Direct Testimony and Schedules
Richard R. Schrubbe

Before the Minnesota Public Utilities Commission
State of Minnesota

In the Matter of the Application of Northern States Power Company
for Authority to Increase Rates for Gas Service in Minnesota

Docket No. G002/GR-23-413
Exhibit___(RRS-1)

Pension and Benefits Expense

November 1, 2023

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Schedules

Terms and Acronyms

ACM	Aggregate Cost Method
Commission	Minnesota Public Utilities Commission
Company	Northern States Power Company – Minnesota
EEI	Edison Electric Institute
ERISA	Employee Retirement Income Security Act
EROA	Expected Return on Assets
FAS	Statement of Financial Accounting Standard
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
IBNR	Incurred But Not Reported
IRC	Internal Revenue Code
LTD	Long-Term Disability
NSPM	Northern States Power Company – Minnesota
NSPW	Northern States Power Company - Wisconsin
PBGC	Pension Benefit Guaranty Corporation
PBO	Pension Benefit Obligation
Public Service	Public Service Company of Colorado
PVFB	Present Value of Future Benefits
SPS	Southwestern Public Service Company
WACC	Weighted Average Cost of Capital
Xcel Energy	Xcel Energy Inc.
XEPP	Xcel Energy Pension Plan
XES	Xcel Energy Services Inc.

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Richard Schrubbe. I am the Vice-President of Financial Analysis and Planning for Xcel Energy Services Inc. (XES), which provides services to Northern States Power Company – Minnesota (NSPM or the Company).

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. As Vice-President of Financial Analysis and Planning I am responsible for overseeing the business area leaders of Energy Supply, Transmission, Distribution, Gas Engineering & Operations, Nuclear, and Corporate Services with respect to budget planning, reporting, and analysis. I oversee the accounting for all employee benefits programs, playing a liaison role with the Human Resources department, external actuaries, and senior management with benefit fiduciary roles.I am also responsible for coordinating the benefits operations and maintenance (O&M), and capital budgeting and forecasting processes, as well as the monthly analysis of actual results against these budgets and forecasts. A summary of my qualifications, duties, and responsibilities is included as Exhibit___(RRS-1), Schedule 1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I discuss the pension benefits and other non-cash benefits the Company offers to its eligible employees and their families, and I present the costs of these benefits for the 2024 test year. In addition, I discuss pension cost accounting principles and explain how the Company's pension expense necessarily reflects the cumulative effect of pension asset gain and loss experiences.

I also support the Company's request to include the net rate base increase associated with its benefit costs. This net rate base increase reflects the increase associated with the prepaid pension asset, although that amount is reduced to some extent by the accrued liability costs associated with the retiree medical and post-employment benefit costs and the accumulated deferred income taxes (ADIT) associated with the prepaid pension asset. I provide a detailed discussion of the accounting and ratemaking treatment of these costs, and I demonstrate why this ratemaking treatment is reasonable.

Q. IS ANY OTHER COMPANY WITNESS ADDRESSING PENSION AND BENEFIT ISSUES?

A. Yes. Company witness Michael P. Deselich discusses the cash compensation offered by the Company, as well as the steps the Company has taken to help mitigate benefit cost increases.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. I present the remainder of my testimony in the following sections:

- Section II, *Pension and Benefits Overview*, provides a summary of the pension and benefit costs included in our test year.
- Section III, *Pension Cost Accounting*, discusses pension accounting principles and describes how the Company calculates its pension expense.
- Section IV, *Pension Assumptions*, presents the primary assumptions used to calculate our pension costs in this case.
- Section V, *Qualified Pension and 401(k) Match Costs*, quantifies the test year expense amounts for qualified pension and 401(k).

- Section VI, *Retiree Medical and FAS 112 Long-Term Disability Benefits*, presents information and costs related to our request for recovery of post-retirement healthcare and long-term disability benefits.
- Section VII, *Benefit Rate Base Assets and Liabilities*, discusses ratemaking treatment of both the Company's prepaid benefit costs and accrued liability costs.
- Section VIII, *Active Health and Welfare Costs*, provides details related to the active healthcare costs included in our rate request.
- Section IX, *Workers' Compensation FERC 925 Costs*, provides details related to the workers' compensation costs included in our rate request.
- Section X, *Conclusion*, summarizes the Company's request for recovery of pension and benefit-related costs.

II. PENSION AND BENEFITS OVERVIEW

Q. WHAT TYPES OF COSTS ARE INCLUDED IN THE COMPANY'S PENSION AND BENEFITS REQUEST?

A. With the exception of the workers' compensation costs discussed in Section IX of my testimony, all the Company's pension and benefits costs are recorded in FERC Account 926.

Q. TO PROVIDE CLARITY, PLEASE DESCRIBE HOW DOLLAR AMOUNTS IN YOUR TESTIMONY ARE PRESENTED.

A. Unless specifically indicated otherwise, all the dollar values presented in my testimony are presented at the State of Minnesota Gas Utility level.

Q. PLEASE PROVIDE A SUMMARY OF THE PENSION AND BENEFIT COSTS INCLUDED IN THE COMPANY'S RATE REQUEST.

A. Table 1 below sets forth the benefit amounts for the 2024 test year, as well as the actual amounts for 2022 and the forecasted amounts for 2023.

Table 1
Pension and Benefit Expense Summary ($)
FERC Account 926 Pension and Benefit Costs for NSPM Gas O&M, State of Minnesota

FERC 926 Benefit Type	2022 Actual Amounts	2023 Forecast	2024 Test Year
Actuarial Costs			
Qualified Pension	$2,139,260	$2,397,493	$2,269,317
FAS 106 Retiree Medical	447	195,790	225,398
FAS 112 LTD	(75,768)	(6,816)	11,612
Total Actuarial Costs	**2,063,939**	**2,586,465**	**2,506,327**
Health & Welfare			
Active Health Care	3,774,155	4,288,559	4,677,724
Misc Ben Programs, Life, LTD	383,309	471,827	500,895
Total Health & Welfare	**4,157,464**	**4,760,386**	**5,178,619**
Other Retirement			
401(k) Match	934,779	1,080,627	1,098,582
Deferred Comp Match	3,634	3,171	4,395
Ret. & Comp Consulting	41,414	35,217	38,092
Total Other Retirement	**979,827**	**1,119,015**	**1,141,069**
Total FERC 926	**7,201,230**	**8,465,866**	**8,826,015**

Q. IS THE COMPANY SEEKING TO RECOVER THE PENSION AND BENEFITS EXPENSE SHOWN IN TABLE 1?

A. Yes. Company witness Benjamin C. Halama has incorporated the test year amount in the cost of service he supports. As discussed in detail throughout my testimony, our forecasts of the pension and benefit costs included in FERC Account 926 are formulaic, are calculated in accordance with accounting rules and standards, and are based on actuarial assumptions specific to the Company.

III. PENSION COST ACCOUNTING

Q. WHAT TOPIC DO YOU DISCUSS IN THIS SECTION OF YOUR TESTIMONY?

A. In this section I discuss pension accounting principles and describe how the Company calculates its test year pension expense.

Q. IN ORDER TO ESTABLISH THE CONTEXT FOR YOUR DISCUSSION OF THE CALCULATION OF PENSION EXPENSE, PLEASE DESCRIBE THE QUALIFIED PENSION PLANS THE COMPANY OFFERS.

A. The Company has two qualified pension plans: the NSPM Plan and the XES Plan. Employees of NSPM are eligible to participate in the NSPM Plan, whereas employees of XES are eligible to participate in the XES Plan.

Q. ARE THE PENSION COSTS ATTRIBUTABLE TO EACH PLAN ACCOUNTED FOR IN THE SAME WAY?

A. No. Pension costs under the NSPM Plan are determined under the Aggregate Cost Method (ACM), whereas pension costs for the XES Plan are determined in accordance with Statement of Financial Accounting Standard (FAS) 87.[1] The history of the Company's use of these two different accounting methods is explained below, but the ultimate goal of both methods is the same – to provide an actuarially sound basis to calculate and recover over the course of an

[1] In 2009 FAS 87 was renamed Accounting Standards Codification 715-30, but I will continue to refer to the standard in this testimony as FAS 87 for ease of reference.

employee's career the amount of money that will be necessary to satisfy the Company's pension obligation to that employee. In effect, both methods allow the Company to reflect a current expense associated with a future liability.

A. The Nature of Pension Expense

Q. IS PENSION EXPENSE SIMPLY A CASH OUTLAY IN THE TEST YEAR, LIKE MANY OTHER COMPONENTS OF OPERATION AND MAINTENANCE EXPENSE?

A. No. Pension expense represents an accrual for a future liability rather than the cash to pay benefits in a given year. Thus, pension expense is more similar to our nuclear decommissioning accrual, which is an expense in our cost of service, than it is to, say, contractor expense for our vegetation management, which more closely represents cash that flows out the door in a given year.

Q. WHY IS THE DISTINCTION BETWEEN A PRESENT ACCRUAL AND A PRESENT CASH OUTLAY IMPORTANT?

A. A more current cash outlay, such as vegetation management (we still use accrual accounting for this cost), is not materially affected by a number of assumptions about longer-term future conditions, but only by timing differences in the billing for the costs. In contrast, the current accrual for a substantial and distant future liability is affected by both past events and future forecasts. We must know what happened in the past and must have a forecast of what will happen in the future in order to derive the most accurate measure of the current year expense associated with that future liability.

Q. WHY ARE PAST EVENTS TAKEN INTO CONSIDERATION FOR PURPOSES OF CALCULATING PENSION EXPENSE?

A. A fundamental component of pension expense is the experience from prior years. That is, the current year's pension expense is determined by knowing the existing value of the assets in the trust, as well as the forecasted future liability. To the extent the existing value of the assets is higher than initially forecasted, the level of expense is reduced, as there is less future cost to be recognized in the current period. To the extent the existing value of the assets is lower than initially forecast, then the expense level is higher.

Q. WHAT IS THE PROCESS FOR TAKING THE PAST EVENTS INTO ACCOUNT?

A. The elements used to calculate pension costs are established at the beginning of each year based on actuarial studies that account for factors such as the expected salary increases, expected mortality rates, the Expected Return on Assets (EROA), the discount rate and other factors. At the end of the year, the assumptions are trued up to actual experience, and the differences give rise to gains or losses.

Q. WHY IS IT NECESSARY TO TRUE-UP THE PROJECTIONS TO ACTUAL EXPERIENCE?

A. The Company makes projections so that it can reflect the most accurate forward-looking level of pension expense on its income statement. For example, our projection of future pension liability is based on our best estimate of how long employees will stay with the Company because pension benefits are designed to grow with years of service. But circumstances change over the course of a year, and the assumptions we made at the beginning of the year may have changed. To make our pension expense projections for the following year as accurate as possible, we incorporate the differences between the projections and actual experience from the prior years in our calculation of annual pension expense.

Q. WHAT DO YOU MEAN WHEN YOU SAY THAT THE COMPANY ACCOUNTS FOR THE CHANGES THAT HAVE OCCURRED?

A. Pension accounting systematically tracks the differences between the Year 1 forecast assumptions and the Year 1 actual experience, and then it includes a portion of that difference into the Year 2 pension expense as a gain or loss. (I explain in the next part of my testimony why only a portion is incorporated into the Year 2 pension expense calculation.) Deviations that reduce the level of the Present Value of Future Benefits (PVFB) are gains. Deviations that increase the PVFB are losses. The treatment of cumulative gain and loss experiences is a key component of the annual pension expense calculation, as I will discuss in the next subsection of my testimony.

B. Treatment of Gain and Loss Experiences

Q. WHAT FOUNDATIONAL CONCEPTS ARE NECESSARY TO UNDERSTAND HOW GAIN AND LOSS EXPERIENCES ARE INCORPORATED INTO THE CALCULATION OF CURRENT PENSION EXPENSE?

A. There are three foundational concepts which I will explain in turn in detail. By way of introducing those concepts:

- The first concept is that asset gains and losses must be distinguished from liability gains and losses.
- The second concept involves the phase-in of asset gains and losses into an amortization "pool."
- The third concept involves amortization of FAS 87 asset and liability gains and losses once they are phased in.

Q. STARTING WITH THE FIRST CONCEPT YOU MENTIONED, PLEASE EXPLAIN THE DISTINCTION BETWEEN ACTUARIAL ASSET GAINS AND LOSSES AND LIABILITY GAINS AND LOSSES.

A. The dollars in the pension trust are invested in assets such as stocks, bonds, real estate, and commodities, among other things. Each year the Company forecasts the average return that those assets will produce in that year, which is referred to as the expected return on assets, or EROA. Actuarial asset gains or losses arise when the actual returns on the pension trust assets in a given year are greater than or lesser than the expected return on assets. Suppose, for example, that the plan expects a seven percent return on its pension trust assets, which total $1 billion. The expected return for that year would be $70 million. If the actual return in that year is nine percent, the plan will have returns of $90 million, and the asset gain will be $20 million. Of course, the opposite can also occur. If the expected return is seven percent and the actual return on the assets is five percent, the plan has a return of only $50 million and therefore suffers a $20 million asset loss.[2] This actuarial loss then increases the amount the Company must set aside to satisfy future pension liabilities, as compared to earlier forecasts.

The plan must also account for factors that affect the PVFB, such as the discount rate, the expected number of retirements, and wage increases. Actuarial liability gains and losses arise when those components of pension expense differ from expectations. For example, if the Company assumes a four percent discount rate at the beginning of the year but the actual discount rate measured

[2] It is important to distinguish between an actual loss and an actuarial loss. The $20 million asset loss discussed in the text does not represent an actual loss in the value of the trust. To the contrary, the trust has gained $50 million in return under this example. But because the $50 million of actual return is less than the $70 million of expected return, it is considered a $20 million actuarial loss.

at year end for the next year turns out to be five percent, the Company will have a liability gain because the higher discount rate reduces the amount the Company must set aside to satisfy future pension liabilities.

Q. WHEN THE COMPANY HAS ASSET GAINS OR LIABILITY GAINS, DOES IT WITHDRAW THOSE AMOUNTS FROM THE TRUST AND TREAT THEM AS EARNINGS?

A. No. Federal law requires that all the gains and losses stay within the pension trusts, which means that they affect the amount of pension expense in subsequent years.[3] Generally speaking, if there is an asset or liability gain, it reduces the Company's pension expense in the following years. If there is an asset or liability loss, it increases pension expense in the following years. Thus, the Company treats gains and losses symmetrically in the sense that both must remain in the pension trust and both affect future pension expense.

Q. IS THIS DISTINCTION BETWEEN ASSET GAINS AND LOSSES AND LIABILITY GAINS AND LOSSES IMPORTANT?

A. Yes. The distinction is important because the asset gains and losses are phased in over time, which is the second fundamental concept I note above, whereas the liability gains and losses are not. Therefore, they must be tracked separately.

Q. TURNING TO THIS SECOND CONCEPT, PLEASE EXPLAIN WHAT YOU MEAN BY THE "PHASE IN" OF GAINS OR LOSSES.

A. The term "phase in" is used to describe the process of moving asset gains or losses into an amortization pool. Under FAS 87 and the ACM, the asset gains or losses are incorporated into the calculation of pension expense over a period of five years. Thus, 20 percent of a gain or loss is phased into the amortization

[3] IRC § 401(a)(2); Treas. Reg. § 1.401-2.

pool during the first year after the gain or loss occurs; another 20 percent is phased into the amortization pool during the second year after the gain or loss occurs, and so forth until the fifth year, when the full amount of the gain or loss is phased in. The gains and losses that enter the amortization pool are then amortized over a specific period of years if they satisfy the criteria I discuss below. Unlike asset gains or losses, liability gains and losses are not phased in.

Q. WHY ARE ASSET GAINS AND LOSSES PHASED IN BUT NOT LIABILITY GAINS AND LOSSES?

A. The assumptions used to establish pension liability (e.g., mortality rates, discount rates, etc.) typically do not vary greatly from year to year, and therefore, the drafters of FAS 87 did not consider it necessary to require the phase-in of liability gains and losses. In contrast, the market returns on pension fund assets can vary greatly from year to year. Because of the resulting potential effects of significant changing market returns on businesses' income statements, the drafters of FAS 87 decided that it was appropriate to phase-in market gains and losses.

Q. ARE EACH YEAR'S GAINS OR LOSSES CONSIDERED IN ISOLATION?

A. No. After the phase-in is completed, the current year's gains and losses are aggregated with the previously accumulated gains and losses.

Q. PLEASE DISCUSS THE THIRD CONCEPT YOU MENTIONED – THE AMORTIZATION OF GAINS AND LOSSES.

A. In addition to phasing the asset gains or losses into the amortization pool, the Company must undertake an analysis to determine whether it will actually amortize those gains or losses.

Q. HOW DOES THE COMPANY DETERMINE WHETHER IT WILL AMORTIZE GAINS OR LOSSES?

A. It depends on which plan is under review because the analysis for FAS 87 is not the same as the analysis for the ACM. For FAS 87, which governs the XES Plan, the Company aggregates its current year's gains or losses with the other accumulated gains or losses to calculate a net unamortized gain or loss. That net unamortized gain or loss is then compared to the present value of the projected benefit obligation (PBO) and to the market-related value of the assets in the pension trust. If the net unamortized gain or loss is outside a 10-percent corridor – that is, if it is more than 10 percent of the greater of the PBO or the market-related value of the trust assets – the Company must amortize that net gain or loss. If the net unamortized gain and loss is within the corridor, amortization does not occur.

If amortization of the unrecognized gains or losses is required, the amortization amount is equal to the amount of the unrecognized gain or loss in excess of the corridor divided by the average remaining future service of the active participants in the plan. For the Company's FAS 87 plan this is approximately 11 years.

For the ACM, which governs the NSPM Plan, the Company simply compares the market-related value of the pension trust assets to the PVFB. If the market-related value of the assets is greater than the PVFB, the plan is overfunded and there is no pension expense. Thus, there is nothing to be amortized. If the market value is less than the PVFB, the plan is underfunded, which means there is pension expense that is amortized over the remaining service lives of the employees within the actuarial formula.

Note, however, that I am using the term "amortization" as a type of shorthand insofar as the ACM is concerned. The difference between the market value of trust assets and the PVFB is not truly amortized in the sense that the amount is established in Year 1 and then that amount is fixed and recovered according to a schedule that provides for annual payments over the next several years. Instead, the Company undertakes the following process each year:

1) it calculates the difference between the market-related value of the assets and the PVFB.
2) if the PVFB exceeds the market-related value, the Company calculates the number of years over which to recover the difference.
3) the difference is divided by the number of years to determine the amount of pension expense that would need to be recovered in the current year in order to fund the shortfall.

In Year 2, however, this entire process is repeated, and the Company comes up with a new shortfall amount and a new period over which to fund it. The amount and the schedule from Year 1 are no longer relevant, because the Year 2 calculation "resets" the amount and the period over which the amount is to be funded.

In short, prior years' experience, whether positive or negative, is incorporated into the calculation of the current period recognition of pension expense. Exhibit___(RRS-1), Schedule 2, FAS 87 and ACM Amortization, contains a decision tree for FAS 87 and a decision tree for the ACM. Both show the process for determining whether to amortize gains or losses.

C. Calculation of Pension Expense under the ACM

Q. WHY DOES THE NSPM PLAN USE THE ACM TO ACCOUNT FOR PENSION EXPENSE?

A. NSPM began using the ACM to calculate pension expense in 1975. Although FAS 87 became the new standard for pension accounting for financial reporting purposes in 1987, it was made subject to the effects of rate regulation as provided for by FAS 71, which allowed regulated entities such as the NSPM Plan to reflect the "rate actions of a regulator" and the "effects of the rate-setting process" by regulatory agencies, such as the Commission. The authority provided by FAS 71 allowed the NSPM Plan to continue using the ACM for ratemaking purposes, as it had before 1987, and the Commission approved this continued use.

Q. PLEASE SUMMARIZE THE ACM AND EXPLAIN HOW PENSION COSTS ARE CALCULATED UNDER THAT METHOD.

A. The ACM is based on a normalized level of long-term cash funding requirements measured as a constant percentage of payroll. Under the ACM, the pension cost is the normalized amount that would need to be paid into the pension fund each year to fund earned benefits. Based on specific actuarial assumptions such as the discount rate, projected salary levels, and mortality, the PVFB is calculated and compared to the phased-in market-related value of plan assets. The difference between the PVFB and the market value of assets is the unfunded liability that must be funded over the future working lives of current employees. I have included a summary of the ACM in Exhibit___(RRS-1), Schedule 3, Description of Components and Calculations under ACM and FAS 87, along with a comparison to the FAS 87 method for calculating pension expense.

Q. Please provide an example of how the ACM works.

A. Suppose the Company determines, based on actuarial studies, that it will ultimately need $3 billion to fund its pension liability, which is the PVFB. If the market value of assets in the Company's NSPM Plan trust is currently $2.5 billion, there is a $500 million difference that will need to be funded. The ACM requires that the Company fund that amount based on the period approved by the Commission or the remaining future working lives of its employees, which is approximately 11 years. The Company then sets the pension expense at a levelized percentage of payroll based on the amount needed and the time remaining to fund the pension liability.

