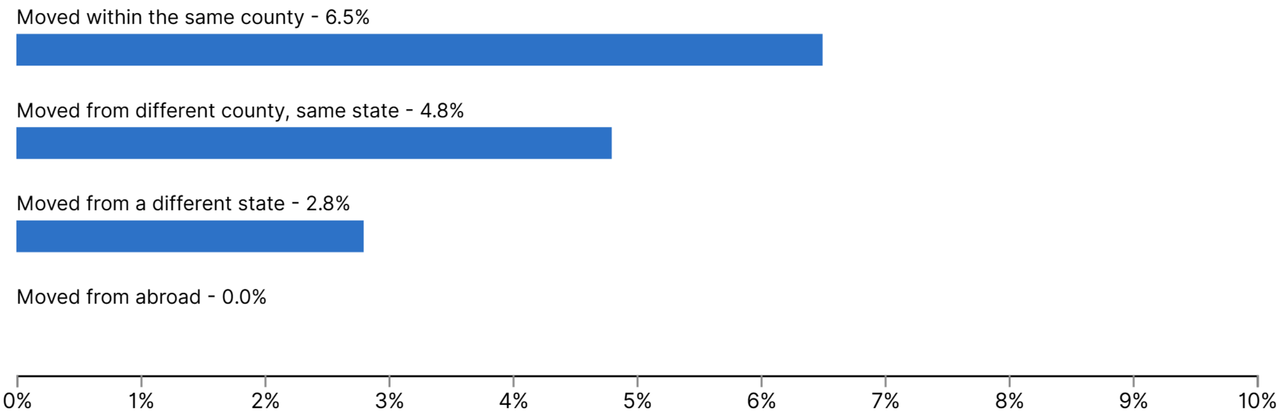

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S0701 | *2023 American Community Survey 5-Year Estimates*

Veterans

5.4% ± 1.8%

Veterans in Slayton city, Minnesota

5.5% ± 0.1%

Veterans in Minnesota

S2101 | *2023 American Community Survey 5-Year Estimates*

Veterans by Sex

in Slayton city, Minnesota

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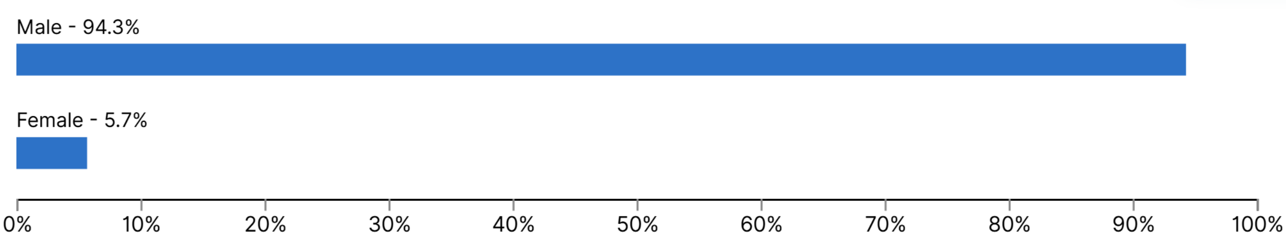

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S2101 | *2023 American Community Survey 5-Year Estimates*

NATURAL RESOURCES, ENERGY & ENVIRONMENTAL LAW SECTION of the State Bar of New Mexico

WINTER 2000

THE ELECTRIC UTILITY INDUSTRY RESTRUCTURING ACT OF 1999:

EARLY STEPS TOWARD IMPLEMENTATION

By Patrick T. Ortiz - Senior Vice President, General Counsel and Secretary

On April 8, 1999, the Governor signed into law a landmark piece of legislation. The Electric Utility Industry Restructuring Act of 1999 provides for the orderly transition from a regulated monopoly structure to a competitive marketplace for retail sales of electricity. Codified at N.M. Stat. Anno., §§ 62-3A-1 to 23, the Restructuring Act provides a comprehensive framework for this transition, although much remains to be done to flesh out the overall structure. The Legislature leaves this to the Public Regulation Commission, within the guidelines established in the Restructuring Act.

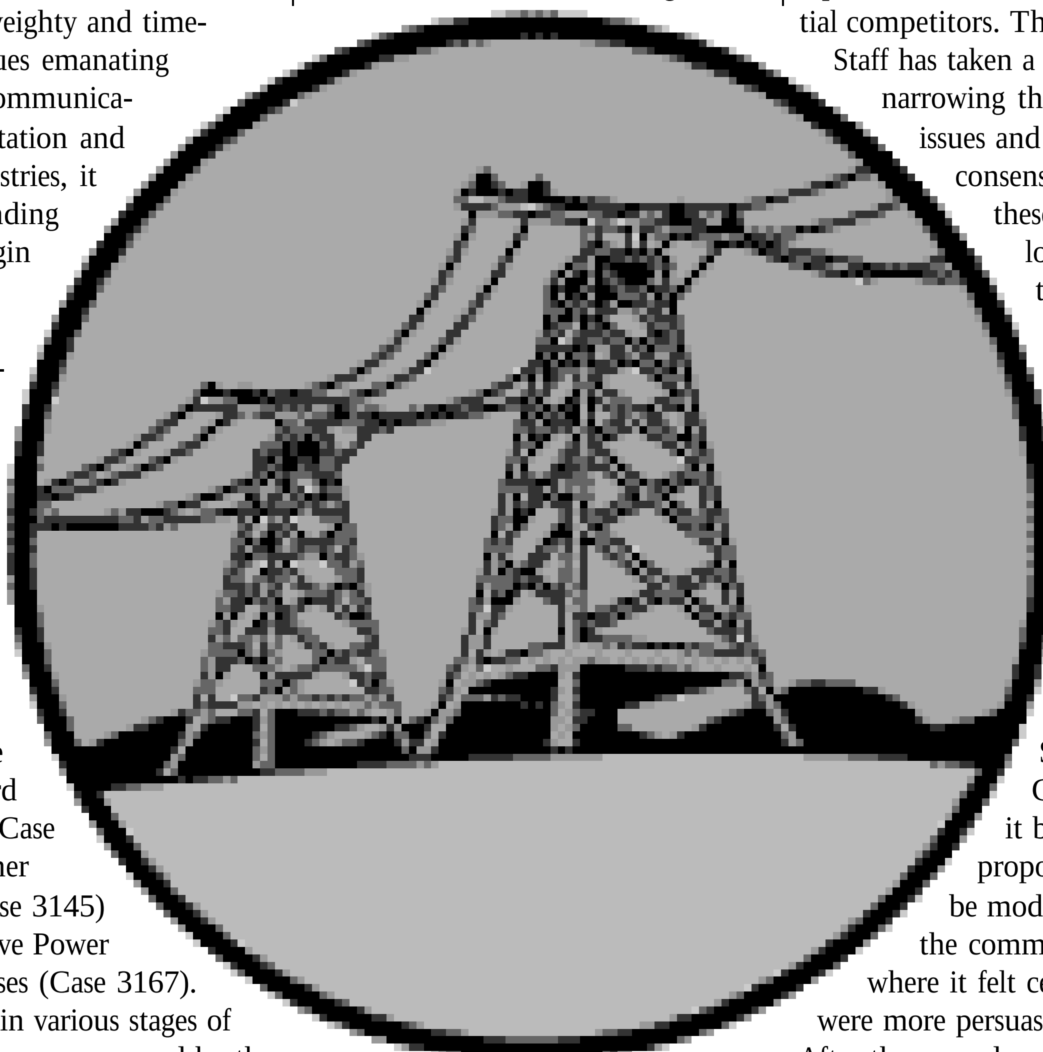
Retail electric service can be classified into three basic components: generation (or more broadly, power supply), transmission and distribution. The Restructuring Act makes power supply competitive and deregulates it, subject to residual regulation around customer protections. Transmission and distribution remain regulated monopolies. In order to facilitate the competitive marketplace in power supply, transmission and distribution systems are required to provide access for all customers and power suppliers so that customers are able to choose from whom they wish to buy their electricity and have it delivered over the lines of the utility company, essentially a common carrier function. In order to avoid discriminatory conduct favoring its own power supplies over those of competitors, the Restructuring Act requires utilities to separate their regulated businesses from their competitive businesses into at least two separate corporations prior to the scheduled start date of customer choice, or open access. In turn, behavioral rules (called "Code of Conduct") are required to govern the relationships and conduct of the utilities to all other suppliers. Unless the Commission finds

continued on page 2

that more time is needed in order to properly implement restructuring, in which case the Commission can extend dates up to one year, all orders must be in place by December 1, 2000, so as to allow customer choice for residential, small business and educational institution customers on January 1, 2001.