Q. How are the pension asset gain and loss experiences incorporated into the ACM calculation?

A. Recall that the ACM is calculated by comparing asset values to the PVFB. Thus, if there is an asset gain from the prior year, the phased-in amount of that asset gain is added to the market-related value of the assets; and if there is an asset loss, the phased-in amount of that loss is subtracted from the market-related value of the assets. Insofar as the PVFB is concerned, if there is a liability gain from the prior year, the PVFB is reduced by that amount. If the plan has a liability loss from the prior year, the PVFB grows by that amount. The difference between the asset value and the PVFB after incorporating the asset and liability gains and losses is the amount that is placed into the amortization pool and netted with the cumulative unrecognized gain and loss experiences.

Q. PLEASE PROVIDE AN EXAMPLE OF HOW THE CALCULATION WORKS.

A. Consider the example set forth earlier – the market value of assets is $2.5 billion and the PVFB is $3.0 billion, which creates a funding obligation of $500 million in Year 1. Now suppose the following events occur:

- The actuarially determined EROA for Year 1 was seven percent, but the fund actually earned six percent. In that instance, the fund would have an asset loss of $25 million ($2.5 billion x .01 = $25 million).
- The actual discount rate in Year 1 was 25 basis points higher than the actuaries had assumed, which reduced the PVFB by $15 million. Thus, the fund has a liability gain of $15 million for Year 1.
- The pension fund paid out $175 million in benefits in Year 1, which is exactly equal to the expected earnings on the plan's assets during that year ($2.5 billion assets x .07 EROA = $175 million).

Because the amounts paid out as benefits equal the EROA, the only changes that need to be incorporated in the Year 2 pension expense are the asset loss and the liability gain. The Year 1 asset loss was $25 million, but under the phase-in rules, only $5 million (i.e., 20 percent) of that loss is reflected in the market value of assets in Year 2. On the other hand, the entire $15 million liability gain is recognized in Year 2, so the Year 2 asset value drops by $5 million and the Year 2 PVFB drops by $15 million. Now the difference between the market value of the assets and the PVFB is $490 million instead of $500 million. That $490 million is then spread over the amortization period approved by the Commission.

Q. IN THAT EXAMPLE, WHAT HAPPENS TO THE ASSET LOSSES THAT HAVE NOT BEEN PHASED IN AND AMORTIZED YET?

A. The amount is reflected on the Company's books as an increase to the liability offset by a regulatory asset, resulting in no change to the net balance sheet amount of the pension plan. As discussed earlier, an additional amount of the asset losses will be phased into the amortization pool each year for the next four years and will reduce the regulatory asset by a corresponding amount each year, all else being equal.

Q. THE NSPM PLAN CURRENTLY HAS PRIOR-PERIOD ASSET LOSSES AND PRIOR-PERIOD LIABILITY LOSSES, BOTH OF WHICH INCREASE THE AMOUNT OF PENSION EXPENSE IN THE CURRENT YEAR. HAVE THE COMPANY'S CUSTOMERS BENEFITED FROM ASSET GAINS AND LIABILITY GAINS IN THE PAST?

A. Yes. For many years the Company had significant gains because its pension plan investments benefited from a significant and prolonged upward market movement, and customers reaped the benefits through market gains that exceeded the EROA. In other years, as with any investment, there are market losses. But overall, from 1950 through 2022, the Xcel Energy total plan has had significant net gains that benefit customers by increasing the value of the pension fund. NSPM customers share in these benefits, as set forth in Exhibit___(RRS-1), Schedule 4, XEPP Fund Analysis, which I describe in further detail below.

Q. IS THE COMPANY ASKING ITS CUSTOMERS TO RESTORE LOSSES FROM PRIOR YEARS?

A. No. We are simply calculating the current year's pension expense, which is affected by cumulative gain and loss experiences. Expense is determined by prior experience, and customers have benefitted from the prior gains. Therefore, it is reasonable, appropriate, and necessary to reflect both prior-period gain and loss experiences in current pension expense.

Q. HOW HAVE THE PRIOR GAIN EXPERIENCES BEEN INCORPORATED INTO THE COMPANY'S PENSION EXPENSE?

A. Prior gain experiences have been incorporated in the same way the prior loss experiences were incorporated. For the NSPM Plan, the asset gains and liability gains reduced the amount that needed to be funded, which reduced the pension expense charged to customers. For the XES Plan, the asset gains and liability gains have offset the service costs and interest costs that our customers would otherwise have paid in rates.

Q. DO YOU HAVE DATA TO SHOW HOW CUSTOMERS HAVE BENEFITED FROM PENSION ASSET GAINS?

A. Yes. Schedule 4 quantifies the significant benefits that the Company's pension assets have provided to customers. Schedule 4 shows the Xcel Energy Pension Plan (XEPP) Trust activity since its inception in 1950. Although Schedule 4 reflects more than just the NSPM Plan, it does demonstrate the overall value of the pension assets, which include the NSPM assets.[4] Since 1950, the Company has contributed approximately $1.6 billion into the trust while earning approximately $4.5 billion in investment returns, which helped pay for

[4] As of December 31, 2022, the NSPM Plan owned 40 percent of the total XEPP plan assets.

approximately $5.1 billion in payments to employees. For many years these asset returns enabled the Company to recognize pension benefit costs at or very close to zero and to make no pension contributions. These low or nonexistent pension expense amounts were reflected in our rate cases, which means that customers paid much less in annual pension cost than they would have paid in the absence of the pension asset gains.

Q. WHAT HAS THE COMPANY DONE WITH THOSE GAINS?

A. As I noted earlier, by law, earnings on pension trust assets cannot be removed from the trust fund. Therefore, the net gains on the pension asset have been used to reduce the pension expense charged to our customers and have mitigated cash funding requirements.

Q. IS THERE ANY OTHER WAY IN WHICH CUSTOMERS HAVE BENEFITED FROM THE PENSION ASSET GAINS?

A. Yes. For more than 50 years the Company's pension plan has provided a market-competitive employee benefit, which allowed us to attract and retain employees that helped us build, operate, and maintain the gas system that continues to provide safe, reliable gas service. The pension asset gains have helped the Company provide that benefit at a much lower cost than would have been possible without the asset gains.

D. Calculation of Pension Expense under FAS 87

Q. PLEASE PROVIDE AN OVERVIEW OF FAS 87.

A. FAS 87 is an accounting standard adopted by the Financial Accounting Standards Board (FASB) in 1987 to govern employers' accounting for pensions. Under FAS 87, pension cost is generally made up of five components of costs, but a sixth component can be required provided certain criteria are met during the year. The five main components of FAS 87 pension cost are:

1) the present value of pension benefits that employees will earn during the current year (service cost).
2) increases in the present value of the PBO that plan participants have earned in previous years (interest cost).
3) expected investment earnings during the year on the pension plan assets, or EROA.
4) recognition of prior-period gains or losses (e.g., investment earnings different from assumed or amortization of unrecognized gains and losses).
5) recognition of the cost of benefit changes the plan sponsor provides for service the employees have already performed (amortization of unrecognized prior service cost).

Q. TAKING EACH OF THESE FIVE COMPONENTS IN ORDER, HOW IS THE SERVICE COST COMPONENT CALCULATED?

A. The service cost component recognized in a period is the actuarial present value of benefits attributed by the pension benefit formula to current employees' service during that period. In effect, the service cost is the value of benefits that the employees have earned during the current period. Actuarial assumptions are used to reflect the time value of money (the discount rate) and the probability of payment (assumptions as to mortality, turnover, early retirement, and so forth).

Q. NEXT, HOW IS THE INTEREST COST COMPONENT CALCULATED?

A. The interest cost component recognized in a fiscal year is determined as the increase in the plan's total PBO due to the passage of time. Measuring the PBO as a present value requires accrual of an interest cost at a rate equal to the assumed discount rate. Essentially, the interest cost identifies the time value of money by recognizing that anticipated pension benefit payments are one year closer to being paid from the pension plan.

Q. HOW IS THE THIRD COMPONENT, EROA, CALCULATED?

A. The EROA is determined based on the expected long-term rate of return on the market value of plan assets. The market value of plan assets is a calculated value that recognizes changes in the fair value of assets in a systematic and rational manner over not more than five years. The EROA is an offset to the service costs and interest costs, and therefore it reduces the amount of pension expense.

Q. CAN YOU PROVIDE AN EXAMPLE OF HOW THE INVESTMENT EARNINGS REDUCE THE AMOUNT OF PENSION EXPENSE?

A. Yes. Assume that the pension trust fund has a beginning asset balance of $500 million and the expected EROA in that year is eight percent. The expected return is $40 million ($500 million x 8 percent). This amount will be used to offset the other components within the pension cost determination. Further assume that these other components are as follows: Service Cost ($25 million), Interest Cost ($20 million), and Loss Amortization ($30 million). The net periodic pension cost for the year would be $35 million as shown in Table 2:

Table 2
Annual Pension Expense Example

Amounts in Millions				
Service Cost	Interest Cost	Loss Amortization	EROA	Total
$25	$20	$30	$(40)	$35

As shown in Table 2, the pension cost would have been $75 million in the absence of the investment earnings. If the actual earned return in a particular year is higher than the EROA, customers will enjoy even more savings in future years as the asset gain is phased into pension expense.

Q. HAVE THE COMPANY'S CUSTOMERS EXPERIENCED THOSE TYPES OF SAVINGS IN PRIOR YEARS?

A. Yes. As I explained previously, the Company's annual pension cost included in rates has been significantly lower in prior years as a result of the earnings on the FAS 87 pension assets because those earnings helped reduce the amounts contributed by customers, relative to the true cost of the pension benefits.

Q. WITH REGARD TO THE FOURTH COMPONENT, WHAT ARE THE UNRECOGNIZED GAINS AND LOSSES?

A. The unrecognized gains and losses are the asset gains or losses and the liability gains or losses that I discussed earlier. The asset gains or losses occur because the actual earned return on assets was different from the EROA in prior years. The liability gains or losses occur because the actual values experienced in prior years, such as the discount rate and wage assumptions, were different from what was expected. The asset gains or losses are phased in according to the five-year schedule I discussed earlier, and then they are netted with not only the liability gains and losses from the previous year, but also the unamortized gains and losses from prior years. If the net unamortized gains or losses fall outside the ten-percent corridor, they are amortized over the remaining service lives of the Company's employees.

Q. PLEASE EXPLAIN IN MORE DETAIL THE PROCESS FOR DETERMINING WHETHER THE GAIN AND LOSS AMOUNT UNDER FAS 87 SHOULD BE AMORTIZED.

A. As noted in the decision tree that appears in Schedule 2, the determination of the gain or loss amortization is a multi-step process composed of the following steps:

1) The Company first determines whether it has an asset gain or loss by comparing the actual return on assets for the prior year to the EROA for the prior year.
2) To the extent there is an asset gain or a loss, the Company phases in 20 percent of that gain or loss. The Company will also phase in portions of gains and losses from prior years that have not been fully phased in. They are phased in at the rate of 20 percent per year.
3) The Company then calculates the gain or loss on the PBO by comparing the actual year-end PBO from the prior year to the expected year-end PBO for the prior year.
4) The Company next aggregates the cumulative net gains and losses from all prior years to arrive at the cumulative unrecognized gains or losses.
5) If the cumulative unrecognized gains and losses are more than 10 percent of the greater of the PBO or the market value of assets, the balance of gains and losses that falls outside the corridor is amortized over the average expected remaining years of service of the Company's employees.

Q. IS THIS THE SAME PROCESS THAT THE COMPANY HAS FOLLOWED SINCE THE ORIGINATION OF THE XES PLAN?

A. Yes. The Company was required to set the phase-in period, as well as the basis for amortizing gains and losses at the time it adopted FAS 87, and it is not permitted to deviate from that basis from year to year.

Q. WITH RESPECT TO THE FIFTH COMPONENT OF THE PENSION COST CALCULATION, WHAT IS UNRECOGNIZED PRIOR SERVICE COST?

A. Plan amendments can change benefits based on services rendered in prior periods. FAS 87 does not generally require the cost of providing such retroactive benefits (prior service cost) to be included in net periodic pension cost entirely in the year of the amendment, but instead provides for recognition over the future years.

Q. HOW IS UNRECOGNIZED PRIOR SERVICE COST AMORTIZED?

A. Unrecognized prior service cost is amortized over the expected remaining years of service of the participants impacted by the benefit change. Also, there is no ten-percent corridor for this purpose.

Q. HOW HAS THE COMPANY TREATED THE ASSET GAINS OF THE XES PLAN?

A. As noted earlier in connection with the NSPM Plan, all net asset gains have been used to reduce pension expense.

Q. Does the amortization amount of unrecognized gains and losses represent the entire FAS 87 expense?

A. No. As I discussed earlier, it is only one component of the FAS 87 pension expense. The service costs, interest costs, EROA, and recognition of prior service costs are also components of the FAS 87 expense.

Q. You had mentioned previously that a sixth component of pension cost can be required; what is that?

A. A sixth component, FAS 88 settlement accounting, can be required provided certain criteria are met during the year. Settlement accounting is required if lump-sum payments to employees in a year are greater than the sum of the service cost and interest cost components recognized for that year. This criterion for settlement accounting was met in 2021 and 2022 for the XEPP. The XEPP's participant population has a significant proportion of participants at or nearing retirement age. The Company has seen significantly more lump-sum pension payouts in 2021 and 2022 than in years past, thus exposing the plan to settlement accounting requirements. The Company did not experience a settlement in 2019 and 2020. When settlement accounting is triggered, the Company is immediately required to recognize a portion of unrealized losses currently deferred as a regulatory asset. When settlement accounting is not triggered, the unrecognized gain or loss is amortized over a much longer period of time.

Q. DOES SETTLEMENT ACCOUNTING RESULT IN AN INCREASE IN THE OVERALL PENSION EXPENSE?

A. No. Settlement accounting is not an increase in the overall pension expenses, but rather an acceleration of the timing of when the pension expense will be recognized.

Q. DOES THE ACM ALSO HAVE A SETTLEMENT ACCOUNTING PROVISION?

A. No. The ACM does not have a settlement accounting provision. Settlement accounting accelerates the timing of when cost is accrued under Accounting Standards Codification (ASC) 715 (FAS 87) but does not change the amount of cash contributions needed to fund the plan. Since the ACM is a cash-funding-based pension cost method rather than an accrual method, there is no settlement accounting requirement or provision.

E. Pension Funding

Q. DO THE ACM AND FAS 87 ALSO GOVERN HOW RETIREMENT PLANS MUST BE FUNDED?

A. No. The funding of retirement plans is determined based upon prudent business practices as limited by the provisions of the Employee Retirement Income Security Act (ERISA), the Pension Protection Act, and the Internal Revenue Code (IRC). Under those laws and regulations:

- There are minimum required contributions.
- There are maximum contributions that can be deducted for tax purposes.
- The plan sponsor has a fiduciary responsibility to prudently protect the interests of the plan participants and beneficiaries.

Over the long run, the cumulative employer contributions made to a plan in accordance with ERISA, the Pension Protection Act, and the IRC rules will be roughly equal to the cumulative pension expense recorded under both the ACM and FAS 87; but in the short and intermediate run, there can be significant differences. The cumulative difference between pension contributions and recognized pension expense gives rise to a prepaid pension asset or a pension liability, both of which I will explain in greater detail later in my testimony.

IV. PENSION ASSUMPTIONS

Q. PLEASE SUMMARIZE THE PRIMARY PENSION ASSUMPTIONS USED TO DETERMINE THE TEST YEAR PENSION COST.

A. The primary pension assumptions used to determine the test year pension costs are the discount rate and the EROA. The Company used the following assumptions in Table 3 to determine 2024 pension expense:

Table 3
2024 Pension Assumptions

Company – Accounting Method	Discount Rate	EROA
NSPM – Aggregate Cost Method (ACM)	7.25%	7.25%
XES – FAS 87 (ASC 715)	5.80%	7.25%

Q. HAS THE COMPANY PROVIDED OBJECTIVE, VERIFIABLE MEASURES TO EVALUATE THE ASSUMPTIONS?

A. Yes. We have provided objective, verifiable measures where they are available. For example, we used benchmark indexes to evaluate the reasonableness of the discount rate produced by our bond-matching study. For the EROA assumptions, we gathered information from the 2022 Edison Electric Institute

(EEI) survey results for fiscal year 2022, and we compared those other utilities' assumptions to ours. The results are shown on Exhibit___(RRS-1), Schedule 5.

Q. WHAT DOES THE COMPARISON SHOW?

A. The EROA and wage increase assumptions used for the NSPM Plan and the XES Plan are at or near the average of the 43 EEI companies who responded to the survey.

1) The NSPM Plan discount rate of 7.25 percent is much higher than the average discount rate of 5.44 percent for the 43 EEI companies who responded to the survey. This is because the ACM requires that the discount rate be set equal to the EROA, which affects only companies using ACM. A higher discount rate assumption lowers the cost, so the NSPM discount rate assumption lowers pension cost as compared to other utilities, all else equal.

2) The XES FAS 87 discount rate is 5.80 percent, compared to the EEI survey average of 5.44 percent.

3) The NSPM Plan and the XES Plan EROA assumptions of 7.25 percent are slightly higher than the 6.97 percent average for the EEI companies.

A. Discount Rate Assumption

Q. WHAT DISCOUNT RATE DID THE COMPANY USE TO CALCULATE QUALIFIED PENSION EXPENSE?

A. The Company used a 5.80 percent discount rate to calculate the pension expense included in rates. Table 4 below shows how that discount rate compares to prior years' discount rates.

Table 4
Pension Discount Rate

Expense Period	**2020**	**2021**	**2022**	**2023-2024**
Measurement Date	12/31/2019	12/31/2020	12/31/2021	12/31/2022
XES FAS 87	3.48%	2.65%	3.07%	5.80%

Q. WILL THE COMPANY PROVIDE AN UPDATED DISCOUNT RATE TO INCORPORATE THE MOST RECENT MEASUREMENT DATE?

A. Yes. As we have done in prior rate cases, the Company will provide an updated discount rate in Rebuttal Testimony to incorporate the most recent measurement date of December 31, 2023, which will be available in late January or early February of 2024.

Q. PLEASE DESCRIBE HOW THE DISCOUNT RATE LISTED ABOVE IN TABLE 4 WAS DETERMINED.

A. The Company uses multiple reference points to set the discount rate. The primary basis for valuation is a bond-matching study that is performed as of December 31 of each year. The bond-matching study selects a matching bond for each of the individual projected payout durations within the plan based on projected actuarial experience, as compiled by the Company's actuary, Willis Towers Watson. The bonds selected must have a rating of Aa/AA or higher and not have a pending review as of December 31. In addition, the bond may not have an inconsistent rating between agencies where any agency rates the bonds below Aa/AA. If bonds are not available for a specific duration within the plan, a bond with the next closest shorter duration is used to determine the discount rate.

The Company also uses other reference points to validate the rate calculated by the bond-matching study, including the Merrill Lynch Corporate (AA-AAA) 15+ Bond Index. In addition to these reference points, the Company also reviews general survey data provided by Willis Towers Watson and EEI to assess the reasonableness of the discount rate selected.

The Company has consistently used the bond-matching approach, along with the corroborating methods, because it provides the most accurate discount rate of the available alternatives that meet applicable standards of FAS 87. Further information pertaining to the determination of discount rates is provided in Exhibit___(RRS-1), Schedule 6, Determination of Discount Rates and EROA Assumptions. These standards and the review processes described below support the use of the discount rate that is used to determine pension expense for the XES Plan.

Q. DESCRIBE THE FINANCIAL VALIDATION PROCESS AND CONTROLS THAT ARE IN PLACE REGARDING SETTING THE DISCOUNT RATE.

A. The Company has a senior leadership team that reviews preliminary discount rates in late December with potential year-end scenarios. Because discount rates are not set until the December 31 rates are available, the review at the initial meeting is primarily to set expectations. Year-end discount rates are developed using a bond-matching study applied to projections of future cash outflows for benefit payments, as I described earlier. Bond-matching study results are reviewed jointly with the Company Controller, the area vice president in charge of benefits accounting, and representatives from Willis Towers Watson. Each individual bond is analyzed to consider any attributes that would make it inappropriate for the bond-matching study. This includes any known risk of downgrade to the bond, any deviation in yield from other bonds of the same duration, and the total outstanding and traded value of the bond. The results of the study are compared to publicly available sources such as the Merrill Lynch Corporate (AA-AAA) 15+ Bond Index to validate the reasonableness of the discount rate determined using the bond-matching study. Any unusual deviations between these numbers are researched to understand the underlying drivers.