Although the Commission is burdened by weighty and time-consuming issues emanating from the telecommunications, transportation and insurance industries, it is somehow finding the time to begin the process of implementing the Restructuring Act. Currently, it has issued notices of proposed rulemakings on four critical subjects: Code of Conduct (Case 3106), Standard Offer Service (Case 3109), Customer Protection (Case 3145) and Competitive Power Supplier Licenses (Case 3167). These case are in various stages of the rulemaking processes used by the Commission to obtain public comment on proposed rules. This article will focus on the Code of Conduct rulemaking.

The Restructuring Act prohibits the utility company, i.e. the company that owns the wires that delivers electricity, from discriminating against any competitive power supplier. All competitors must be treated fairly by the utility company and have equal opportunity to have access to the transmission and distribution system and to customer and network information. The utility company is prohibited from providing more favorable treatment to its competitive affiliate than it would to non-affiliated competitors. In addition, the Restructuring Act



prohibits cross-subsidies between the utility and its affiliates. The Act specifically requires a code of conduct for each utility to assure compliance with these general mandates. Case 3106 is the Commission's proceeding to adopt the rules necessary to implement these provisions of the Act.

The Commission has received two rounds of written comments on its proposed Code of Conduct rules and has conducted a hearing to receive oral comments from the public. The Commission has left the record open to receive additional written comments until December 6, 1999. Parties filing comments included customers, customer representatives, utilities, and potential competitors. The Commission Staff has taken a leadership role in narrowing the controversial issues and driving towards consensus on what these rules should look like. Initially, the Staff parsed through the first round of written comments and provided an analysis of those comments in its own second round of comments. The Staff advised the Commission how it believed the proposed rules should be modified based on the comments, suggesting where it felt certain arguments were more persuasive than others. After the second round of comments, Staff sponsored a workshop for all parties to discuss proposed changes to suggest to the Commission. The workshop resulted in further consensus, greatly assisting the Commission in being able to zero in on the areas of disagreement.

Even though open access is not supposed to start until January 1, 2001, at the earliest, and much preparation is underway to properly implement it according to the Restructuring Act, New Mexico is already experiencing the forces of competition. Customers want to be able to start shopping so they will have power supplies lined up when the market actually “opens”. Potential suppliers want to be able to talk to customers so they will have their deals in place as well. The Restructuring Act allows for the broadest customer choice, allowing the incumbent utility to separate its power supply assets into a separate corporation and compete fairly. But no one is allowed to offer competitive power supplies for retail sale in New Mexico without a license. As customers began to explore their options, the question arose as to whether or not a public utility which had not separated its functions could be granted a competitive power supplier license. The process for separation could take many months thus inhibiting the incumbent power supplier from being a choice for customers contrary to the intent of the Act. But there was a concern with allowing the utility to offer competitive power supplies prior to separation because of the potential anti-competitive conduct or the appearance of favoritism. The proposal to the Commission that appears to have widespread support is for a transitional provision that allows a utility to get the license on a temporary basis pending separation with the requirement that the Code of Conduct applies. Effectively, that requires the utility to do internal separations, not unlike what has been required by federal law on the wholesale side, that reflects the legal separation to come.

The Act prohibits “unfair competitive advantages”, not all competitive advantages. As a result, it is appropriate to allow the utility and its competitive affiliates to take advantage of legitimate economies of scale and scope, which also inures to the benefit of customers in the form of reduced prices, both on the regulated side and on the unregulated side. Otherwise, incumbent power suppliers are placed at an unfair competitive disadvantage that could impose an artificial pricing umbrella protecting inefficient power suppliers by driving prices higher than they would otherwise be under an efficient market system.

The initial proposed rules would have prohibited the sharing of telecommunications, computer and information systems between the utility and affiliates. The purpose behind the specific prohibition was to comply with the Act’s prohibition against sharing of information that would give an affiliate an unfair competitive advantage. But the practicalities of the situation are that such a flat-out ban went too far with the possibility of adverse, unintended consequences, when less drastic regulations are sufficient to achieve the intended purpose. As the rulemaking process progressed, support coalesced around a requirement that information systems contain firewalls, password requirements and other security measures designed to achieve the confidentiality required by the Act.

It has been about seven months since the Restructuring Act became law. Much has been done in preparation for its implementation, but much, much more remains to be done. The Code of Conduct rulemaking is a cornerstone of the structure being put in place. Either late this year or early next year, the Commission will adopt final rules for this critical piece of the puzzle. It is also proceeding with other rulemakings. March 1, 2000, is a critical date. That is the deadline for utilities to file their transition plans which will lay out specific proposals for implementing the Act and the rules. In order to try and simplify the process, PNM has filed the separation plan component of the transition plan early in hopes that such a process will facilitate Commission decision-making and timely implementation of customer choice. There’s a long road ahead. It should prove to be an exciting and challenging journey.

CONSUMPTIVE USE:

Statutorily Undefined But an OSE Standard

By Jeffrey H. Albright, Eastham, Johnson, Monnheimer & Jontz, P.C.

Consumptive use is not defined in New Mexico statutes. Statutory references are made to consumptive use of water only in our interstate compacts. Nonetheless, it is central to water rights administration and is determined by the Office of the State Engineer (OSE) using complex factors. State Engineer Technical Report No. 32 (Blaney and Hanson, 1965) defines consumptive use as "The unit amount of water used on a given area in transportation, building of plant tissue, and evaporation from adjacent soil, water surface, snow, or intercepted precipitation in a specified time." The amount of consumptive use varies with, among other things, temperature, length of day, and available moisture, (e.g., both humidity and rainfall) in a given location.

Simply stated, consumptive use is the amount of water actually consumed or used. It is always less than the diverted amount. Only the consumptive use amount can be transferred to a different location or purpose of use. For example, in the Belen area of the Middle Rio Grande, for every 3.0 acre-feet of diversion (every acre of irrigated land), the consumptive use is 2.1 acre-feet per acre. Many other areas of the sate are considerably less. If approved by the OSE, only the amount of consumptive use calculated on the total acre feet requested will be available to move to another location.

DRAFT MINUTES OF THE BOARD OF DIRECTORS MEETING OF THE SECTION OF NATURAL RESOURCES, ENERGY AND ENVIRONMENTAL LAW

OCTOBER 22, 1999
THE SWEENY CENTER
SANTA FE, NEW MEXICO.

I. <u>INTRODUCTION OF BOARD MEMBERS, COMMITTEE CHAIRS, SECTION MEMBERS AND GUESTS.</u>

The Board meeting commenced at 5:30 P.M. In attendance were Steven L. Hernandez, Mike Cadigan, Greg Nibert, Tracy Hughes, Karen Fisher, and Lettie Belin. Also in attendance was Marte Lightstone. Steven L. Hernandez agreed to take minutes.

II. <u>APPROVAL OF MINUTES, July 30, 1999 MEETING.</u>

Minutes for the July 30, 1999 Meeting was approved.

III. <u>BUDGET REPORT.</u>

A. *CURRENT BUDGET STATUS.*

Mike Cadigan reported that he had checked into contributions from the section to the UNM Law Library. It had been several years since there was a contribution to purchase any resource-oriented materials. Steven L. Hernandez pointed out that there were some items on the current budget that would not utilize the full amounts budgeted. The Law Reporter, Lecture Series and Student Writing Paper Award would have about $2,000 left over. He asked that the board consider making a $2,000 contribution to the Albert E. Utton Natural Resources Award. The annual award goes to a third year law student who has demonstrated outstanding achievement in natural resources law.

B. *ALBERT E. UTTON AWARD.*

Upon motion duly made and seconded, the board authorized Steven L. Hernandez to make a $2,000 contribution to the Albert E. Utton Natural Resources Award in the name of the section. The funds are to come from the line items of the Law Reporter, Lecture Series and Miscellaneous-Sections as needed.

IV. <u>NOMINATING COMMITTEE REPORT.</u>

Steven L. Hernandez has agreed to be the incoming chair of the Section. Maria O'Brien will be asked to continue on as Budget Officer. If she declines, Marte Lightstone will consider taking the position.

continued on next page

V. CLE COMMITTEE REPORT.

The seminar on Environmental Law Update was well attended. We thank all of our section members that attended.

VI. NATIONAL SONREEL CONFERENCE IN SAN DIEGO.

Mike Cadigan reported that the ABA SONREEL section has changed its name to Section on Resource Law. No one felt a need to change our section's name to follow suit at this time.

VII. NEWSLETTER.

Section members are encouraged to submit articles. The newsletter is only as good as what the members provide. Kathy Blackett is the newsletter editor and you can submit your articles to her at P.O. Box 25687, Albuquerque, NM 87125. Ms. Blackett's fax number is 243-4408 and her telephone number is 842-1950 should you wish to fax your articles.

XII. OLD BUSINESS.

None.