Bonds selected in the bond-matching study are revalidated by Willis Towers Watson prior to the filing of the Company's 10-K to ensure that individual bonds selected have not been downgraded or put on watch. In addition, employee data used to determine the projected future payments is compared to previous years for reasonableness of the headcount and pay rate information, both internally and by Willis Towers Watson. Final discount rates are communicated back to the senior leadership for approval, and the final approved rate is included in the meeting minutes. Final approved discount rate assumptions are then provided to the audit committee as part of the Company's critical accounting policies.

In addition to the year-end discount rate analysis, discount rates are regularly recalculated over the course of the year by Goldman Sachs, Willis Towers

Watson, and independently by Company personnel using projected cash flows combined with publicly published Merrill Lynch Corporate (AA-AAA) 15+ Bond Index to understand the expected impact of changing rates as market conditions change. Changes in the 10-year Treasury rate and the Merrill Lynch Corporate (AA-AAA) 15+ Bond Index are used as indicators that pension discount rates are likely deviating from current assumptions and will often drive incremental estimates of expected discount rates.

Q. HOW WAS THE 7.25 PERCENT NSPM PLAN DISCOUNT RATE DETERMINED?

A. Pension expense for the NSPM Plan is based on the ACM, which requires use of the long-term EROA as the discount rate. Thus, the determination of the appropriate level of EROA, which is discussed below, also addresses the appropriateness of the ACM discount rate.

Q. WHAT IS YOUR CONCLUSION REGARDING THE DISCOUNT RATES USED FOR THE XES PLAN AND THE NSPM PLAN?

A. The test year discount rates for the XES Plan of 5.8 percent and the NSPM Plan of 7.25 percent are reasonable, and in the case of NSPM Plan is well above the average rates used by other companies.

Q. WILL THE COMPANY UPDATE ITS PROPOSED DISCOUNT RATE?

A. Yes. Consistent with the past practice, the Company will recalculate its test year pension cost using a measurement date of December 31, 2023, to capture the most current pension position and to provide an update to all elements of cost.

B. EROA Assumption

Q. WHAT IS THE TEST YEAR EROA?

A. The test year EROA is 7.25 percent.

Q. HAS THAT EROA INCREASED SINCE THE COMPANY'S LAST GAS RATE CASE?

A. The Company increased the EROA assumption primarily because the risk-free interest rates (e.g., U.S. Treasury Bonds), which are a building block of asset returns, have continued to increase. A higher risk-free rate generally reduces forward looking expected returns.

Q. HOW WAS THE TEST YEAR EROA ASSUMPTION DETERMINED?

A. The EROA is, and must be, determined based on the long-term expected rates of return as dictated by the requirements of the ACM and FAS 87. The Company bases investment return assumptions on expected long-term performance for each of the investment types included in our pension asset portfolio – equity investments (such as corporate common stocks), fixed-income investments (such as corporate bonds and U.S. Treasury securities), and alternative investments (such as private equity, hedge fund-of-funds and real assets). In reaching return assumptions, the Company considers the actual historical returns achieved, as well as the long-term return levels projected and recommended by investment experts in the marketplace. Xcel Energy continually reviews its pension investment assumptions in order to maintain investment portfolios that provide adequate rates of return at appropriate levels of risk. Further information pertaining to the determination of EROA is provided in Schedule 6.

Q. DESCRIBE THE FINANCIAL VALIDATION PROCESS AND CONTROLS THAT ARE IN PLACE REGARDING SETTING THE EROA ASSUMPTION.

A. The Xcel Energy Treasury group, along with Goldman Sachs, establishes a target investment mix. This investment strategy and mix are then presented to the Executive Management team for approval by the Controller. The target portfolio investment mix has an expected long-term return based on Goldman Sachs' long term expected asset class returns. The expected long-term returns are validated for reasonableness by comparing them against expected returns provided by Willis Towers Watson, and in some cases, other investment advisory groups' returns. The range around the median return helps account for the differences in factors associated with the constructions of the underlying asset class return, risk, and correlation forecasts. Key contributing factors may include, but are not limited to: time horizon, construction methodology, valuation assessment, interest rate forecast, inclusion of expected alpha, fees, or term premium, and inflation assumptions. The validated long term expected returns for each plan are then included in the assumptions provided for Executive review, and upon approval are included in the Xcel Energy's critical accounting policies provided to the audit committee.

Q. DOES THE COMPANY COMPARE ITS EROA TO OTHER COMPANIES?

A. Yes. The Company compares its EROA to other utilities and also to general industry data. Schedule 5 shows that the Company's long-term EROA assumption of 7.25 percent is slightly higher than the average of 6.97 percent for the EEI utilities.

Q. WHAT IS YOUR CONCLUSION REGARDING THE 7.25 PERCENT EROA?

A. The 7.25 percent EROA assumption is reasonable based on the discussion and factual information outlined above.

V. QUALIFIED PENSION AND 401(K) MATCH COSTS

Q. WHAT DO YOU DISCUSS IN THIS SECTION OF YOUR TESTIMONY?

A. I quantify the test year expense amounts for qualified pension and the 401(k) match.

A. Qualified Pension Expense

Q. WHAT IS THE LEVEL OF QUALIFIED PENSION EXPENSE IN THE TEST YEAR?

A. The 2024 qualified pension expense amount is $2.2 million. That amount includes costs related to both the NSPM Plan and the XES Plan. Approximately 83 percent of the Company's qualified pension expense relates to the NSPM Plan and 17 percent relates to the XES Plan.

Q. DO THE NSPM PLAN AND THE XES PLAN DETERMINE THEIR QUALIFIED PENSION EXPENSE USING DIFFERENT METHODS?

A. Yes. As I indicated in an earlier section of my testimony, the ACM continues to be used to determine the expense of the NSPM Plan. Thus, the pension expense for that plan consists of a levelized percentage of payroll that is sufficient to recover the current year's portion of the difference between the PVFB and the asset value. In contrast, costs of the XES Plan costs are established based on the five elements prescribed by FAS 87 – service cost, interest cost, the EROA, unrecognized gains or losses, and unrecognized prior service costs.

Q. ARE THE TWO METHODS BASED ON ANY COMMON ASSUMPTIONS?

A. Yes. To calculate the pension liability under both methods, it is necessary to make assumptions about the discount rate and demographics (including attrition, expected wage increases, etc.). The assumptions are established at the end of each year, and they are used to determine book expense for the subsequent year. Accordingly, the 2023 assumptions were finalized as of December 31, 2022, and the 2024 assumptions will be finalized as of December 31, 2023. The final 2023 assumptions will be available in late January 2024. The Company has typically included updated cost amounts in Rebuttal Testimony. We also recognize that our updates should be objectively validated when possible, and we will provide the available validation measures in both this testimony and my Rebuttal Testimony. I provided detailed support for each of the two major pension assumptions in the prior section of my testimony.

Q. WHAT WERE THE AMOUNTS OF QUALIFIED PENSION EXPENSE IN THE FOUR YEARS PRIOR TO THE TEST YEAR, AND WHAT DOES THE COMPANY EXPECT THEM TO BE OVER THE NEXT FEW YEARS?

A. Table 5 below shows pension expense amounts since 2020 and the Company's current forecast of qualified pension expense. The forecast for 2023 and 2024 assumes no changes in assumptions for the EROA, discount rate, plan contributions, wage increases, and employee turnover. The forecast also assumes that actual experience matches these assumptions, including the Company's actual return on assets equaling the EROA in 2023 and 2024.

Table 5
Qualified Pension Expense
NSPM Gas O&M State of MN

Year	Amount ($)
2020	2,356,793
2021	2,521,178
2022	2,139,260
2023 Forecast	2,397,493
2024 Test Year	2,269,317

Q. WHAT ARE THE MAJOR DRIVERS OF THE DECREASE IN QUALIFIED PENSION EXPENSE?

A. The major drivers of the changes in qualified pension expense are:

- Favorable asset returns in 2020 and 2021, offset by reduced market returns on assets in 2022.
- Reduced benefits for new hires compared to employees terminating and retiring.
- Improved funded status from recognition of contributions and expected return on assets.

Q. PLEASE DESCRIBE HOW CONTRIBUTIONS AND THE EXPECTED RETURN ON ASSETS CONTRIBUTE TO THE DECREASE IN PENSION EXPENSE.

A. Because of funding requirements mandated by the Pension Protection Act of 2006, the Company has made significant contributions to the pension trust funds in recent years. Those contributions increase the assets upon which the pension plan earns a return, and those returns are an offset to annual pension cost. Thus, the increase in the asset base helps to reduce annual pension cost.

Q. PLEASE DISCUSS HOW PENSION PLAN DESIGN CHANGES CONTRIBUTE TO THE DECREASE IN PENSION EXPENSE.

A. Plan design changes implemented in 2011 and 2012 significantly reduced benefit levels for newly hired bargaining and non-bargaining employees. Each year as new employees are hired, the Company will continue to see increased savings as new employees are enrolled in the revised pension benefit plan. In addition, effective on January 1, 2018, the annual Retirement Spending Account credits were eliminated on a going-forward basis for all non-bargaining employees, and the Social Security Supplement was eliminated for all non-bargaining employees who did not meet certain criteria, including retirement eligibility, by December 31, 2022.

Q. HAS THE COMPANY PROVIDED THE ACTUARIAL STUDY AND DERIVATION OF THE JURISDICTIONAL AMOUNT?

A. Yes. The Company has included Exhibit___(RRS-1), Schedule 7, 2024 Actuarial Studies, which is an actuarial study that supports the qualified pension costs included in the test year. Exhibit___(RRS-1), Schedule 8, 2024 Actuarial Costs, shows the conversion of the 2024 total cost amounts to the NSPM gas O&M, State of Minnesota amount.

B. 401(k) Match

Q. WHAT IS THE 401(K) MATCH EXPENSE AMOUNT IN 2024?

A. The 2024 401(k) match expense amount is approximately $1.0 million.

Q. WHAT WERE THE AMOUNTS OF 401(K) MATCH EXPENSES IN THE FOUR YEARS PRIOR TO THE TEST YEAR COMPARED TO THE FORECASTED AMOUNTS FOR 2024?

A. Table 6 below shows the amounts of 401(k) match expense from 2020 through

2022, as well as the forecasted amounts in 2023 and the 2024 test year.

Table 6
401(k) Match Expense

NSPM Gas O&M State of MN	
Year	**Amount ($)**
2020	796,013
2021	876,326
2022	934,779
2023 Forecast	1,080,627
2024 Test Year	1,098,582

Q. WHAT ASSUMPTIONS WERE USED TO DEVELOP THE 401(K) MATCH EXPENSE FOR 2024?

A. The most recent actual 401(k) match, which was from the 2022 401(k) plan year, was used as the base year. This base year amount was then increased by the 2023 estimated and 2024 budgeted merit increases to derive the amount in 2024.

Q. WHY IS THE AMOUNT OF 401(K) EXPENSE INCREASING EACH YEAR?

A. The 401(k) expense is increasing because the contribution is calculated based on a percentage of salary, and merit salary increases cause the total labor costs to increase each year. Moreover, the Company has experienced an overall increase in 401(k) participation in recent years, and that trend is expected to continue.

C. Qualified Pension and 401(k) Match Benefits Summary

Q. PLEASE SUMMARIZE THE COMPANY'S REQUEST REGARDING THE TEST YEAR AMOUNTS FOR THESE BENEFITS.

A. The Company requests that the Commission approve the 2024 qualified pension expense amount of $2,269,317 and the 401(k) match expense amount of $1,098,582.

Q. IS IT REASONABLE TO ASK CUSTOMERS TO PAY FOR QUALIFIED PENSION AND 401(K) MATCH BENEFIT COSTS?

A. Yes. It is appropriate that customers pay for these benefits because they reflect a reasonable and necessary level of expense. As explained in more detail in the testimony of Company witness Deselich, our compensation and benefits plans are required to attract, retain, and motivate employees needed to perform the work necessary to provide quality services for NSPM customers. Without the pension plan and 401(k) matching benefits, the Company would have to pay significantly higher current compensation to attract employees.

VI. RETIREE MEDICAL AND FAS 112 LONG-TERM DISABILITY BENEFITS

Q. WHAT DO YOU DISCUSS IN THIS SECTION OF YOUR TESTIMONY?

A. I discuss the Company's request to recover the expense for post-retirement healthcare benefits under FAS 106, Employers' Accounting for Post-Retirement Benefits Other Than Pensions, and for post-employment long-term disability (LTD) benefits under FAS 112, Employers' Accounting for Post-Employment Benefits.

Q. PLEASE EXPLAIN THE DIFFERENCE BETWEEN FAS 106 AND FAS 112 LTD BENEFITS.

A. The FAS 106 benefits are primarily post-retirement healthcare benefits. FAS 112 encompasses a number of benefits, including LTD, self-insured workers' compensation, and continuation of life insurance.

A. Retiree Medical

Q. DOES THE COMPANY STILL OFFER FAS 106 RETIREE MEDICAL BENEFITS TO ITS ACTIVE EMPLOYEES?

A. No. The Company eliminated FAS 106 retiree medical benefits for all active non-bargaining and bargaining employees more than ten years ago. The current expense for retiree medical benefits is a legacy of the prior programs. But even though there are no new entrants into the plan, current employees who were hired prior to the termination date are still eligible for this benefit.

Q. PLEASE EXPLAIN HOW RETIREE MEDICAL COSTS ARE DETERMINED.

A. The components and calculation of FAS 106 are identical to FAS 87, with one exception. Unlike FAS 87, FAS 106 asset gains or losses are not phased in before they are amortized; instead, the total gain or loss amount is simply amortized over the average years to retirement for active employees. Otherwise, the FAS 106 benefits are calculated based on assumptions regarding the discount rate, the EROA, and the salary or wage levels.

Q. WHAT ARE THE ASSUMPTIONS REGARDING THE DISCOUNT RATE AND THE EROA FOR THE TEST YEAR?

A. The 2024 test year reflects an EROA of 5.00 percent for both bargaining and non-bargaining employees and a 5.80 percent discount rate.

Q. PLEASE DESCRIBE HOW THE 5.80 PERCENT DISCOUNT RATE WAS DETERMINED FOR THIS RATE CASE.

A. The Company determined the 5.80 percent discount rate consistent with the qualified pension expense calculation. Table 7 below shows how the test year discount rate compares to prior years.

Table 7
FAS 106 Retiree Medical Discount Rate

Expense Period	**2019**	**2020**	**2021**	**2022**	**2023-2024 Forecasted**
Measurement Date	**12/3/2018**	**12/31/2019**	**12/31/2020**	**12/31/2021**	**12/31/2022**
Discount Rate	4.32%	3.47%	2.65%	3.09%	5.80%

Q. WILL THE COMPANY PROVIDE AN UPDATED DISCOUNT RATE TO INCORPORATE THE MOST RECENT MEASUREMENT DATE?

A. Yes. As we have done in prior rate cases, the Company will provide an updated discount rate in Rebuttal Testimony to incorporate the most recent measurement date of December 31, 2023, which will be available in late January or early February of 2024.

Q. PLEASE DESCRIBE HOW THE DISCOUNT RATES LISTED ABOVE IN TABLE 7 WERE DETERMINED.

A. The process for determining the discount rate for retiree medical is the same as for pension and is built from the same portfolio of bonds developed through the Company's bond-matching study. This common set of bonds is then applied to the plan-specific cash flows to arrive at a weighted average discount rate appropriate for each individual plan.

Q. HOW DO THE AMOUNTS OF FAS 106 RETIREE MEDICAL EXPENSE IN THE FIVE YEARS PRIOR TO THE TEST YEAR COMPARE TO THE FORECAST FOR 2023 AND 2024?

A. As Table 8 below shows, the test year retiree medical costs have increased over the past five years. This increase in retiree medical costs is primarily due to the following:

- Fully amortizing the prior service credit resulting from the transition of Medicare eligible retirees to the HRA benefit.
- Reduced market returns on assets in 2022.

Table 8
FAS 106 Retiree Medical Expense
NSPM Gas O&M State of MN

Year	Amount ($)
2020	77,226
2021	61,591
2022	447
2023 Forecast	195,790
2024 Test Year	225,398

Q. HAS THE COMPANY PROVIDED THE ACTUARIAL STUDY AND DERIVATION OF THE JURISDICTIONAL AMOUNT?

A. Yes. The Company has included Schedule 7, which is an actuarial study that supports the FAS 106 costs for 2023-2024. Schedule 8 shows the conversion of the 2024 total cost amounts to the NSPM gas O&M, State of Minnesota amount.

B. FAS 112 Long-Term Disability Benefits

Q. PLEASE DESCRIBE FAS 112 LONG-TERM DISABILITY BENEFITS AND EXPLAIN HOW THEY ARE ACCOUNTED FOR.

A. LTD benefits are provided by the Company to former or inactive employees after employment but before retirement. The LTD plan provides the employee income protection by paying a portion of the employee's income while he or she is disabled by a covered physical or mental impairment.

The accounting treatment varies depending on whether the cost is self-insured or fully-insured. In a fully-insured plan, the Company purchases an insurance plan from an outside insurance provider that assumes the risk. In a self-insured plan, the Company provides the benefits to the covered individuals and therefore, effectively acts as the insurer. For the self-insured piece, the Company is required to accrue for LTD costs under FAS 112, while the fully-insured piece is simply the cost of the insurance premium incurred each year along with any other miscellaneous costs. The FAS 112 accrual represents the expected disability benefit payments for employees that are not expected to return to work.

Q. WHAT GROUPS OF EMPLOYEES ARE COVERED UNDER THE SELF-INSURED BENEFIT AND WHICH GROUPS ARE COVERED UNDER THE FULLY INSURED BENEFIT?

A. All non-bargaining employees disabled prior to January 1, 2008 and NSPM bargaining employees disabled prior to January 1, 2014 are covered under the self-insured plan; all employees disabled after these dates are covered under a fully insured plan.

Q. WHAT WERE THE AMOUNTS OF FAS 112 LONG-TERM DISABILITY EXPENSE IN THE FOUR YEARS PRIOR TO THE TEST YEAR AND THE TEST YEAR?

A. Table 9 below compares the FAS 112 long-term disability benefit costs from 2020 through 2024.

Table 9
FAS 112 Long-Term Disability Expense

NSPM Gas O&M State of MN	
Year	**Amount ($)**
2020	37,737
2021	44,537
2022	(75,768)
2023 Forecast	(6,818)
2024 Test Year	11,612

Q. WHAT CAUSES THE FLUCTUATIONS IN THESE COSTS FROM YEAR TO YEAR?

A. The FAS 112 self-insured costs fluctuate from year to year because of changes to the discount rate or demographic adjustments, such as changes in the number of disabled employees or changes in the amount of the average monthly disability benefit. Discount rate changes and demographic adjustments are the differences between actual experience and assumed experience and are recorded in the current year, which can result in significant changes in costs from one year to the next. The slightly higher LTD costs in 2023 and 2024 are due to normal operation of the LTD plan in the actuarial forecasts. In the forecast the Company is expecting the cost to increase as the change in liability is less than the expected benefit payments. Under the FAS 112 LTD accounting methodology, the full impact of the discount rate change is reflected in the year of the update which would have been included in the 2023 forecast. In 2023 the Company increased the discount rate from 2.93 percent to 5.80 percent, which resulted in LTD income, however the income from this change was less than the factors that reduced the 2022 cost. It is reasonable to assume no further changes to the FAS 112 discount rate (level discount rate of 5.80 percent) because our assumptions are the most reasonable estimate to determine 2024 costs at this point in time.

Q. WILL THE COMPANY PROVIDE AN UPDATED FAS 112 DISCOUNT RATE TO INCORPORATE THE MOST RECENT MEASUREMENT DATE?

A. Yes. As we have done in prior rate cases, the Company will provide updated FAS 112 costs in Rebuttal Testimony to incorporate the most recent measurement date of December 31, 2023, which will be available in late January or early February of 2024.

Q. HAS THE COMPANY INVESTIGATED WHETHER IT SHOULD USE ONLY FULLY INSURED PLANS?

A. Yes. The Company has evaluated fully insuring the plans that are currently self-insured, but we determined that it was more costly to fully insure them than to self-insure them due to the small number of individuals covered and the degree of uncertainty around anticipated claims.

Q. HAS THE COMPANY PROVIDED THE ACTUARIAL STUDY AND DERIVATION OF THE JURISDICTIONAL AMOUNT?

A. Yes. Schedule 7, which is an actuarial study that supports the FAS 112 LTD costs for 2024. Schedule 8 shows the conversion of the 2024 total cost amounts to the NSPM gas O&M, State of Minnesota amount.

C. Retiree Medical and FAS 112 Long-Term Disability Benefits Summary

Q. PLEASE SUMMARIZE THE COMPANY'S REQUEST REGARDING THE TEST YEAR AMOUNTS FOR THESE TWO BENEFITS.

A. The Company requests that the Commission approve retiree medical expense in the amount of $220,703. The Company requests that the Commission approve FAS 112 long-term disability benefit expense in the amounts of $11,362 for 2024.

Q. IS IT REASONABLE TO ASK CUSTOMERS TO PAY FOR RETIREE MEDICAL AND FAS 112 LONG-TERM DISABILITY BENEFIT COSTS?

A. Yes. It is appropriate that customers pay for these benefits because they reflect a reasonable and necessary level of expense, and because these are commitments that the Company made to employees who provided quality service to NSPM customers for many years. Stated differently, the FAS 106 and 112 expenses represent benefits that our former employees have already earned, and the Company is required to comply with its obligations to disabled and retired employees. These expenses are akin to accounts payable, which are amounts the Company must pay to satisfy its legal obligations.

VII. EMPLOYEE BENEFIT ASSETS AND LIABILITIES

Q. WHAT TOPIC DO YOU DISCUSS IN THIS SECTION OF YOUR TESTIMONY?

A. I discuss the proposed ratemaking treatment of the Company's prepaid pension asset and its unfunded benefit-related liabilities. In particular, I provide an overview of the prepaid pension asset and explain its value to employees and customers – both in terms of compensating employees who provide service to customers, and to reduce the annual pension expense paid by customers. I also address the Commission's decision in the Company's recent electric rate case to affirmatively remove the electric portion of the prepaid pension asset from rate base.

A. Overview of the Prepaid Pension Assets

Q. PLEASE DESCRIBE THE COMPANY'S PREPAID PENSION ASSET AND ITS ACCRUED RETIREE MEDICAL AND POST-EMPLOYMENT BENEFIT LIABILITY.

A. The prepaid pension asset arises in connection with the Company's qualified pension plan.[5] Over the life of that plan, the Company has contributed more dollars to the plan than it has recognized in actuarially calculated pension expense. This results in a prepaid pension asset. Conversely, the Company has recognized more retiree medical, non-qualified pension and post-employment benefits expense than it has contributed to those plans, which results in accrued liabilities.

Q. WHAT DO YOU MEAN WHEN YOU REFER TO THE ACTUARIALLY CALCULATED EXPENSE THAT IS COMPARED TO THE CUMULATIVE CONTRIBUTIONS BY THE COMPANY?

A. As I discussed earlier in my testimony, the annual qualified pension expense is calculated in accordance with FAS 87 and the ACM. Similarly, the retiree medical costs are calculated under FAS 106, and post-employment benefits are calculated under FAS 112. Based on its accounting records, the Company can quantify the total amount of actuarially calculated expense for each of those benefits over the entire period that the Company has offered that benefit. If that cumulative expense amount is less than the cumulative contributions made

[5] In general, a "prepaid" asset (like the prepaid pension asset) arises when cash is paid in advance of a given service being rendered or benefit being used or realized – i.e., before or in excess of the expense incurred.

by the Company since it began offering that benefit, the Company has a prepaid pension asset. If the cumulative recognized expense exceeds the cumulative contributions to the plan, there is an Accrued but Not Paid Contribution (Accrued Liability).

Q. CAN YOU PROVIDE A CONCRETE EXAMPLE OF HOW A PREPAID PENSION ASSET ARISES?

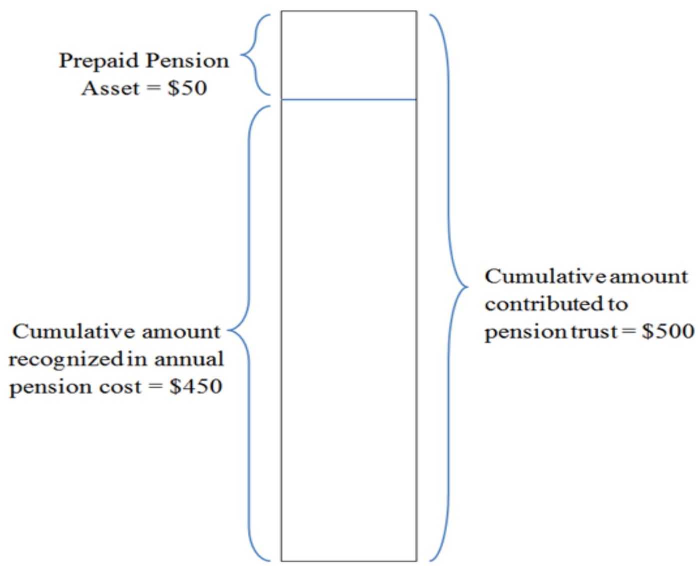
A. Yes. Suppose that the Company contributes $100 per year to the qualified pension trust for each of the first five years of its existence. Further suppose that the actuarially determined qualified pension expense in each of those five years is $90. Table 10 below shows how the excess contributions each year create a cumulative prepaid pension asset.

Table 10
Prepaid Pension Asset Example

Year	Pension Contribution	Pension Expense	Cumulative Prepaid Pension Asset
1	$100	$90	$10
2	$100	$90	$20
3	$100	$90	$30
4	$100	$90	$40
5	$100	$90	$50

At the end of the five-year period, the utility has a prepaid pension asset of $50. Of course, the opposite can also occur. If pension expense exceeds the pension contributions in a given year, the prepaid pension asset will decline, or if there is no prepaid pension asset, the utility may have a pension liability. Over the long run, pension contributions and pension expense will even out, but over the short and intermediate run there will almost certainly be differences, which are recorded as prepaid pension assets or pension liabilities. Figure 1[6] below visually depicts the prepaid pension asset as the excess contributions over the recognized pension expense.

Figure 1



Q. WHY ARE THE CONTRIBUTIONS AND EXPENSE DIFFERENT IN ANY GIVEN YEAR?

A. As I discussed earlier, the qualified pension expense calculation is governed by the ACM and FAS 87, which sets forth the rules that companies must follow in determining their pension costs in order to have their accounting be acceptable under GAAP. In contrast, the contributions are driven by federal law requirements under ERISA and the IRC, such that the Company has little to no discretion regarding its funding obligations for the pension fund. Although the expense and contribution calculations both use accrual methodologies, the assumptions, attribution methods, and periods of time over which the costs are

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[6] The amounts in this figure are merely illustrative, as are the amounts in Table 10.

required to be recognized are different and thus can often result in different annual amounts.

Q. CAN THE UTILITY WITHDRAW THE PREPAID PENSION ASSET AND USE IT TO FUND CAPITAL REQUIREMENTS OR TO PAY FOR OPERATION AND MAINTENANCE EXPENSE?

A. No. As I noted earlier in my discussion of the calculation of qualified pension expense, federal law prohibits the withdrawal of any amounts from the pension trust fund except for the payment of benefits and plan expenses. Once the contributions are made, they are locked away.

Q. HOW DOES THE PREPAID PENSION ASSET RELATE TO THE FUNDED STATUS OF THE PENSION TRUST?

A. Fundamentally, the prepaid pension asset and the funded status of the pension trust measure different things. The funded status of the pension trust measures whether the pension trust currently has enough assets to pay all of its accumulated obligations to plan beneficiaries into the future. If the pension trust does not have enough assets to pay all accumulated obligations to plan beneficiaries, the plan is underfunded; conversely, if the pension trust has more than enough assets to pay all of its accumulated obligations to plan beneficiaries, the plan is overfunded. The funded status is illustrated in Table 11 below. On the other hand, the prepaid pension asset simply measures the extent to which the Company has contributed more to the plan than it has recognized in pension benefits expense to date. While related, the concepts are fundamentally different.

The Financial Accounting Standards Board enacted FAS 158 in 2006, to require that the funded status of the plan and the events affecting the funded status of the plan be more clearly illustrated in a Company's financial statements. Although FAS 158 de-emphasized financial statement reporting on the prepaid pension asset or unfunded pension liability, nothing in FAS 158 indicates that a prepaid pension asset no longer exists or should be written off. Thus, the pension trust can have a prepaid pension asset at the same time the future obligations are not fully funded.

Q. IS THERE OTHER PHYSICAL PROOF OF THE EXISTENCE OF THE PREPAID PENSION ASSET AND ITS COMPLIANCE WITH GENERALLY ACCEPTED ACCOUNTING PRINCIPLES?

A. Yes. Both the contribution and expense amounts are also publicly disclosed in the Company's annual 10-K filings with the SEC. The prepaid pension asset also appears on the Company's balance sheet, is supported by the Company's actuaries, and is included in annual audits performed by the Company's outside accounting firm.

Q. HOW DOES THE PREPAID PENSION ASSET APPEAR ON THE COMPANY'S BALANCE SHEET?

A. On the balance sheet, $222 million is the beginning balance of the prepaid pension asset net of ACM for the 2023 forecast. The prepaid pension asset represents the sum of: (1) the Company's total unrecognized asset or liability gains or losses,[7] and (2) the funded status of the pension trust. Both of those amounts appear on the balance sheet, and this is simply a different way of portraying the difference between cumulative contributions and cumulative

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[7] I described asset and liability gains and losses earlier in my Direct Testimony.

expense. Indeed, it is possible to quantify the prepaid pension asset of any company that has a defined benefit pension plan by adding those two numbers from the balance sheet, and this amount is disclosed in our annual 10-K filing for NSPM.

Q. CAN YOU SHOW WHERE THE PREPAID PENSION ASSET AMOUNT APPEARS IN THE NSPM 10-K FILING FOR 2022?

A. Yes. The prepaid pension asset can be derived by adding two numbers included in Footnote 9 – Benefit Plans and Other Postretirement Benefits: (1) the "Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost (i.e., the Net Loss) on page 47 of the NSPM 10-K, and (2) the funded status, which can be found on page 46 of the NSPM 10-K. The amounts and tables included in the screenshot below can be found in the NSPM 2022 10-K filing, included as Exhibit___(RRS-1), Schedule 9.

Table 11

	Pension
(Millions of Dollars)	**2022**
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:	
Net loss	$ 309
Prior service credit	—
Total	$ 309
Funded status of plans at Dec. 31	$ (87)

As noted above, these two amounts added together ($309 million – $87 million = $222 million (rounded)) represent the total NSPM prepaid pension asset as of December 31, 2022. This amount is then allocated to the Minnesota gas jurisdiction, to arrive at an NSPM Minnesota Gas jurisdictional balance of $14,510,284.

Q. CAN YOU TIE THE NSPM DISCLOSED PREPAID PENSION ASSET AMOUNT OF $222 MILLION TO THE TOTAL MINNESOTA GAS PREPAID PENSION ASSET THAT WAS FILED IN THIS CASE?

A. Yes. See the table below for a reconciliation of the prepaid pension asset included in Exhibit___(RRS-1), Schedule 10, Prepaid Pension Asset Support Calculation, to the prepaid pension asset included above in the 2021 10-K filing.

Table 12
(Amounts in Millions, rounded to nearest million)

Description	12/31/2022	Comments
GAAP Prepaid Pension Asset	$222	Ties to 10-K
ACM - Regulatory Liability Offset	(34)	
Prepaid Pension net of Reg Offset	$188	Amount ties to Line 6 of Exhibit RRS - Schedule 10

As shown in Schedule 10, the $188 million is the beginning balance of the prepaid pension asset net of ACM for the 2023 forecast. The 13-month prepaid pension asset is further allocated down to the Minnesota Gas amount as evidenced in Schedule 10.

Q. ARE THESE DISCLOSURE REQUIREMENTS REQUIRED FOR EVERY COMPANY WITH A DEFINED BENEFIT PENSION PLAN?

A. Yes.

Q. CAN YOU FIND THE ANNUAL AMOUNT OF THE PREPAID PENSION ASSET IN THE ANNUAL 10-K FILING FOR EVERY PUBLICLY TRADED COMPANY THAT HAS A DEFINED BENEFIT PENSION PLAN, REGULATED OR UNREGULATED?

A. Yes.

Q. IF THE PENSION PLAN IS NOT FULLY FUNDED AS ILLUSTRATED ABOVE, DOESN'T THAT INDICATE THERE IS A NET LIABILITY WITH RESPECT TO PENSION OBLIGATIONS, REGARDLESS OF ANY CASH SET ASIDE TO PARTIALLY FUND THE PLAN?

A. No. As I discuss above, the funded status and the prepaid pension asset are two different things. Both are on the 10-K as shown in Table 12 above, with the prepaid pension asset equivalent to the net of the funded status and the net loss. Further, the pension trust can be either fully funded or less than fully funded and a prepaid pension asset can still exist, as is the case when the cash contributed by the Company to achieve the trust's funded status has not yet been recognized as an expense, and indeed has not been expensed because the relevant employees have not yet completed their service. Fundamentally, it is necessary to include the prepaid pension status in rate base in order for rates to fully and fairly reflect proper pension accounting.

Q. CAN YOU PROVIDE SPECIFIC EVIDENCE OF THE ANNUAL CUMULATIVE CONTRIBUTIONS AND CUMULATIVE EXPENSE AMOUNTS THAT, WHEN NET AGAINST EACH OTHER, MAKE UP THE NSPM PREPAID PENSION ASSET?

A. Yes. Exhibit ___ (RRS-1), Schedule 11, Cumulative Contribution and Expense Pension Support, as summarized in Table 13 below, shows the actual total NSPM prepaid pension asset balance as of December 31, 2022,[8] and all the

[8] This schedule also includes forecasted information for calendar year 2023.

contributions and expense amounts that make up the $187.7 million NSP prepaid pension asset exclusive of the ACM.

Table 13
NSPM Prepaid Pension Asset Contributions and Expenses

Year	Beginning Asset (Liability) Balance	Recognized Expense	Cash Contributions	Other	Ending Asset (Liability) Balance
2009					(20,181,500)
2010	(20,181,500)	(6,481,000)	20,182,000	-	(6,480,500)
2011	(6,480,500)	(12,728,000)	41,375,000	-	22,166,500
2012	22,166,500	(28,981,000)	79,584,333	(1,080,000)	71,689,833
2013	71,689,833	(41,706,000)	72,411,729	-	102,395,562
2014	102,395,562	(38,911,000)	52,114,844	-	115,599,406
2015	115,599,406	(34,213,000)	32,734,611	-	114,121,017
2016	114,121,017	(33,981,000)	49,429,675	-	129,569,692
2017	129,569,692	(34,862,000)	60,740,655	(620,000)	154,828,347
2018	154,828,347	(34,465,000)	63,147,000	-	183,510,347
2019	183,510,347	(34,707,000)	46,817,855	-	195,621,202
2020	195,621,202	(31,384,000)	43,959,000	-	208,196,202
2021	208,196,202	(31,811,000)	34,109,000	(369,000)	210,125,202
2022	210,125,202	(27,379,000)	4,907,000	-	187,653,202
2023	187,653,202	(30,377,000)	23,279,000	-	180,555,202

The contributions are each supported by copies of individual bank statements provided by the Company's bank, and the annual expense amounts are supported by copies of actuarial supporting documents. The Summary tab of this Schedule (page 1) adds the contributions and nets them against the expenses to show that the cumulative actual cash contributions by NSPM substantially exceed the cumulative annual pension expense, creating the prepaid pension asset. As I discuss throughout this testimony, the Company no longer has access to the funds for any other purpose once they are deposited in the trust.

Q. ARE THE COMPANY'S FINANCIAL STATEMENTS SHEETS AUDITED BY OUTSIDE AUDITORS?

A. Yes. The Company's financial statements are audited annually by Deloitte.

Q. HAS DELOITTE EVER CONCLUDED THAT THE COMPANY FAILED TO COMPLY WITH GAAP BY CONTINUING TO REFLECT A PREPAID PENSION ASSET ON ITS BALANCE SHEET?

A. No. If the prepaid pension asset was not in compliance with GAAP, it is inconceivable that Deloitte would have allowed the Company to continue reflecting the amounts that comprise the prepaid pension asset on its balance sheet for the past 15 years. Deloitte also investigates whether the Company is complying with regulatory requirements. Deloitte has repeatedly provided a clean audit opinion in all material respects for each of these years.

In sum, there are multiple forms of clear physical, verified evidence that the Company has made cumulative contributions in excess of cumulative expense to the pension fund.

B. Ratemaking Treatment of Prepaid Pension Asset

Q. HOW ARE PREPAYMENTS AND ACCRUED LIABILITIES GENERALLY TREATED FOR PURPOSES OF SETTING RATES?

A. Prepayments by the utility are generally treated as an addition to rate base, whereas prepayments by customers (Accrued Liabilities) are generally treated as a reduction to rate base.

Q. IS THE COMPANY PROPOSING TO APPLY THE STANDARD RATEMAKING TREATMENT OF PREPAYMENTS AND ACCRUED LIABILITIES IN THIS CASE?

A. Yes. In this case, the Company is proposing to include the Company's prepayments of pension expense as an addition to rate base, and to treat the customers' prepayments of FAS 106 and FAS 112 as a reduction to rate base. Because the prepaid pension asset is larger than the Accrued Liabilities, the Company has a net asset and therefore has an increase to rate base. The Company proposes to earn a return on the asset at the Company's weighted average cost of capital (WACC).

Q. IS THE COMPANY PROPOSING TO EARN A RETURN ON THE FULL AMOUNT OF THE NET PREPAID PENSION ASSET?

A. No. The net amount of the asset will be further offset by the ADIT associated with it. Thus, instead of earning a return on the full amount of the net asset (i.e., the prepaid pension asset less the accrued liabilities of retiree medical and post-employment benefits) the Company earns a return only on the portion that remains after the ADIT is subtracted from it.

Q. HOW DOES ADIT ARISE IN CONNECTION WITH THE PREPAID PENSION ASSET OR ACCRUED LIABILITY?

A. When the Company makes a contribution, it is allowed to deduct the contribution amount (up to IRS-imposed limits). That deduction shields income from taxes, which gives rise to deferred taxes. Thus, the amount by which the contributions in a particular year exceed the annual recognized cost for that year gives rise to a deferred tax liability. The opposite situation occurs when the annual cost recognized for a particular benefit exceeds the contribution, which give rise to a deferred tax asset. Company witness Halama discusses ADIT and how it impacts our filing.

Q. WHAT AMOUNT OF BENEFIT ASSETS AND LIABILITIES IS INCLUDED IN THE TEST YEAR RATE BASE?

A. Table 14 below shows the amount included in rate base for all benefit types in the test year. This table also shows the amounts that must be offset by the ADIT associated with the benefit asset or liability balance. This same information can also be found in the non-plant rate base information provided by Company witness Halama. The net balance is approximately $8.7 million on a Minnesota gas jurisdictional basis. This amount should be added to the Company's rate base because it represents investor (shareholder) capital held for future use and because it will reduce ratepayer costs in those years, providing ratepayer benefit.

Table 14
Pension and Benefits Assets and Liabilities ($)

Rate Base Benefit (Short and Long-Term)	Non-Plant Rate Base Asset/(Liability)	Associated Accumulated Deferred Tax Asset/(Liability)	Net Rate Base Impact Asset/(Liability)
Prepaid Pension Asset	14,608,155	(4,086,164)	10,521,991
Retiree Medical - FAS 106	(1,904,090)	532,608	(1,371,482)
Post-Employment Benefits FAS 112	(618,498)	173,005	(445,493)
Total	**12,085,585**	**(3,380,551)**	**8,705,016**

Q. WHAT IS THE COMPANY'S REQUEST WITH RESPECT TO THE NET PENSION ASSET BALANCE OF $8.7 MILLION?

A. The Company seeks Commission approval to add that amount to its rate base and earn its WACC on that balance, consistent with the treatment of other prepayments.

Q. HAS THE COMPANY CREATED A SCHEDULE TO REFLECT THE UNDERLYING CALCULATION OF THE PREPAID PENSION ASSET THAT IS INCLUDED IN THE 2024 TEST YEAR?

A. Yes. Schedule 10 shows the annual calculation of the total NSPM prepaid pension asset or liability from 2017 through 2024. Schedule 10 also shows a detailed calculation by month that supports the 2023-2024 NSPM gas State of Minnesota prepaid pension asset balances that are being requested in rate base for this case.

Q. WHAT HAS CAUSED THE GROWTH OF THE PREPAID PENSION ASSET?

A. The growth of the prepaid pension asset was driven by two factors, both of which were outside the Company's control. The first factor was the enactment by Congress of the Pension Protection Act of 2006. Prompted by the defaults by several large defined benefit pension plans in the early part of that decade, Congress passed legislation that gave defined benefit pension plans seven years to become 100 percent funded. The Pension Protection Act also created penalties for plans that are underfunded, including an increase in Pension Benefit Guaranty Corporation (PBGC) premiums. As I will explain in more detail later in my testimony, the PBGC was established by Congress to ensure pension benefits under private-sector defined benefit pension plans. The PBGC is funded by premiums paid by plan sponsors and by investment returns on the assets held in the PBGC trust fund.