XIII. NEW BUSINESS.

Steven L. Hernandez reported that the Section's Spring 2000 seminar on using the Internet in the various disciplines in the Section is proceeding forward. He has spoken to Steve Meilleur about combining the seminar with a hands on workshop on a Saturday at the Law School. He needs volunteers in each of the disciplines of the section to brainstorm some ideas about what agencies they deal with that could make a presentation. For example, the Office of the State Engineer, BLM, Bureau of Reclamation, Etc. Call Steve with any ideas at 505-526-2101 or fax at 526-2506.

He suggested we could get someone from the Department of Interior in Washington D.C. to come out and explain what information is available. The various state agencies in water, mining, oil and gas, etc. could also make presentations.

XIII. ADJOURNMENT.

5:45pm

Air Quality Regulation for the Natural Resources Industry

February 17 & 18
Salt Lake City, - Utah

Sponsored by
Rocky Mountain Mineral Law Foundation

12.9 General MCLE Credits

The Rocky Mountain Mineral Law Foundation is sponsoring a Special Institute on Air Quality Regulation, which will provide a comprehensive overview of the various programs under the Clean Air Act which directly or indirectly affect natural resources development.

Who should attend?
Attorneys, government regulators, and corporate managers with responsibility for air pollution issues as they affect the development of natural resources should attend this uniquely focused program.

For more information
(303) 321-8100

VISIT SONREEL ON THE WEB

Our Web page is up and running!

Visit us at
http://www.nmbar.org/membersonly/naturalresources/natresourceslaw.htm

NEW MEXICO SONREEL DIRECTORY

The New Mexico Section on Natural Resources, Energy and Environmental Law will publish a directory of attorneys practicing in the natural resources areas.

Please provide the following information for inclusion in the directory and fax (505-764-5480) or mail (PO Box 1276, Albuquerque, NM 87103-1276) to Jeffrey H. Albright or Ro Saavedra at Eastham Johnson Monnheimer & Jontz, P.C. no later than April 15, 2000.

CHECK THE FOLLOWING
AREAS OF PRACTICE

- ❑ Oil & Gas
- ❑ Energy
- ❑ Water
- ❑ Environmental Regulation & Compliance
- ❑ Environmental Tort
- ❑ Mining
- ❑ Other ______________________
  ____
  ____

Name: ____

Firm: ____

Mailing Address: ______________________________________

City, State, Zip Code: __________________________________

Business Phone: ________________ Home Phone: ________________

Fax: ________________ E-mail: ____________________

Northern States Power Company
Before the
Minnesota Public Utilities Commission

Application for Authority to
Increase Electric Rates in Minnesota
Docket No. E002/GR-24-320

November 1, 2024

Volume 1

Notice of Change in Rates
Interim Rate Petition

414 Nicollet Mall
Minneapolis, MN 55401

November 1, 2024

—Via Electronic Filing—

Will Seuffert
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: APPLICATION
AUTHORITY TO INCREASE ELECTRIC RATES
DOCKET NOS. E002/GR-24-320 & E002/M-24-321

Dear Mr. Seuffert:

Enclosed is the Application for a Proposed Increase in Electric Rates (Application) of Northern States Power Company, doing business as Xcel Energy (Xcel Energy or Company). This Application is being filed with the Minnesota Public Utilities Commission (Commission) pursuant to Minn. Stat. § 216B.16, subds. 1 and 19.

Xcel Energy seeks authority to increase electric rates, through a two-year multiyear rate plan (MYRP), to reflect the cost of providing service to our customers, including an appropriate return on common equity. The MYRP we propose ensures just and reasonable rates and will allow the Company to continue providing leadership on a number of key initiatives, including: (1) further transforming our generation fleet as we move forward to meet the "carbon-free by 2040" standard for Minnesota's electric utilities, including retiring thousands of megawatts of coal generation from our system in a span of about six years and working to extend the life of our nuclear facilities; (2) creating a more advanced distribution grid that continues to reliably serve our customers, while enabling further transformation of our overall energy delivery system and better meeting new customer expectations; and (3) assisting in continued beneficial electrification and the electrification of Minnesota's transportation system. The MYRP also enables the Company to continue improving the customer experience while maintaining safe and reliable energy service for our customers.

With our MYRP, we are requesting a net increase in gross revenues of $353.3 million (9.6 percent) in 2025, and an incremental $137.5 million (3.6 percent) in 2026, based on present revenues. The MYRP reflects a first year revenue requirement calculated based on a traditional test year (2025), and revenue requirements for the proposed plans year (2026) also reflecting a cost of service approach, as described in our Application.