The second factor was the reduction in interest rates, which was caused by the Federal Reserve's efforts to stimulate the national economy in the wake of the 2008 recession. The resulting drop-in discount rates caused the Company's pension liabilities to become larger, which increased the amount of underfunding. This is because future pension liabilities are discounted to present value, and a higher discount rate reduces the liability balance, whereas a lower discount rate increases the liability balance. That liability balance is then compared to the value of the trust assets to determine its funded status and to determine whether the trust is overfunded or underfunded. The reduction in interest rates also required the Company to set aside more cash contributions, which, when combined with the other factors highlighted above, contributed to a growth in the prepaid pension asset.

Q. HOW DID THE COMPANY RESPOND TO THE COMBINATION OF HEIGHTENED FUNDING REQUIREMENTS AND A LOWER FUNDING LEVEL IN ITS PLANS?

A. The Company responded by taking the only steps that were practically available to it, which was to provide additional funding to the pension plans. To help ensure that the pension plans complied with the Pension Protection Act by becoming fully funded within seven years, the Company made the contributions listed in Schedule 10 and Schedule 11. As I mentioned previously, these contributions will be recognized as expense over future periods, aligning with the timing Company employees are providing service. This timing difference gives rise to the prepaid pension asset.

Q. IS THE COMPANY ALSO INCLUDING THE FUNDED STATUS, AS AN UNFUNDED LIABILITY THAT REDUCES THE RETURN, IN RATE BASE?

A. Yes. As described above, this $87 million (Total Company) is also in rate base but is a separate component of total pension accounting. It does not replace the prepaid pension asset. It is therefore necessary to also include the prepaid pension asset in rate base in order to arrive at correct and balanced treatment of all components of pension costs.

C. Justification for Including the Net Asset in Rate Base

Q. WHY IS IT APPROPRIATE TO INCLUDE THE NET ASSET IN RATE BASE?

A. The net asset should be included in rate base for three separate and independent reasons. First, as I explained earlier, it is a well-established regulatory principle for prepayments to be included in rate base, regardless of whether they are prepayments by the utility or by its customers. This is because the prepayment reflects a timing difference between when the Company pays (prepays) an amount and when customers contribute to the cost of that item, and a return on the asset or liability compensates the pre-paying party for providing those funds. There is no reason to treat the net pension prepayment in this case differently. Second, having an adequately funded pension plan helps attract and retain the employees who provide safe and reliable gas service to our customers. Therefore, the prepaid pension asset is just that – an asset established by Company cash contributions – and the Company should earn a return on that asset, just as it earns a return on other assets. Third, customers are receiving the benefit of a return on the prepaid pension asset, and therefore it is appropriate that the Company earn a return on its prepayment as well.

Q. PLEASE EXPLAIN WHAT YOU MEAN WHEN YOU STATE THAT CUSTOMERS ARE RECEIVING THE BENEFIT OF A RETURN ON THE PREPAID PENSION ASSET.

A. As I explained earlier in my testimony, the annual pension cost determined under both accounting methods, the ACM (NSPM Plan) and FAS 87 (XES Plan), includes an EROA. The EROA percentage is multiplied by the value of the assets in the pension trust, and the product of that calculation is subtracted from the annual pension cost. Thus, the return on the prepaid pension asset reduces the annual qualified pension cost passed on to ratepayers on a dollar-for-dollar basis.

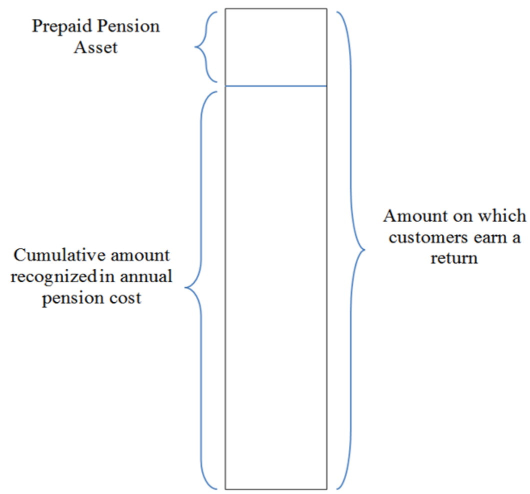
Q. WHAT IS THE EROA FOR THE NSPM PLAN AND THE XES PLAN?

A. The EROA for both the NSPM Plan and the XES Plan is 7.25 percent for 2024. That percentage is applied to the balance in the pension trust.

Q. DOES THE PENSION TRUST FUND BALANCE THAT IS MULTIPLIED BY THE EROA INCLUDE THE PREPAID PENSION ASSET?

A. Yes. As shown in Figure 2 below (a simplified reproduction of Figure 1 earlier in my Direct Testimony), customers receive the benefit of the earnings on the *entire* amount of assets in the pension trust, not just the amount that has been recognized in annual pension cost.

Figure 2



As the figure shows, customers are receiving the benefit of market returns on investments made by the Company in the pension trust that customers have not yet paid for through recognized pension cost. In effect, the Company has made a prepayment of pension contributions, and customers are earning a return on that prepayment at the EROA. The return is reflected as a decrease in annual pension cost. It would be inequitable and unreasonable to deny the Company a return on the prepaid pension asset at the WACC because customers are, in fact, receiving the benefit of a return on that prepayment at the EROA.

Q. WHY IS IT APPROPRIATE TO APPLY THE WACC AS THE RATE OF RETURN ON THE PREPAID PENSION ASSET?

A. First and foremost, the prepaid pension asset is a utility asset funded by NSPM that directly supports providing utility service – in this case, by enabling payment of valuable retirement benefits to utility employees. For this reason alone, the Company is entitled to an opportunity to earn a reasonable return on the service-producing asset, which is the authorized WACC established by the Commission. The authorized WACC that is applied to the other assets and liabilities to reflect that the Company finances its business with a combination of debt and equity should likewise apply to this asset.

In addition, the balance of the prepaid pension asset earns market returns (the EROA) that directly reduce the annual expense paid by customers through rate. This is an advantage to customers provided by the prepaid pension asset that does not apply to most other service-producing assets. Indeed, the NSPM pension plan balance on which customers earn a return is much larger than the balance on which the Company is proposing they pay a return. Additionally, customers earn a return on the XES prepaid pension asset, but do not pay a return on that asset because it is not included in rate base for ratemaking purposes.[9] Also, the prepaid pension asset allows the Company to avoid paying incremental PBGC premiums that would be added to the pension expense paid by customers in the absence of the prepaid pension asset. For all these reasons, it is appropriate to apply a WACC return to the prepaid pension asset.

Q. PLEASE EXPLAIN FIRST WHY IT MATTERS THAT THE BALANCE OF THE NSPM PREPAID PENSION ASSET ON WHICH CUSTOMERS EARN A RETURN IS MUCH LARGER THAN THE BALANCE ON WHICH THEY HAVE HISTORICALLY PAID A RETURN.

A. The 7.25 percent EROA is applied to the full amount of the NSPM prepaid pension asset, which totals approximately $13.6 million for the gas department. As shown in Table 14, that reduces the pension expense included in rates by more than $1.2 million per year. In contrast, the Company is proposing that customers pay a 7.48 percent return on only $8.3 million because the amount

[9] NSPM does not include the XES prepaid pension asset in rate base because the asset belongs to XES, not to NSPM.

included in rate base reflects reductions for ADIT and the unfunded FAS 106 and FAS 112 liabilities. Thus, the balance on which customers earn a return is far larger than the balance on which they pay a return.

Q. WHAT IS THE BALANCE OF XES PREPAID PENSION ASSET ON WHICH CUSTOMERS EARN A RETURN BUT DO NOT PAY A RETURN?

A. The thirteen-month average balance of the XES Plan net prepaid pension asset associated with NSPM's gas retail jurisdiction will be approximately $2.3 million in 2024. With an EROA of 7.25 percent for the XES Plan, NSPM's gas retail customers will receive the benefit of approximately $0.2 million (gas retail) of market returns on an asset on which they pay no return. That reduces annual pension expense by an equal amount.

Q. HAS THE COMPANY QUANTIFIED THE REDUCTION IN ANNUAL PENSION EXPENSE THAT CUSTOMERS EXPERIENCED AS A RESULT OF THE PREPAID ASSETS?

A. Yes. As shown in Table 15, the Company's qualified pension expense will be reduced by $1.2 million in 2024 on a gas basis because of earnings on prepaid pension assets:

Table 15
Amounts are NSPM Gas State of MN (2024 13-month Average)

Pension Plan	Prepaid Pension Asset Balance	EROA	Rate Reduction from Prepaid Pension Asset
NSPM	$14,608,155	7.25%	$1,059,091
XES	$2,289,167	7.25%	$165,965
Total	**$17,058,841**		**$1,236,766**

Thus, the earnings on the prepaid pension asset will reduce the Company's revenue requirement by nearly $1.2 million in 2024. Because that reduction is passed through to customers on a dollar-for-dollar basis, NSPM's Minnesota retail customers realize a substantial benefit as a result of the prepaid pension asset.

Q. CAN YOU FURTHER EXPLAIN HOW THE PREPAID PENSION ASSET BENEFITS CUSTOMERS BY REDUCING PBGC PREMIUMS?

A. Yes. As I noted earlier, the contributions that helped create the prepaid pension asset allow the Company to avoid incurring PBGC premiums that would otherwise be included within the annual pension cost charged to customers.

Q. PLEASE DESCRIBE THE PBGC.

A. The PBGC is a federal agency established by Congress as part of ERISA to insure pension benefits under private sector defined benefit pension plans. If a pension plan is terminated without sufficient money to pay all benefits, PBGC's insurance program will pay employees the benefits promised under the pension plan, up to the limits set by law. The funding for the PBGC comes partly from premiums charged to pension sponsors and partly from returns on assets held by the PBGC.

Q. WHAT TYPES OF PREMIUMS DOES THE PBGC CHARGE?

A. The PBGC charges two types of premiums: (1) a per capita premium that is charged to all single-employer defined benefit plans; and (2) a variable premium charged to underfunded plans. The amounts of the premiums are set by Congress and must be paid by sponsors of the defined benefit plans, such as NSPM.

Q. ARE THE VARIABLE PREMIUMS APPLICABLE TO UNDERFUNDED PLANS INCREASING?

A. Yes. For 2023, the variable-rate premium for a single-employer plan such as that of NSPM will be $52 per $1,000 of unfunded vested benefits.

Q. ARE PBGC PREMIUMS INCLUDED IN THE ANNUAL PENSION COST?

A. Yes. PBGC premiums are included in the annual pension cost calculation, but the existence of the prepaid asset reduces the PBGC premiums for NSPM's gas retail customers. Thus, in addition to the net benefit created by the market returns on Company contributions reducing pension expense, customers avoid PBGC premiums that are paid via market returns on the prepaid pension asset. Maybe most importantly, an asset supporting utility service to customers (in this case by attracting and retaining qualified employees and compensating them for work performed on behalf of customers) is already entitled to a reasonable return, independent of any cost reduction benefits created by that asset. In essence, the cost reduction benefits created by the prepaid pension asset are ancillary benefits that further bolster why it is appropriate and necessary to include the net asset in rate base and for the Company to earn a WACC return on the asset.

Q. PLEASE SUMMARIZE THE COMPANY'S REQUEST WITH RESPECT TO THE PREPAID PENSION ASSET.

A. The Company requests that the prepaid pension asset be included in rate base. That is how other prepayments are treated, including prepayments by customers, and there is no reason to treat the prepaid pension asset differently. Moreover, customers realize a significantly greater rate reduction from the prepaid pension asset than the return they are asked to pay, so it is reasonable and equitable for the prepaid pension asset to be included in rate base and to earn a WACC return.

D. WACC Return on Prepaid Pension Asset in Every Other Xcel Energy Jurisdiction

Q. DO XCEL ENERGY OPERATING COMPANIES IN OTHER JURISDICTIONS EARN A RETURN ON THEIR PREPAID PENSION ASSETS?

A. Yes. Every other Xcel Energy operating company in every other jurisdiction in which we provide utility service earns a return on their prepaid pension assets. While this has not been a contested issue in all of these jurisdictions, in those where it has, courts and regulatory jurisdictions have unanimously allowed the applicable Xcel Energy operating companies to include their prepaid pension assets in rate base and to earn a return on them. I am familiar with the decisions in those jurisdictions because I have been the Xcel Energy operating company's pension witness in all jurisdictions.

Q. IN WHICH JURISDICTIONS OUTSIDE MINNESOTA HAVE XCEL ENERGY'S OTHER OPERATING COMPANIES' PREPAID PENSION ASSET BEEN EXPLICITLY ADDRESSED BY REGULATORY COMMISSIONS OR COURTS?

A. I am aware of applicable decisions in Colorado, New Mexico, and Texas.

Q. PLEASE DESCRIBE HOW THE ISSUE HAS BEEN ADDRESSED IN COLORADO.

A. In a 2017 gas rate case, the Colorado Public Utilities Commission (CPUC) denied the request of Public Service Company of Colorado (Public Service or PSC), NSPM's sister company, to include its prepaid pension asset in rate base.[10]

[10] *In the Matter of Advice Letter No. 912-Gas Filed by Public Service Company of Colorado to Roll the Pipeline System Integrity Adjustment ("PSIA") Costs Into Base Rates Beginning in 2019 and Increase Rates for All Natural Gas Sales*

Public Service appealed the CPUC's decision to state district court. In a decision that was issued in March 2020, the court reversed the CPUC and concluded that Public Service had a constitutional right to earn a return on its prepaid pension asset because the prepaid pension asset was no different from other assets used by the utility to provide service:

> [T]he evidence was undisputed that this defined-benefits pension plan contributed to the service-producing activities of PSC. Any prepayments therefore likewise contributed to the service-producing activities of PSC. Because PSC is constitutionally entitled to a reasonable return on its service-producing assets, it is constitutionally entitled to a reasonable return on its prepayments.[11]

The case was then remanded to the CPUC for implementation, at which time the CPUC applied a WACC return to the prepaid pension asset.[12] Since that time, Public Service has earned a WACC return on its prepaid pension asset in both its electric and gas rate cases.[13]

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and Transportation Services by Implementing a General Rate Schedule Adjustment ("GRSA") in the Company's Colorado P.U.C. No. 6-Gas Tariff, to Become Effective July 3, 2017, Decision No. C1800736-I at ¶ 104 (Mailed Aug. 29, 2018).

[11] *Public Service Company of Colorado v. The Public Utilities Commission of the State of Colorado*, Case No. 19CV31427, Order at 18 (Denver County District Court, Mar. 12, 2020). The Colorado commission did not appeal the district court decision to the Colorado Supreme Court.

[12] *In the Matter of Advice Letter No. 912-Gas Filed by Public Service Company of Colorado to Roll the Pipeline System Integrity Adjustment ("PSIA") Costs Into Base Rates Beginning in 2019 and Increase Rates for All Natural Gas Sales and Transportation Services by Implementing a General Rate Schedule Adjustment ("GRSA") in the Company's Colorado P.U.C. No. 6-Gas Tariff, to Become Effective July 3, 2017*, Decision No. C21-0406 at ¶¶ 26–27 (Mailed July 12, 2021).

[13] *In the Matter of Advice Letter No. 1906 - Electric Filed by Public Service Company of Colorado to Revise its Colorado P.U.C. No. 8 – Electric Tariff to Increase Base Rate Revenues, Implement new Base Rates for All Electric Rate Schedules, and Make Other Tariff Changes, to Become Effective December 31, 2022*, Decision No. C23-0592 at ¶ 54 (Mailed September 6, 2023); *In the Matter of Advice Letter No. 993-Gas of Public Service Company of Colorado to Revise its Colorado P.U.C. No. 8 – Gas Tariff to Increase Jurisdictional Base Rate Revenues, Implement New Base Rates for All Gas Rate Schedules, and Make Other Proposed Tariff Changes to Become Effective February 24, 2022*, Decision No. C22-0642 at ¶ 187 (Mailed October 25, 2022).

Q. IS THE PREPAID PENSION ASSET OF NSPM ALSO A "SERVICE-PRODUCING ASSET," AS THAT TERM WAS USED BY THE COLORADO COURT?

A. Yes. The Colorado court found that Public Service's prepaid pension asset was a service-producing asset because it helped reduce rates for customers and because it helped Public Service attract and retain employees. In addition, the court found it significant that Public Service was required by federal law to maintain a certain funding level for the pension plan. As discussed above, all of those things are true of NSPM's prepaid pension asset as well.

Q PLEASE DESCRIBE HOW THE PREPAID PENSION ASSET HAS BEEN TREATED IN NEW MEXICO.

A. In a 2014 order, the New Mexico Public Regulation Commission allowed SPS to include its prepaid pension asset in rate base and to earn a return on it. The New Mexico Attorney General appealed that issue to the New Mexico Supreme Court, which upheld the New Mexico commission's decision to include the prepaid pension asset in rate base:

> It is uncontested that SPS investors made contributions to the pension fund that are required by law. These contributions exceeded expenses and generating earnings that effectively reduced SPS's – and consequently the ratepayers' – pension expense. Had the ratepayers advanced the contributions to the pension fund, their contributions would not have been included in rate base. [Citation omitted]. However, because the ratepayers did not make the contributions, the investors, not the ratepayers, absorbed the cost of funding the pension program, and therefore the net prepaid pension asset was property included in the rate base.[14]

[14] *New Mexico Attorney General v. New Mexico Public Regulation Comm'n*, 2015-NMSC-032 at ¶ 21.

Q. IS THERE ANY MATERIAL DIFFERENCE BETWEEN THE PREPAID PENSION ASSET AT ISSUE IN THE NEW MEXICO CASE AND NSPM'S PREPAID PENSION ASSET?

A. No. Both the SPS and NSPM prepaid pension assets represent investor contributions that reduce the pension expense included in rates and that help attract and retain employees. Therefore, like the SPS asset the NSPM asset should be included in rate base.

Q. PLEASE DESCRIBE HOW THE PUBLIC UTILITY COMMISSION OF TEXAS HAS TREATED SPS'S PREPAID PENSION ASSET.

A. In a 2015 base rate case, parties challenged SPS's request to include its prepaid pension asset in rate base and to earn a WACC return on that asset. The Texas commission rejected those challenges:

> Accounting in accordance with GAAP requires that the amount by which the cash contributions made to the pension trust exceed the accumulated pension cost to be recorded as a prepaid pension asset. Investment income on the prepaid pension asset reduces qualified pension costs calculated under FAS 87, which benefits customers by reducing the amount of pension costs included in base rates. The prepaid pension asset is appropriately included in rate base because it represents a prepayment by SPS.[15]

[15] *Application of Southwestern Public Service Company for Authority to Change Rates*, Docket No. 43695, Order on Rehearing at 23 (Feb. 23, 2016).

Q. IS THERE ANY MATERIAL DIFFERENCE BETWEEN THE PREPAID PENSION ASSET AT ISSUE IN THE TEXAS CASE AND NSPM'S PREPAID PENSION ASSET?

A. No. Just like the New Mexico prepaid pension asset, the Texas prepaid pension asset was created by investor contributions that reduced the pension expense included in rates. The Texas prepaid pension asset also helped SPS attract and retain employees. ll of those things are true of the NSPM prepaid pension asset as well. Therefore, it should be included in rate base.

E. Commission Precedent on Prepaid Pension Asset

Q. WHAT TOPIC DO YOU DISCUSS IN THIS SECTION OF YOUR TESTIMONY?

A. I describe the way the Minnesota Commission has treated the prepaid pension asset in recent cases, and I explain why I respectfully suggest the Commission has reached the incorrect outcome.

Q. HOW HAS THE COMMISSION TREATED THE PREPAID PENSION ASSET IN RECENT RATE CASES?

A. In several recent cases, including the Company's recent Minnesota electric rate case, the Commission has excluded the utilities' prepaid pension assets from rate base and disallowed any return on those assets.[16] I respectfully submit that the reasoning employed by the Commission in those cases is either mistaken – relying on incorrect arguments advanced by the Department of Commerce – or does not apply to NSPM.

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[16] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-002/GR-21-630, Findings of Fact, Conclusions of Law, and Order at 27 (July 17, 2023) (NSPM Electric Order); *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-015/GR-16-664, Findings of Fact, Conclusions and Order at 16 (Mar. 12, 2018) (Minnesota Power Order); *In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota*, Docket No. G-011/GR-15-736, Findings of Fact, Conclusions, and Order at 11 (Oct. 31, 2016) (MERC Order); *In the Matter of Otter Tail Power Company for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-017/GR-15-1033, Findings of Fact, Conclusions, and Order at 25 (May 1, 2017) (Otter Tail Order).

Q. WHAT COMMON REASONS HAS THE COMMISSION ASSERTED TO DENY UTILITIES' REQUESTS TO INCLUDE THEIR PREPAID PENSION ASSETS IN RATE BASE AND TO EARN A RETURN ON THOSE ASSETS?

A. In the Commission's orders in recent cases involving NSPM's electric utility, Minnesota Power, Minnesota Energy Resources Corp. (MERC), and Otter Tail Power Company (Otter Tail), the Commission has rejected requests to include the utilities' pension and benefit-related assets and liabilities in rate base because:

- The prepaid pension asset "is misleading in that it does not account for the funding status of the entire pension plan."[17]
- The "pension-plan assets and benefit obligations go up and down depending on funding, market conditions, or amendments to the plan."[18]
- The prepaid pension asset "fluctuates in value" and the Company's decisions as well as actuarial assumptions, legally required or actual contributions, and market returns can affect the amount and permanence of the prepaid pension asset.[19]
- The "balances in the prepaid pension asset are temporary"[20]
- "Minnesota statutory language directs the Commission's attention to capital property that is acquired by the utility, which depreciates over time, and which is constructed" whereas "Xcel's prepaid pension asset is fundamentally different from capital expenditures and other rate base categories"[21]

[17] NSPM Electric Order at 26.
[18] NSPM Electric Order at 26; Minnesota Power Order at 16; MERC Order at 11; Otter Tail Order at 25.
[19] NSPM Electric Order at 26; Minnesota Power Order at 16.
[20] NSPM Electric Order at 26, 27; Minnesota Power Order at 16; MERC Order at 11; Otter Tail Order at 25.
[21] NSPM Electric Order at 26-27.

- "Xcel has not pointed to any accounting requirements, rules, or laws that require prepaid pension assets to be included in rate base and earn a return"[22];
- In the NSPM electric rate case, the "Department has raised valid concerns about whether Xcel's accounting proposal would be consistent with Generally Accepted Accounting Principles"[23]; and
- The asset already earns a return in the form of investment returns.[24]

Additionally, with respect to other utilities the Commission has found that:

- The utility "recovers its allowable pension expense from ratepayers, and is not being denied recovery of this operating cost"[25];
- It would be "impractical, if not impossible, to equitably separate the prepaid amount attributable solely to [the utility's] contributions from that attributable to ratepayer contributions and market returns."[26]

None of those reasons justifies excluding NSPM's prepaid pension asset from rate base.

[22] NSPM Electric Order at 26.
[23] NSPM Electric Order at 26.
[24] NSPM Electric Order at 26; Minnesota Power Order at 16.
[25] Minnesota Power Order at 16; MERC Order at 11; Otter Tail Order at 25.
[26] Minnesota Power Order at 17.

Q. PLEASE ADDRESS THE SECOND AND THIRD RATIONALE, WHICH ARE THAT PENSION-PLAN ASSETS AND BENEFIT OBLIGATIONS GO UP AND DOWN DEPENDING ON FUNDING, MARKET CONDITIONS, OR AMENDMENTS TO THE PLAN, AND THE PREPAID PENSION ASSET ITSELF FLUCTUATES IN VALUE BASED ON CONTRIBUTIONS, ACTUARIAL ASSUMPTIONS, AND MARKET RETURNS.

A. These rationales demonstrate an incorrect understanding of and conflate two different things – the funded status of the pension trust and the prepaid pension asset. Changes in the market value of the pension-plan assets and changes in the benefit obligations affect the funded status of the pension plan, but they have no effect on the amount of the prepaid pension asset. As I have explained, the prepaid pension asset simply measures the difference between the cumulative pension contributions and the cumulative recognized pension expense. he fact that the plan's funded status changes periodically due to market returns or changes in benefit obligations, therefore, has no logical connection to amount of the prepaid pension asset or the issue of whether the prepaid pension asset should be included in rate base.

In any event, the value of many types of assets fluctuates based on multiple conditions such as those described above. Property valuations, such as for plants, pipes, and buildings, fluctuate based on market conditions, interest rates, investments and improvements, and the like. The amounts in rate base reflect the best information at the time rates are set in a test year, even as some depreciation continues between rate case test years. It is likewise commonly accepted to include the net book value of land (which typically does not depreciate) in rate base; even where market values change in multiple directions, this does not change the amount of the asset included in rate base. It is no different that prepaid items likewise fluctuate based on timing, interest rates, income tax rates, cost changes, and changes in applicable laws. In short, few asset or liability balances are static over time. The basis for including any of these assets in rate base is not whether their value changes, but whether they are service-producing assets derived from investments made on behalf of our customers.

Q. WHY DO YOU DISAGREE WITH THE FOURTH RATIONALE, WHICH IS THAT THE BALANCES IN THE PREPAID PENSION ASSET ARE "TEMPORARY"?

A. The vast majority of asset balances included in rate base are "temporary" in the sense that they rise and fall as new investments are made and depreciation expense is recognized. But the Company has had a prepaid pension asset for more than ten years, demonstrating that it is not a short-lived asset. Moreover, the Company accounts for the changes in the prepaid pension asset balance by using a 13-month average, as it does for other balances that vary over the year, such as materials and supplies. If the Commission is suggesting that it is temporary because at some point the asset will eventually be extinguished (as recognized pension expense depletes the prepayment balance), this is no different than assets that depreciate over time until they are fully depreciated (as depreciation expense is recognized and recovered in rates).

Q. PLEASE ADDRESS THE FIFTH RATIONALE, THAT THE PREPAID PENSION ASSET IS DIFFERENT FROM OTHER UTILITY ASSETS THAT ARE CONSTRUCTED AND DEPRECIATED AS INDICATED BY MINNESOTA LAW.

A. It is not correct that the prepaid pension asset is somehow "different than" other utility assets. The Company is required by ERISA and the Pension Protection Act to make contributions to the pension trust, just as the Company is required to make investments in physical assets such as gas pipelines and compressor stations to provide service; the dollars contributed to the pension trust are real, out-of-pocket dollars provided by investors, just like dollars spent on physical assets; and investors are entitled to a return on those dollars comparable to the return available on other types of investments.

Moreover, there is no valid basis to assert that the prepaid pension asset is different for ratemaking purposes because it is a balance sheet asset rather than an asset consisting of physical system infrastructure. First, this is true of many items. ADIT balances are also non-physical, balance sheet assets, but they are included in rate base as reductions to the balance on which the utility earns a return. Accumulated depreciation is based on the declining value of a depreciable asset but is not in itself tangible until an asset is retired or disposed. Second, these are real assets to our retired employees and our employees who plan for retirement based on their pension benefits, for whom the prepaid pension asset is funding retirement payments and ensuring continuity of retirement benefits. These assets (as well as balance sheet liabilities) are no less real simply because they are not themselves tangible.

Q. HOW DOES THIS RELATE TO THE NEXT RATIONALE, THAT IN THE ELECTRIC RATE CASE THE COMMISSION FOUND THE COMPANY DID NOT POINT TO A LAW, RULE, OR ACCOUNTING REQUIREMENT THAT REQUIRES INCLUSION OF THE ASSET IN RATE BASE?

A. In both the electric rate case and this case, I note federal laws and regulations that require the Company to make contributions to the pension fund. Given that these contributions are mandated by law and serve both customers and employees, they belong in rate base just like all other such assets. I also described throughout this testimony that including the prepaid pension asset in rate base is fundamental to ratemaking and has been required by multiple state courts.

I am not a lawyer, but as noted earlier in my Direct Testimony, other commissions have found that prepaid pension assets are entitled to a return not because of any specific state law but based on a utility's right to a reasonable opportunity to earn a reasonable return on assets contributed by the Company and its investors to provide utility service. Legal briefing may be most appropriate to address the constitutional reasons for these rights. Overall, however, the prepaid pension asset represents contributions to a pension fund that supports key retirement benefits for our employees who serve customers, and to which investors no longer have access once contributed. In short, absent a return on the investment in the pension fund, investors are required to fund an employee benefit and reduce customer pension expense without compensation for the contributions that make this possible.

Q. IS THERE ANY BASIS IN FACT OR EVIDENCE TO FIND THAT THE EXISTENCE OF THE PREPAID PENSION ASSET, OR ITS INCLUSION IN RATE BASE, WOULD BE INCONSISTENT WITH GENERALLY ACCEPTED ACCOUNTING PRINCIPLES?

A. There is none whatsoever. As I discussed earlier in my Direct Testimony, the Company's financial statements are audited by Deloitte, which would not be able to give the Company a clean audit opinion if its accounting for asset the size of our prepaid pension assets were not in accordance with GAAP. The Company also discloses its prepaid pension asset in its annual 10-K filing, as required of every company with a defined benefit plan. Moreover, multiple utilities include a prepaid pension asset on their financial statements and multiple independent auditors provide clean audit opinions for these financial statements. I note also that it is not logical that those multiple commissions and courts that have determined a prepaid pension asset must be included in rate base would all be doing so in violation of GAAP.

Q. DOES THE FACT THAT THE PREPAID PENSION ASSET EARNS AN INVESTMENT RETURN IN ANY WAY COMPENSATE INVESTORS FOR THEIR CUMULATIVE CONTRIBUTIONS TO THE PENSION FUND IN EXCESS OF CUMULATIVE EXPENSE?

A. No. While the prepaid pension asset earns an investment return, the Company's investors receive no benefit from those returns. As I have explained, every dollar of that investment return is used to reduce the pension expense charged to customers. This investment return therefore does not compensate investors in any way for the time value of their money prepaid as a cash contribution, and instead is a benefit solely to customers. As described and illustrated earlier in my testimony, the accounting standards governing pension costs require the application of an EROA to the value of the assets in the pension trust, which is then subtracted from the annual pension cost borne by customers. Investors receive no benefit whatsoever from the investment return. The mirror fact that customers benefit from the investment return on the prepaid pension assets does not justify to denying investors an investment return on the prepaid pension asset. As a result, and contrary to the Commission's supposition that the existence of such market returns support denial of a return on the prepaid pension asset, the opposite is true. Allowing customers to benefit from the market returns of the asset while denying a return to investors effectively double counts in customers' favor. Not only do they receive the benefit of the prepaid pension asset in attracting and retaining employees, but they also receive market returns from the asset without advancing any capital themselves to fund the asset.

Q. DOES THE FACT THAT THE UTILITY RECOVERS ITS ALLOWABLE PENSION EXPENSE FROM RATEPAYERS SUPPORT DENYING RECOVERY OF A RETURN ON THE PREPAID PENSION ASSET?

A. No. That rationale confuses income statement items, such as O&M expense, with balance sheet items, such as capital assets. The annual pension expense included in rates is an O&M expense, whereas the contributions to the pension trust represent a capital cost on which the utility is entitled to a return. The inclusion of pension expense in rates does not compensate investors with a return on the capital they have advanced to fund the pension trust.[27]

The Commission's rationale for denying rate base treatment of the contributions to the pension trust costs is akin to saying that utility investors do not need a return on the capital they have invested in a transmission line because the depreciation expense associated with the line, as well as the O&M costs necessary to operate and maintain the transmission line are included in rates. The utility and its investors are entitled to recover both the depreciation and O&M expenses associated with the transmission line and a return on their capital investment in the transmission line. Similarly, NSPM and its investors are entitled to recover both the annual pension expense and a return on the prepayments to the pension trust.

[27] As I have explained, a prepayment such as a prepaid pension asset reflects capital provided by the Company for the benefit of ratepayers.

Q. FINALLY, IS IT CORRECT THAT IT WOULD BE "IMPRACTICAL, IF NOT IMPOSSIBLE, TO EQUITABLY SEPARATE THE PREPAID AMOUNT ATTRIBUTABLE SOLELY TO [THE UTILITY'S] CONTRIBUTIONS FROM THAT ATTRIBUTABLE TO RATEPAYER CONTRIBUTIONS AND MARKET RETURNS"?

A. Whatever validity that reason may have with respect to other Minnesota utilities, it has none insofar as NSPM is concerned because the entire prepaid pension asset that the Company seeks to include in rate base resulted from investor contributions. As I have explained several times in my testimony, the prepaid pension asset represents the difference between the cumulative contributions by investors and the cumulative recognized pension expense. Market returns are not included in the calculation, and neither are "ratepayer contributions."[28] Perhaps for this reason, the Commission did not identify this as a barrier in its decision in the NSPM electric rate case.

Q. IN PRIOR CASES, PARTIES HAVE ARGUED THAT SOME OF THE PREPAID PENSION ASSET MUST BE ATTRIBUTABLE TO MARKET RETURNS OR CUSTOMER CONTRIBUTIONS BECAUSE THE PREPAID PENSION ASSET HAS INCREASED IN YEARS IN WHICH THERE WAS NO COMPANY CONTRIBUTION TO THE PENSION TRUST. IS THAT A VALID ARGUMENT?

A. No. That argument misunderstands the role played by negative pension expense and fails to recognize that negative pension expense does, in fact, represent an investor contribution.

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[28] I have placed quotes around the term "ratepayer contributions" because ratepayers do not make contributions to the pension trust. Only the Company makes contributions, using investors' capital. The only thing NSPM's customers pay is annual pension expense, which is an O&M expense.

Q. PLEASE EXPLAIN WHAT YOU MEAN WHEN YOU REFER TO "NEGATIVE PENSION EXPENSE."

A. As I explained earlier, annual pension cost is calculated using the following formula:

	Current service cost
+	Interest cost
-	EROA
+/-	Loss (gain) due to difference between expected and actual experience of plan assets or liabilities from prior periods
+	Amortization of unfunded prior service cost
=	Annual pension cost

If the reductions to annual pension cost (i.e., the EROA and gains due to the differences between prior-period assumptions and actual experience)[29] are larger than the other three elements of cost, the annual pension cost is negative. That reduces the cumulative recognized pension expense, and therefore necessarily increases the prepaid pension asset (which again is simply the difference between cumulative contributions to the pension plan by investors and cumulative pension expense).

Q. DOES THE FACT THAT THE NEGATIVE PENSION EXPENSE CAUSED THE PREPAID PENSION ASSET TO BE LARGER THAN IT WOULD OTHERWISE BE MEAN THAT SOMEONE OTHER THAN NSPM SHAREHOLDERS FUNDED THE INCREASE TO THE PREPAID PENSION ASSET?

A. No. NSPM's investors funded the entire prepaid pension asset. Consider an example in which the combination of the service cost, interest cost, and amortization of prior unfunded service cost totals $20 million, but the

[29] As I explained earlier, prior-period gains may result from higher-than-expected market returns, but they can also result from liability gains. Liability gains occur when the pension benefit obligation declines for reasons such an increase in the discount rate or mortality changes.

combination of the EROA and prior-period gains totals $30 million. In this example, $10 million of the gain is not needed to fund annual pension expense. In the typical scenario in which an entity utilizes a simple bank account that earns interest, the entity (a utility or otherwise) could choose to use that interest or gain on investments for operating expenses or recognize it as earnings. But because the pension fund is a trust and ERISA forbids a utility from withdrawing amounts from a pension trust other than to pay employee benefits and plan expenses, the utility in this example has no access to the earnings that its prior contributions generated, even though those earnings reduce the utility's revenue requirement. In effect, the utility is forced to forgo collection of $10 million that it would otherwise place in its bank account, and there is no material difference between writing a check for $10 million and being forced to forgo collection of $10 million that investors' contributions earned. Either way, the utility has $10 million less in its bank account. Therefore, to the extent the argument suggests that a utility is not "out of pocket" when negative pension expense reduces the cumulative recognized pension expense, that is wrong.

The suggestion that the utility is not "out of pocket" by any amount as a result of negative pension expense becomes even more obviously untenable when the development of the prepaid pension asset is viewed on a cumulative basis. Suppose that in each of the years in which there was negative pension expense, the NSPM gas department had been allowed to withdraw – and did withdraw – the negative pension expense. In those circumstances, the prepaid pension asset reflected on NSPM's books would largely disappear, but NSPM would have approximately $8.7 million more in its bank account, and customers would be earning a return on $8.7 million less of pension assets. But in reality, the $8.7 million remains in the pension trusts, and customers are earning a return on that $8.7 million. Thus, NSPM and its shareholders have indeed advanced the $8.7 million on which customers are earning a return, and they are entitled to a return on that prepayment.

Those involuntary contributions could be added to the shareholder contribution side of the equation, rather than being reflected as negative pension expense, because that is exactly what they are – involuntary shareholder contributions resulting from the federal law that prohibits withdrawals from the pension trust. Increasing the amount of contributions and leaving the amount of cumulative pension expense the same would lead to the exact same prepaid pension asset balance that NSPM has calculated in this case.

Q. PLEASE SUMMARIZE YOUR VIEWS REGARDING THE COMMISSION'S REASONS FOR DENYING UTILITIES' REQUESTS TO INCLUDE THEIR PREPAID PENSION ASSET IN RATE BASE IN RECENT CASES.

A. The Commission should approve the Company's request to include its prepaid pension asset in rate base and to earn a WACC return on it since I respectfully submit that the Commission's rationales in prior cases are either based on mistaken premises or grounded on facts that do not apply to NSPM.

F. Alternative Prepaid Pension Asset Treatment

Q. DO YOU HAVE ANY ALTERNATIVE RECOMMENDATIONS IF THE COMMISSION DENIES THE COMPANY'S REQUEST TO INCLUDE THE PREPAID PENSION ASSET IN RATE BASE?

A. Yes. As I have explained in this Direct Testimony, it would be inequitable to deny the Company a return on its prepayments to the pension trust regardless of whether that prepayment provides a financial benefit (as opposed to the provision of utility service) to customers. As further noted above, it would be doubly inequitable to deny the Company a return on that asset *and* to allow customers to earn a return on a prepayment made by the Company. Finally, it is inequitable to allow the prepaid pension asset to remain both unrecovered through pension expense and without a return on the contributions for the life of the pension plan. Only allowing a return on the prepaid pension asset avoids all three of these scenarios. But setting a shorter amortization period for the asset created by the difference between the cumulative contributions in excess of cumulative expense would at least reduce the lost opportunity cost and time value of money associated with no return on the asset and a lengthy period in which the asset would be resolved. I explain this proposal in more detail below.

Q. HAS THERE BEEN RECOGNITION IN A RECENT NSPM RATE CASE THAT IF THERE IS NO RETURN ON THE PREPAID PENSION ASSET, AT A MINIMUM SOME ALTERNATE REMEDY IS WARRANTED?

A. Yes. In addition to the past NSPM electric rate case where the Department explicitly discussed the inclusion of the prepaid pension asset in rate base and both the ALJ and Commission addressed its inclusion,[30] this alternative was

[30] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-002/GR-13-368, Findings of Fact, Conclusions, and Order at 20 (May 8, 2015)

addressed in our most recent electric rate case.[31] In our last electric rate case, the Company suggested that if the Commission departed from prior NSPM rate cases where the issue was fully addressed and a return was allowed, then the Commission should also direct the Company to recalculate qualified pension expense *without* applying the expected return to the prepayment portion of the pension trust. This would increase the amount of pension expense included in rates but would avoid the inequity of customers earning a return on the Company's cash investment without paying a corresponding return on it.

Q. DID THE ADMINISTRATIVE LAW JUDGE (ALJ) SUPPORT IMPLEMENTATION OF THIS ALTERNATIVE IN THE COMPANY'S RECENT ELECTRIC RATE CASE?

A. Yes. The ALJ recommended that the Commission require the Company to recalculate its qualified pension expense without applying the expected return to the prepayment portion of the pension trust.[32] This outcome, though not the Company's primary position as noted above, would have ensured that customers did not receive the benefit of prepaid pension fund contributions made by the Company for which the Company is not otherwise compensated. Further, in reaching this conclusion the ALJ acknowledged the existence of a prepaid pension asset contributed by the Company's investors for which investors are not being compensated.

("For rate-base purposes, the Commission will require that the pension asset reflect the cumulative difference between actual cash deposits made by the Company reduced by the recognized qualified pension cost determined under the ACM/FAS 87 methods since plan inception, not to exceed the Company's filed request."); Administrative Law Judge Findings of Fact, Conclusions of Law, and Recommendations at 37, ¶ 164 (Dec. 26, 2014) (noting the Department's recognition that the Company earns a return on its prepaid pension asset).

[31] In the Company's 2022 Gas Rate Case, the treatment of the prepaid pension asset was resolved via a settlement and unanimous settlement package, and therefore was not specifically addressed by the Commission.

[32] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-002/GR-21-630, Findings of Fact, Conclusions of Law, and Recommendations at 55 (Mar. 31, 2023) (NSPM Electric ALJ Order).

Q. DID THE COMMISSION ACCEPT THIS RECOMMENDATION?

A. No. The Commission concluded that due to the quantity and timing of the Company's data supporting this alternative request, the record was too limited to establish that the Company met its burden to support this request.[33]

Q. HOW IS THE COMPANY BALANCING THE COMMISSION'S CONCERNS WITH THE ALJ'S FINDINGS IN THIS PROCEEDING?

A. While the correct treatment of the prepaid pension asset is inclusion in rate base so that it may earn a WACC return, in this proceeding the Company is bringing an alternative proposal in its initial case filing, which will allow the entire contested case process to develop the record. Second, I am providing a simpler alternative, including supporting data and further rationale as to why this amortization alternative is reasonable. Accordingly, the Commission's concerns from the electric rate case are not applicable in this proceeding.