We are also requesting that the Commission suspend our proposed rates, and authorize the recovery of interim rates effective January 1, 2025, as set forth in our Notice and Petition for Interim Rates (Petition). Our request is for a 2025 interim revenue increase equal to $223.8 million, or 6.1 percent, based on present revenues. We also request an incremental 2026 interim revenue increase equal to $138.8 million, or an incremental 3.7 percent, based on present revenues. The interim revenue request for 2025 will be uniformly billed as an 8.32 percent increase on the base rate portion of customers' bills (exclusive of fuel and purchased energy costs and certain rate riders) and for 2026 will be uniformly billed as an incremental 4.90 percent increase over 2025 on the base rate portion of customers' bills (exclusive of fuel and purchased energy costs and certain rate riders). The difference between the base rate and the overall bill percentage increases results primarily from the exclusion of fuel and purchased energy costs.

Typically, final rates would become effective within 10 months of the date of the Application, unless the review period is extended by the Commission. We recognize, however, that the statutory triggers for extension provided by Minn. Stat. § 216B.16 subds. 2 and 19 will apply to the schedule of our case.

A. Contents of Filing

Our Application for Proposed Increase in Electric Rates is presented in the following volumes:

Volume 1 (Application/Interim)	Notice of Change in Rates, Interim Rate Petition
Volumes 2A to 2E	Testimony and Supporting Schedules, Completeness List, Proposed Tariff Sheets
Volume 3	Required Information
Volume 4	MYRP Plan Workpapers
Volume 5	Budget Documentation

In addition to the documents listed above, included in Volume 1 is a proposed Notice to be provided to each municipality and county in Xcel Energy's electric service territory named on the attached mailing list. Also included in Volume 1 is the Notice and Petition for Interim Rates (Interim Rate Petition) that describes the interim rate schedules for each customer class and contains proposed customer notices if the Commission elects to suspend the requested final rate increase. Once the notices are approved and the interim rate increase is determined by the Commission, these notices will be provided to the municipalities, counties, and customers.

B. Request for Protection of Non-Public Information

The Company recognizes and supports the need for transparency in review of our Application. Non-Public data included in this filing is limited to certain portions of the Testimony, schedules, and workpapers. Highly confidential information is being provided in Docket No. E002/M-24-321. Attachment A to the Notice of Change in Rates identifies the specific models, reports, expenses, sales and pricing data and other materials identified as Non-Public data in the filing that we believe qualify as trade secret data pursuant to Minn. Stat. § 13.37, subd. 1(b). These models, reports, and expense, sales and pricing data and other materials have important economic value to the Company or third-party vendors with whom the Company works as a result of their not being public, and the Company takes efforts to prevent their public disclosure. The Company has identified the Trade Secret and other Non-Public information pursuant to Minn. Rule 7829.0500.

C. Service and Summary of Filing

A copy of the Application has been served on the Minnesota Department of Commerce, Division of Energy Resources, and the Office of Attorney General – Antitrust and Utilities Division. A copy of the Application, including a Summary of Filing, has also been served on the service list for this docket, for the Company's most recent electric rate case (Docket No. E002/GR-21-630), and all persons on the Company's electric general service list as shown on the attached Affidavit of Service.

Xcel Energy will fully cooperate with the Commission, the state agencies and stakeholders as they review the Application, including the Interim Rate Petition. Please feel free to direct any questions regarding the Application to Amy Liberkowski at (612) 330-6613.

Sincerely,

Amy Liberkowski

AMY LIBERKOWSKI
REGIONAL V.P., REGULATORY AND PRICING
NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION

Enclosures
cc: Service Lists

☐ **Not-Public Document – Not For Public Disclosure**
☐ **Public Document – Not-Public Data Has Been Excised**
☒ **Public Document**

Xcel Energy		Information Request No.	81
Docket No.:	E002,PT7157/SA-25-129		
Response To:	City of Slayton		
Requestor:	Lisa Larson		
Date Received:	November 26, 2025		

Question:
Reference: N/A

Please provide a 10 year history of the total kWh sales in Slayton on an annual basis.

Response:
Table 1 below shows the kWh sales for customers in the City of Slayton for 2015 through 2024.

Table 1

Year	kWh
2015	20,734,760
2016	20,177,846
2017	20,511,720
2018	21,760,425
2019	21,439,197
2020	21,019,034
2021	20,591,706
2022	21,102,190
2023	20,887,637
2024	19,614,508

Preparer:	Lisa R. Peterson
Title:	Director, Regulatory Pricing and Analysis
Department:	NSPM Regulatory
Telephone:	612-330-7681
Date:	December 9, 2025