Q. PLEASE DESCRIBE THE COMPANY'S ALTERNATIVE PROPOSAL.

A. The Company proposes the relatively simple process of amortizing the current prepaid pension asset over an identified period of time. The goal of the alternative approach is to increase pension cost over a period of time in order to eliminate the prepaid pension asset earlier than earlier than if the current prepayment status simply lingered over the life of the plan. This increase in cost would create a regulatory liability to be included in rate base, which will offset

[33] NSPM Electric Order at 27 ("Although Xcel noted the results of its recalculations in a spreadsheet comparing the impacts of the ALJ's and parties' recommendations on the revenue requirement, the Company did not provide sufficient details to explain how it arrived at these adjusted totals or support the reasonableness of the proposed adjustments. Further, Xcel did not introduce this proposal until late in the proceedings, and parties therefore had a limited opportunity to respond. Based on the limited record on this issue, the Commission is not persuaded that Xcel met its burden to support its request.").

the prepaid pension asset balance. In this way, the prepaid pension asset will be eliminated earlier and customers will not pay a return on the asset.

Q. CAN YOU PLEASE PROVIDE MORE DETAIL REGARDING HOW THIS ALTERNATIVE WOULD WORK?

A. Yes. The Company is proposing to amortize the asset and recover the resulting increase in pension cost based on the December 31, 2022 prepaid pension asset balance of $14,510,284 for the Minnesota Gas jurisdiction. The math of this approach simply involves dividing the balance of the Minnesota gas jurisdictional balance of the prepaid pension asset as of December 31, 2022 by the selected number of years. Table 16 below shows the results of various amortization periods for this proposal to enable comparison of outcomes, with the ultimate goal of completely offsetting the current prepaid pension asset balance so the net impact to rate base is zero.

Table 16
Amortization of Prepaid Pension Asset Balance

MN Gas Balance 12/31/2022	**$**	**14,510,284**
Annual Amortization (4 years)	$	3,627,571
Annual Amortization (6 years)	$	2,418,381
Annual Amortization (8 years)	$	1,813,785
Annual Amortization (10 years)	$	1,451,028
Annual Amortization (12 years)	$	1,209,190

Eventually the accounting formulas will reduce the prepaid pension asset as over the life of the plan contributions and expense will equal. When the asset balance naturally unwinds, the regulatory liability previously established via this alternative will be returned to customers.

Q. IS THERE PRECEDENT FOR THIS APPROACH IN OTHER XCEL ENERGY JURISDICTIONS?

A. Yes. Multiple stakeholders and the Colorado Public Utilities Commission (CPUC) have recognized for years, including during timeframes when certain intervenors objected to the Company earning a return on the prepaid pension asset, that cumulative contributions to the employee pension plans in excess of cumulative pension expense recovered from customers create an asset. Over the course of multiple rate cases between at least 2014 and 2020, the Company and stakeholders (including Trial Staff of the CPUC) argued about the appropriate return to apply to the prepaid pension asset if any, and in 2014 the parties settled the issue by agreeing to amortize the prepaid pension asset to eliminate it earlier. The parties also agreed to include the unamortized historical portion in rate base at the Company's cost of debt. In the Company's subsequent, fully litigated rate case, and in each rate case since 2014 (whether electric or gas, and whether the issue or the case was litigated or settled) a similar approach has been utilized for legacy (pre-existing to that rate case) prepaid pension assets.[34]

As I previously noted, in 2020 the CPUC's decision to deny a return on the prepaid pension asset was reversed on appeal,[35] and since that time the Company has earned a WACC return on its prepaid pension asset in every Xcel Energy jurisdiction except Minnesota. The amortization of the legacy prepaid

[34] *In the Matter of Advice Letter No. 1672-Electric Filed by Public Service Company of Colorado to Revise its Colorado P.U.C. No. 7-Electric Tariff to Implement a General Rate Schedule Adjustment and Other Changes Effective July 18, 2014*, Decision No. C15-0292 at ¶ 48 (Mailed March 31, 2015); *In the Matter of the Advice Letter No. 876-Gas Filed by Public Service Company of Colorado to Increase Rates for All Natural Gas Sales and Transportation Services to Become Effective April 3, 2015*, Decision No. R15-1204 at ¶ 22 (Mailed November 16, 2015), Decision No. C16-0123 at ¶ 64 (Mailed February 16, 2016).

[35] *Public Service Company of Colorado v. The Public Utilities Commission of the State of Colorado*, Case No. 19CV31427, Order at 18 (Denver County District Court, Mar. 12, 2020). The Colorado commission did not appeal the district court decision to the Colorado Supreme Court.

pension asset has also continued, as this approach has the benefit not only extinguishing the asset more quickly, but also reducing the total return necessary over time to compensate NSPM for its cumulative contributions to the pension fund in excess of cumulative pension expense recovered through rates.

Q. HOW DOES THE COMPANY'S ALTERNATIVE PROPOSAL IN THIS CASE COMPARE TO THE APPROACH UTILIZED FOR XCEL ENERGY IN COLORADO?

A. It is the same amortization approach, albeit without a return on the portion of the asset in rate base. Further, because the Company is currently earning no return on the asset, the Company proposes to amortize the asset over six years. This approach reasonably balances the impact to customer rates while reducing the financial impact on the Company of making such material contributions without earning a return on them. Ultimately, the length of the amortization period for purposes of setting rates would be a regulatory determination by the Commission, no different from other situations where cost recovery is extended over a longer period than the period in which the associated costs were incurred.

Q. IS THIS ALTERNATIVE PREFERABLE TO THE COMPANY'S PRIMARY PROPOSAL?

A. No. To be clear, denying a return on the prepaid pension asset is not NSPM's primary recommendation, and the Company remains concerned that such a denial does not consider the cost to NSPM of funding the service-producing prepaid pension asset. Further, given that customers already earn a return on the asset through the reduction to qualified pension expense, customers benefit from this asset and are not harmed by providing a return on the contributions that fund it. Therefore, NSPM's primary recommendation is that the Company be allowed to earn a return on the prepaid pension asset. If, however, the Commission does not provide for compensation for the Company's investment in the prepaid pension asset that is benefiting customers, then the asset should be amortized over the shortest possible period to reduce the amount of time customers and employees have the use of these funds without providing a return on the investment. While this does not solve for the lost time value of money while the asset is being amortized, it does reduce the impact of the denial of a return on the asset.

VIII. ACTIVE HEALTH AND WELFARE COSTS

Q. WHAT IS THE ACTIVE HEALTH AND WELFARE COST FOR 2024?

A. The 2024 health and welfare expense amount is approximately $5.2 million.

Q. WHAT TYPES OF BENEFIT COSTS ARE INCLUDED IN ACTIVE HEALTH AND WELFARE?

A. Active health and welfare costs can be broken down into three categories. The first and largest category is for active healthcare costs; the second category is for miscellaneous benefit programs and costs; and the third category contains life, LTD, and business travel insurance premiums.

Q. SINCE ACTIVE HEALTH AND WELFARE CONSISTS OF THREE CATEGORIES OF COSTS, CAN YOU PROVIDE A FURTHER BREAKDOWN OF COSTS IN THE TEST YEAR?

A. Yes. Exhibit___(RRS-1), Schedule 12, 2024 Test Year Health and Welfare O&M shows the components that are included in each category and the amount for each component in the test year. The active healthcare category makes up nearly 90 percent of the total health and welfare costs.

Q. WHAT TYPES OF COSTS ARE INCLUDED IN ACTIVE HEALTHCARE?

A. Active healthcare costs are all costs associated with providing healthcare coverage to our employees. As explained in more detail by Company witness Deselich, active healthcare benefits include medical, pharmacy, dental and vision claims, administrative fees, employee withholdings, pharmacy rebates, Health Savings Account (HSA) contributions, transitional reinsurance fees, trustee fees, interest income and opt-out finding.

Q. DID THE COMPANY MAKE ANY ADJUSTMENTS TO THE PER BOOK AMOUNTS FOR ACTIVE HEALTHCARE CLAIMS?

A. Yes. Table 17 below shows both the per book and actual incurred amounts of active health and welfare claims for the five years prior to the test year and for the 2024 test year.

Table 17
Active Health Care
Per Book and Actual Incurred Claims
NSPM Gas O&M State of MN ($)

Year	Per Book Amount	IBNR Adjustment	Actual Incurred Claims
2020	2,897,942	(579,348)	2,318,593
2021	3,463,469	(125,586)	3,337,883
2022	3,860,937	(86,782)	3,774,155
2023 Forecast	4,326,116	(37,557)	4,288,559
2024 Test Year	n/a	n/a	4,677,724

Q. WHY WAS IT NECESSARY TO MAKE AN ADJUSTMENT TO THE PER BOOK CLAIMS AMOUNT?

A. This adjustment is necessary to reflect actual costs incurred in each year. The per book amounts for active healthcare include estimates because there is generally an average lag of approximately 30 days between when healthcare is provided and when the Company receives a bill for that care. Therefore, the actual amount of active healthcare expense was not available at the time the Company recorded its per book amount at the end of each month. Because the Company needs to close its books at the end of each reporting period before it receives all of those healthcare claims, it takes the actual amounts recorded through a certain point in the year and estimates the additional amount that will be incurred but not reported (IBNR) by the end of the reporting period. This accrual estimate is called the IBNR reserve. During the following period, the Company receives the actual amounts attributable to care provided in the last part of the prior period, and at that time it trues up the IBNR estimate to the actual incurred amount. Therefore, the per book amounts need to be adjusted so that they reflect the actual incurred claim amounts during that period. After the adjustment, the periods include only the actual amounts incurred for the twelve months.

Q. HOW WERE THE 2024 ACTIVE HEALTHCARE COSTS DETERMINED?

A. The Company's actuary, Willis Towers Watson, calculated the 2024 test year medical and pharmacy amounts by using the actual experience from the following periods and weighting them.

An 80 percent weighting was applied to:

- Medical claims incurred January 1, 2021 through December 31, 2021, paid through February 29, 2023.
- Pharmacy claims incurred January 1, 2021 through December 31, 2021, paid through February 29, 2023.

A 20 percent weighting was applied to:

- Medical claims incurred January 1, 2022 through December 31, 2022, paid through February 29, 2023.
- Pharmacy claims incurred January 1, 2022 through December 31, 2022, paid through February 29, 2023.

Willis Towers Watson then adjusted for changes in plan design, regulations, administrative fees, etc., and it trended the data forward to 2024 using inflation factors. These costs are calculated at a plan level, meaning all companies with employees in that plan are calculated together. Willis Towers Watson then adjusts this estimate to account for actual claims experience by company.

Q. WHAT PERCENTAGE DOES TOTAL HEALTH AND WELFARE COSTS INCREASE IN 2024 BASED ON THE METHODOLOGY DESCRIBED ABOVE?

A. As shown in Table 18 below, the amounts reflect an increase of 9.07 percent, which is right in line with the expected healthcare trend.

Table 18
Active Health Care Expense
NSPM Gas O&M State of MN

	2023 Forecast	2024 Test Year
Active Healthcare ($)	4,288,559	4,677,724
Year-Over-Year Change		9.07%

Q. IS THE COMPANY'S HEALTHCARE COST INCREASE REASONABLE?

A. Yes. Exhibit___(RRS-1), Schedule 13, Medical and Pharmacy Cost Trend Assumptions, shows Willis Towers Watson's overall expectation of healthcare cost increases based on survey averages, carrier information, and an analysis of the broad healthcare market. This study is from June 2023 and is focused on 2024 expected cost increases. The information is intended to support the trend assumptions used in Xcel Energy's 2024 active healthcare budgeting done by Willis Towers Watson. Overall, the Willis Towers Watson survey data indicates each pricing group has a different split of the total cost between medical and pharmacy cost, but they expect the total trend to be between 6.50 percent and 6.80 percent as documented in the trend surveys. PricewaterhouseCoopers (PwC) estimates that medical and pharmacy costs will rise 6.00 percent in 2021. This information, which was gathered by PwC's Health Research Institute, was based on PwC's own internal research and input from health plan actuaries, industry leaders, analyst reports, and employer surveys. Finally, the Aon Carrier Trend Report expects 2024 medical costs to increase by 6.50 percent in the US and 9.20 percent globally. In addition to these anticipated medical cost increases the Company anticipates that pharmacy costs will increase by 14.0 percent.

Q. DO YOU BELIEVE THE COMPANY'S ESTIMATE OF HEALTHCARE COSTS IS REPRESENTATIVE OF COSTS THE COMPANY EXPECTS TO INCUR IN FUTURE YEARS?

A. Yes. As shown in Table 18 above, the Company's active healthcare costs are currently forecasted to grow approximately 9.07 percent per year for 2024. The 9.07 percent growth includes both medical and pharmacy cost increases. This growth rate is typical as compared to other organizations, as demonstrated by the attachment referred to above, and is actually lower than the Company's rate of cost increases over the last several years. The Company has implemented several plan design changes to help control the pace of growth, as discussed by Company witness Deselich. However, active healthcare costs have continued to increase, and the Company's forecast through 2024 are reasonable.

Q. WHY IS IT REASONABLE FOR CUSTOMERS TO PAY ACTIVE HEALTH AND WELFARE COSTS INCURRED BY THE COMPANY?

A. It is appropriate that customers pay for these benefits because they reflect a reasonable and necessary level of expense. Employees expect their employer to provide a reasonable level of health and welfare benefits, and any employer that does not do so is at a significant disadvantage in the labor market. Thus, our compensation plans and benefits are required to attract, retain, and motivate employees needed to perform the work necessary to provide quality services for NSPM customers.

Q. WHAT TYPES OF COSTS ARE INCLUDED IN MISC BEN PROGRAMS, LIFE, LTD?

A. As mentioned above, active health and welfare costs can be broken down into three categories. The first and largest category is for active healthcare costs; the second category is for miscellaneous benefit programs and costs; and the third category contains life, LTD, and business travel insurance premiums. Schedule

12 shows a breakout of all the components that are included in each category and the amount for each component in the test year. The majority of the costs included within the second and third categories mentioned above are not material on an individual basis. However, third-party LTD insurance premiums make up nearly half of the costs included in the two categories for the Test Year. The Company has included $228,019 in third-party insured LTD benefit in the Test Year.

IX. WORKERS' COMPENSATION FERC 925 COSTS

Q. WHAT TYPES OF COSTS ARE INCLUDED IN FERC ACCOUNT 925, INJURIES AND DAMAGES?

A. FERC Account 925 is composed of workers' compensation coverage and other liability insurance costs. The workers' compensation benefit covers work-related injury costs for medical claims, permanent or partial disability, lost time, rehabilitation costs, prescription drugs, etc. The other liability insurance includes coverage for general liability, excess liability, fiduciary insurance, and directors' and officers' insurance. Because my area of responsibility is in benefits accounting, my testimony is limited to the workers' compensation costs.

Q. PLEASE EXPLAIN HOW WORKERS' COMPENSATION COSTS ARE DETERMINED.

A. Similar to LTD costs, the accounting treatment for workers' compensation differs for the self-insured and fully-insured portions of the plan. The workers' compensation benefit is self-insured for any active bargaining or non-bargaining employee who was injured before August 1, 2001, and it is fully insured for any employee who was injured on or after that date. The Company is required to accrue for self-insured workers' compensation costs under FAS 112. The fully-insured portion is the cost of the insurance premiums that the Company must pay each year.

Q. WHAT HAS BEEN THE TREND FOR THE WORKERS' COMPENSATION COSTS OVER THE LAST SEVERAL YEARS AND FOR THE TEST YEAR?

A. Table 19 below compares the workers' compensation benefit costs from 2020 through 2024.

Table 19
Workers' Compensation Expense
NSPM Gas O&M State of MN ($)

Year	FAS 112	Insurance Premiums & Other	Total Workers' Compensation
2020	42,932	225,468	268,400
2021	22,361	156,591	178,952
2022	52,762	263,421	316,183
2023 Forecast	(56,742)	153,247	96,505
2024 Test Year	18,750	314,184	332,934

Q. HOW DID YOU CALCULATE THE WORKERS' COMPENSATION AMOUNTS FOR 2024?

A. The FAS 112 amounts are based on the 2024 projected cost amounts from the Willis Towers Watson actuarial calculation provided in June 2023. The insurance premium amounts were based on the actual premiums paid through October 2022 and held relatively flat through 2023.

Q. WHAT CAUSES THE FLUCTUATIONS IN THESE COSTS FROM YEAR TO YEAR?

A. The FAS 112 workers compensation self-insured costs fluctuate from year to year because of changes to the discount rate or demographic adjustments, similar to FAS 112 LTD costs, which were discussed above. The workers compensation premium portion remained relatively stable from 2020 to 2024, with the fluctuations in costs being driven primarily by captive distributions (refunds) from the captive insurance.

Q. HAS THE COMPANY PROVIDED THE ACTUARIAL STUDY AND DERIVATION OF THE JURISDICTIONAL AMOUNT?

A. Yes. The Company has included Schedule 7, which is an actuarial study that supports the FAS 112 workers compensation costs in 2023-2024. Schedule 8 shows the conversion of the 2024 total cost amounts to the NSPM gas O&M, State of Minnesota amount.

Q. IS THE COMPANY SEEKING TO RECOVER THE FORECASTED WORKERS' COMPENSATION EXPENSE AS SHOWN IN TABLE 19 AS PART OF ITS TEST YEAR?

A. Yes. Company witness Halama has incorporated the budgeted amounts into the 2024 test year revenue requirements. These costs are calculated in accordance with accounting rules and standards and are based on actuarial assumptions specific to the Company.

X. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY AND RECOMMENDATIONS.

A. The assumptions that the Company has used to determine the test year pension expense are reasonable, as shown by comparison with other utilities' pension assumptions. In addition, we are proposing to use a five-year average discount rate – as the Commission approved in a prior Company case – to reduce the potential number of disputed issues in this current case. Our annual qualified pension expense decreased from 2022 actuals compared to the 2024 test year, in part due to the benefit plan design changes that have reduced employee benefit levels.

The Company should be allowed to recover the costs of its FAS 106 post-retirement medical benefit and its FAS 112 benefit. Those are reasonable costs that are part of the total compensation package the Company needs to attract and retain good employees.

The Company should also be allowed to include its prepaid pension asset in rate base and to earn a return on that asset at the Company's WACC. The gains from that asset help reduce pension expense in the test year, but shareholders have no access to those gains. The Company requests that the prepaid pension asset be included in rate base and that it earn a return, similar to other prepayments. If the Commission should deny that request, the Company recommends amortizing the prepaid pension asset over six years to reduce the time period over which the asset exists without earning a return.

Regarding healthcare costs, we have implemented measures to help control the pace of growth in our healthcare costs, and the result is reflected in a lower inflation factor during the test year period than that recommended by our actuaries and PwC.

Finally, our workers' compensation costs are necessary, and the forecasted amounts presented in my testimony should be approved for recovery in rates.

In summary, and as discussed in more detail by Company witness Deselich, the non-cash employee benefits discussed in my testimony are part of the Company's overall compensation and benefits package and are necessary to attract and retain the employees required to provide high-quality service to our customers. The forecasted amounts of pension and benefits costs I present are reasonable and accurately reflect our expected pensions and benefits expense in the test year period. As such, I recommend that the Commission approve these levels of expense to be included in rates.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Statement of Qualifications

Richard R. Schrubbe

Current Responsibilities

As Area Vice President, Financial Planning and Analysis, I am responsible for overseeing the business area leaders of Energy Supply, Transmission, Distribution, Gas Engineering & Operations and Corporate Services with respect to budget planning, reporting, and analysis. I oversee the accounting for all employee benefits programs, playing a liaison role with the Human Resources department, external actuaries, and senior management with benefit fiduciary roles. I am also responsible for coordinating the benefits operations and maintenance ("O&M") and capital budgeting and forecasting processes, as well as the monthly analysis of actual results against these budgets and forecasts.

Experience

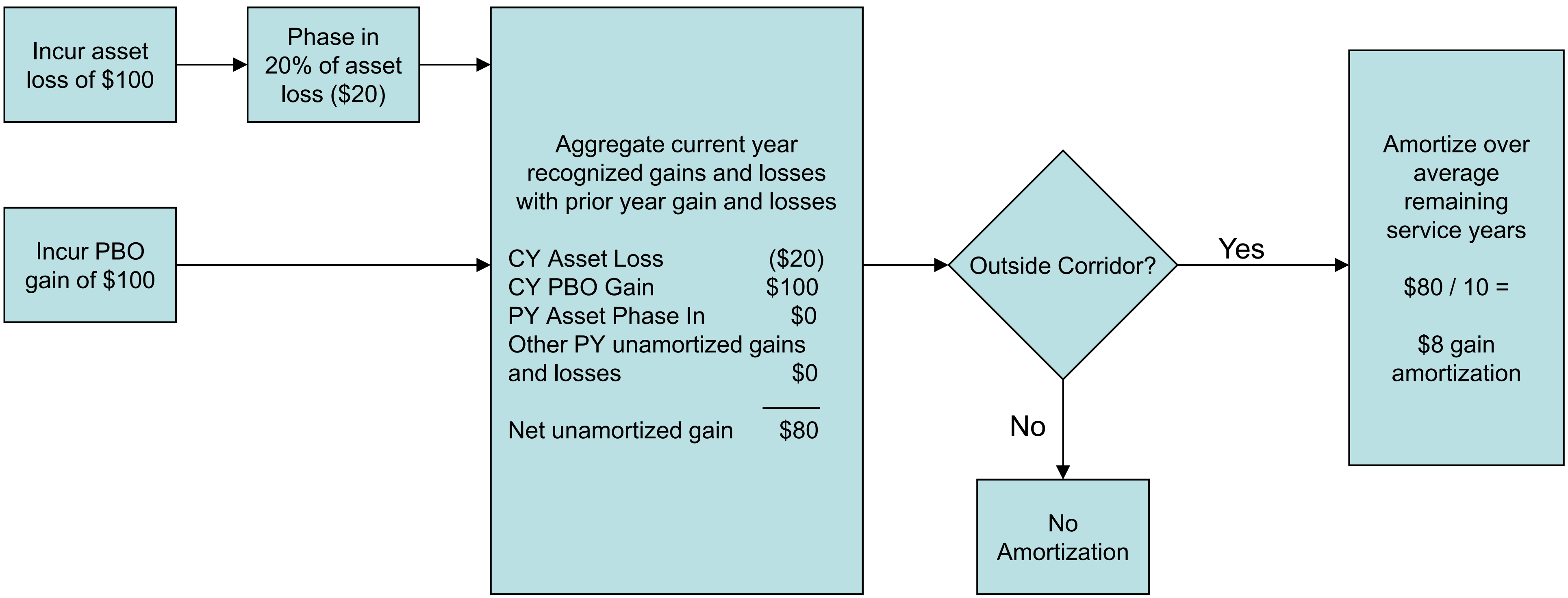
2007 – Present Xcel Energy Inc.	Area Vice President, Financial Planning & Analysis

Education

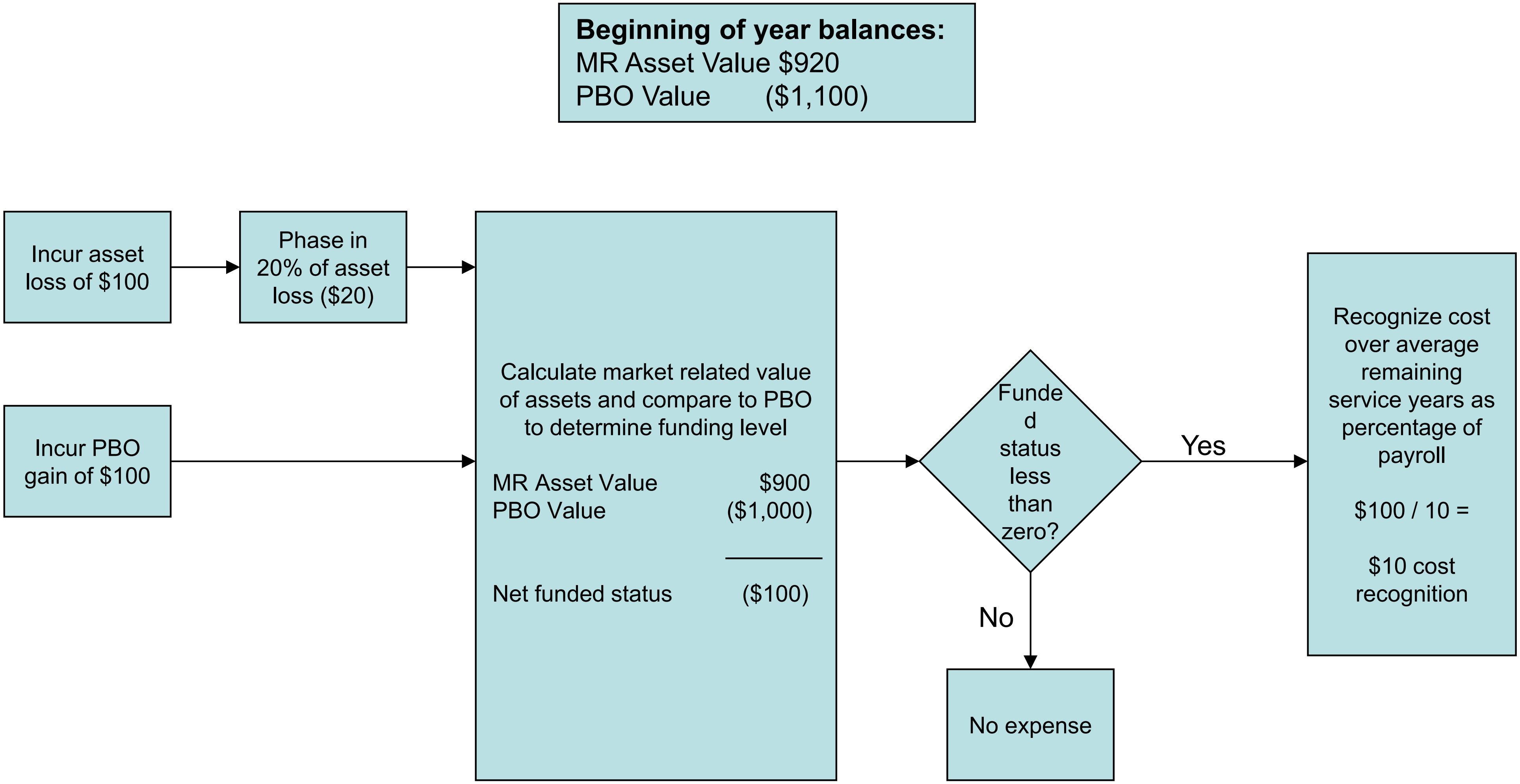
1996 Bachelor of Science Business Admin, Finance	Marquette University

SFAS 87 Amortization

Assumes no prior year gain or loss balance



ACM Amortization



Description of Components and Calculations
Under Aggregate Cost Method (ACM) and SFAS 87 (ASC 715)

A. Aggregate Cost Method

1. Components of the Aggregate Cost Method

The costs are determined using the following components:

a) the value of pension benefits expected to be paid in all future years (the "Present Value Of Future Benefits");
b) the value of plan assets (the "Valuation Assets");
c) the value of expected future compensation to be paid to active employees (the "Present Value Of Future Compensation");
d) the discount rate to be applied to all compensation expected to be paid to current employees (the "Aggregate Cost Discount Rate"); and
e) the rate of return equal to the expected long-term rate of return on plan assets (the "Aggregate Cost Rate of Return").

Under the Aggregate Cost Method, the pension cost represents an amount that would need to be paid into the pension fund each year to pay all future benefits under the plan. The difference between the Present Value of Future Benefits and the Valuation Assets determines the unfunded benefits as of the valuation date. The unfunded benefits are divided by the Present Value of Future Compensation to determine the annual percentage of compensation that would need to be paid into the pension fund each year to fully fund all future benefits. The pension cost is equal to this percentage multiplied by the compensation expected to be paid to active employees in the upcoming year.

2. Present Value of Future Benefits

The Present Value of Future Benefits is determined by projecting into the future all benefits expected to be paid to plan participants. This projection requires future assumptions regarding mortality, when participants will leave the company and future salary increases. The benefits expected to be paid are discounted back to the valuation date by the Aggregate Cost Discount Rate.

3. Valuation Assets

Valuation Assets are based on adjusted market value of assets, which is a calculated value that recognizes changes in fair value in a systematic and rational manner over not more than five years. The adjusted market value is subject to restriction that it be not less than 80 percent and not more than 120 percent of the market value of assets. Contributions that have been included in prior costs but have not been contributed to the pension fund are added to the Valuation Assets. Contributions that have been contributed to the pension fund but have not been included in prior costs are subtracted from the Valuation Assets.

4. Present Value Of Future Compensation

The Present Value of Future Compensation is determined by projecting into the future all compensation expected to be paid to current employees. This projection requires future assumptions regarding mortality, termination and retirement rates and future salary increases. The compensation expected to be paid is then discounted back to the valuation date using the Aggregate Cost Discount Rate.

5. Aggregate Rate of Return

The Company develops the Aggregate Cost Rate of Return based on expectations provided by Pacific Global, the pension fund manager. These expectations are based on the composition of plan assets.

6. Aggregate Cost Discount Rate

The Aggregate Cost Discount Rate is equal to the expected long-term rate of return on plan assets.

7. Validation of Reasonableness of the Assumptions

The Company's independent actuary, Towers Watson, calculates the expense and obligations under the Aggregate Cost Method based on actual experience and company demographics, along with assumptions for the Aggregate Cost Discount Rate and Aggregate Cost Rate of Return. Towers Watson also provides results of surveys of discount rates and rates of return for review. In addition, all material assumptions are reviewed by Deloitte and Touche, the Company's external auditor, for reasonableness.

B. FAS 87 (ASC 715)

1. Components of the ASC 715 Method

Under FAS 87, pension cost is made up of several components including:

a) the value of pension benefits that employees will earn during the current year ("Service Cost");
b) increases in the present value of the pension benefits that plan participants have earned in previous years ("Interest Cost");
c) investment earnings on the pension plan assets that are expected to be earned during the year ("Expected Return On Assets");
d) recognition of costs (or income) from experience that differs from the assumptions (*e.g.*, investment earnings different than assumed) ("Amortization Of Unrecognized Gains And Losses"); and
e) recognition of the cost of benefit changes the plan sponsor provides for service the employees have already performed ("Amortization Of Unrecognized Prior Service Cost").

2. Service Cost

The Service Cost is the actuarial present value of benefits attributed by the pension benefit formula to current employees' service during that period. Actuarial assumptions are used to reflect the time-value of money (the discount rate) and the probability of payment (assumptions as to mortality, turnover, early retirement, and others).

3. Interest Cost

The Interest Cost recognized in a fiscal year is determined as the increase in the projected benefit obligation due to the passage of time. Measuring the projected benefit obligation as a present value requires accrual of an Interest Cost at a rate equal to the assumed discount rate. The Interest Cost identifies the time value of money by recognizing that anticipated pension benefit payments are one year closer to being paid from the pension plan.

4. Expected Return On Assets

The Expected Return On Assets is determined based on the expected long-term rate of return on plan assets and the market-related value of plan assets. The marketrelated value of plan assets can be either fair market value or a calculated value that recognizes changes in fair value in a systematic and rational manner over not more than five years.

5. Amortization Of Unrecognized Gains And Losses

Gains and losses are changes in the amount of either the projected benefit obligation or plan assets resulting from experience different from that assumed or from changes in assumptions. ASC 715 does not distinguish between sources of gains and losses. Asset gains and losses are the differences between the actual return on assets during a period and the expected return on assets for that period. Liability gains and losses are the differences between the actual liability at the end of a measurement period and the expected liability at the end of a measurement period. FAS 87 does not require recognition of gains and losses as a component of net pension cost in the period in which they arise.

Amortization Of Unrecognized Net Gains Or Losses must be included as a

component of net periodic pension cost for a year if, as of the beginning of the year, the unrecognized net gain or loss exceeds a "corridor," which is 10 percent of the greater of the projected benefit obligation or the market-related value of plan assets. If Amortization Of Unrecognized Net Gains Or Losses is required, the amortization amount is equal to the amount of the Unrecognized Gain Or Loss in excess of the corridor divided by the average remaining future service of the active participants in the plan.

6. Amortization Of Unrecognized Prior Service Cost

Plan amendments can change benefits based on services rendered in prior periods. FAS 87 does not generally require the cost of providing such retroactive benefits (prior service cost) to be included in net periodic pension cost entirely in the year of the amendment but provides for recognition over the future years. Unrecognized prior service cost is amortized in the same manner as unrecognized gains and losses with the exception of the 10 percent corridor.

7. FAS 87 Rate of Return

The Company develops the FAS 87 Rate of Return based on expectations provided by JP Morgan, the pension fund manager. These expectations are based on the composition of plan assets.

8. FAS 87 Discount Rate

The FAS 87 Discount Rate is based on a bond matching approach which is
recalculated on an annual basis to most accurately value the liability at a point in time.

9. Validation of Reasonableness Of The Assumptions Used

The Company's independent actuary, Towers Watson, calculates the expense and obligations under ASC 715 based on actual experience and company demographics, along with assumptions for the FAS 87 Discount Rate and FAS 87 Rate of Return. Towers Watson also provides results of surveys of discount rates and rates of return for review. All material assumptions are also reviewed for reasonableness by Deloitte and Touche, the Company's external auditor.

C. Accounting Standards and Example of the Phase In of Pension Asset Losses Over Five Years

The company "phases in" losses over 5 years and then amortizes these losses over the average years to retirement. SFAS 87 allows the company to use a calculation referred to as the "market-related value of plan assets" to recognize changes in asset values over a period not to exceed 5 years. For example assume the company had plan assets with a fair value of $3,000,000 and those assets then lost $1,000,000 in value. The accounting standard allows the company to recognize the change in the value of these assets through the market related value of these assets. As a result, the company would recognize only $200,000 ($1,000,000 x 1/5) of market loss per year for a period of five years. In the year of the losses, the market related value of assets would be $2,800,000 ($3,000,000 – $200,000) The $200,000 represents 1/5 of the actual losses. This loss would then be amortized over the average remaining years of service (10 years). As a result, in year 1 loss amortization would be $200,000 divided by 10, or $20,000. The table below shows how losses would be phased in and then amortized.

Event	Fair Value of Assets	Market Related Value of Assets	Total Recognized	Year 1 Amort	Year 2 Amort	Year 3 Amort	Year 4 Amort	Year 5 Amort	Year 6 Amort
Beg Year 0	3,000,000	3,000,000	0						
Yr 0 Asset loss	2,000,000	2,800,000	200,000	20,000	20,000	20,000	20,000	20,000	20,000
	2,000,000	2,600,000-	400,000		20,000	20,000	20,000	20,000	20,000
	2,000,000	2,400,000	600,000			20,000	20,000	20,000	20,000
	2,000,000	2,200,000	800,000				20,000	20,000	20,000
	2,000,000	2,000,000	1,000,000					20,000	20,000
	Total Amortization			20,000	40,000	60,000	80,000	100,000	100,000

The accounting standard that allows the Company to smooth in the pension asset gains or losses over a five-year period is the Statement of Financial Accounting Standard ("SFAS") 87, Employers' Accounting for Pensions. The specific guidance can be found on page 14, paragraph 30 and 31, which I have copied below for your reference. The relevant reference is bolded and underlined.

> 30. The expected return on plan assets shall be determined based on the expected long-term rate of return on plan assets and the market-related value of plan assets. **The market-related value of plan assets shall be either fair value or a calculated value that recognizes changes in fair value in a systematic and rational manner over not more than five years.** Different ways of calculating market-related value may be used for different classes of assets (for example, an employer might use fair value for bonds and a five-year-moving-average value for equities), but the manner of determining market-related value shall be applied consistently from year to year for each asset class.
>
> 31. Asset gains and losses are differences between the actual return on assets during a period and the expected return on assets for that period. Asset gains and losses include both (a) changes

reflected in the market-related value of assets and (b) changes not yet reflected in the market-related value (that is, the difference between the fair value of assets and the market-related value). Asset gains and losses not yet reflected in market-related value are not required to be amortized under paragraphs 32 and 33.

Schedule 4
XEPP Fund Analysis
(Amounts in Thousands)

Year	Beginning of Year Market Value	Contributions	Earnings on Fund Investments	Pension Payments	Acquisitions/Transfers	Settlements	End of Year Market Value	Return on Assets
1950	-	1,023	(17)	(16)	-		989	-3.46%
1951	989	2,185	13	(145)	-		3,043	0.63%
1952	3,043	2,184	316	(200)	-		5,342	7.83%
1953	5,342	2,394	8	(263)	-		7,481	0.13%
1954	7,481	2,626	1,266	(346)	-		11,026	14.67%
1955	11,026	2,851	1,544	(444)	-		14,977	12.61%
1956	14,977	2,841	879	(534)	-		18,163	5.45%
1957	18,163	3,511	97	(772)	-		21,000	0.50%
1958	21,000	3,715	1,528	(958)	-		25,284	6.83%
1959	25,284	4,045	3,929	(1,135)	-		32,123	14.69%
1960	32,123	4,267	2,571	(1,359)	-		37,602	7.65%
1961	37,602	4,716	4,121	(1,557)	-		44,882	10.51%
1962	44,882	5,047	(4,158)	(1,785)	-		43,987	-8.94%
1963	43,987	5,219	7,373	(2,094)	-		54,485	16.18%
1964	54,485	5,469	6,666	(2,442)	-		64,177	11.90%
1965	64,177	5,749	3,023	(2,763)	-		70,186	4.60%
1966	70,186	5,690	3,252	(3,269)	-		75,860	4.56%
1967	75,860	5,650	5,727	(3,631)	-		83,606	7.45%
1968	83,606	5,647	7,919	(4,017)	-		93,154	9.38%
1969	93,154	5,785	(2,745)	(4,590)	-		91,604	-2.93%
1970	91,604	5,857	(11,557)	(5,267)	-		80,637	-12.57%
1971	80,637	6,203	18,077	(5,743)	-		99,174	22.34%
1972	99,174	6,939	13,010	(5,967)	-		113,157	13.05%
1973	113,157	7,533	(3,960)	(6,767)	-		109,963	-3.49%
1974	109,963	7,138	(10,668)	(7,590)	-		98,842	-9.72%
1975	98,842	8,967	16,770	(8,079)	-		116,500	16.88%
1976	116,500	10,790	12,240	(8,823)	-		130,707	10.40%
1977	130,707	13,128	5,803	(10,136)	-		139,503	4.38%
1978	139,503	16,308	7,166	(10,037)	-		152,940	5.02%
1979	152,940	18,071	26,014	(10,609)	-		186,416	16.59%
1980	186,416	20,523	41,250	(11,590)	-		236,599	21.59%
1981	236,599	23,131	(15,502)	(12,705)	-		231,523	-6.41%
1982	231,523	27,270	59,048	(14,242)	-		303,599	24.80%
1983	303,599	27,740	66,064	(5,743)	-		391,659	21.37%
1984	391,659	28,520	24,017	(19,084)	-		425,113	6.06%
1985	425,113	27,633	115,267	(22,959)	-		545,054	26.97%
1986	545,054	26,360	89,279	(24,836)	-		635,857	16.36%
1987	635,857	23,621	48,170	(27,898)	-		679,750	7.60%
1988	679,750	22,583	83,165	(40,645)	-		744,853	12.40%
1989	744,853	22,154	192,138	(44,303)	-		914,842	26.18%
1990	914,842	20,224	(11,273)	(56,827)	-		866,966	-1.26%
1991	866,966	22,248	248,374	(57,966)	-		1,079,623	29.25%
1992	1,079,623	21,516	121,945	(66,077)	-		1,157,007	11.53%
1993	1,157,007	-	153,083	(65,818)	-		1,244,272	13.62%
1994	1,244,272	-	15,665	(94,120)	-		1,165,817	1.31%
1995	1,165,817	-	345,631	(54,811)	-		1,456,637	30.36%
1996	1,456,637	-	274,978	(96,827)	-		1,634,787	19.53%
1997	1,634,787	-	428,004	(84,201)	-		1,978,590	26.87%
1998	1,978,590	-	330,836	(87,526)	-		2,221,900	17.10%
1999	2,221,900	-	305,501	(108,764)	-		2,418,637	13.98%
2000	2,418,637	-	89,651	(135,462)	38,412		2,411,238	6.90%
2001	2,411,238	-	(204,933)	(115,459)	-		2,090,846	-8.31%
2002	2,090,846	912	(318,389)	(155,606)	157,157	(994)	1,773,926	-10.90%
2003	1,773,926	1,712	372,354	(169,645)	-	(9,546)	1,968,801	22.61%
2004	1,968,801	-	179,697	(161,054)	-	(27,627)	1,959,817	9.34%
2005	1,959,817	-	160,630	(168,429)	-		1,952,018	8.73%
2006	1,952,018	-	189,246	(175,904)	-		1,965,360	10.24%
2007	1,965,360	-	121,057	(153,335)	-		1,933,082	6.60%
2008	1,933,082	-	(479,747)	(164,179)	-		1,289,156	-25.26%
2009	1,289,156	-	132,142	(113,427)	-		1,307,871	11.94%
2010	1,307,871	34,132	145,913	(147,452)	-		1,340,464	12.77%
2011	1,340,464	70,635	78,696	(153,274)	-		1,336,521	6.28%
2012	1,336,521	142,581	164,743	(146,248)	-		1,497,597	11.64%
2013	1,497,597	125,175	105,333	(178,392)	(14,931)		1,534,782	7.08%
2014	1,534,782	90,029	108,591	(184,049)	12,950		1,562,303	7.22%
2015	1,562,303	58,057	(17,038)	(154,384)	5,874		1,454,812	-1.25%
2016	1,454,812	90,050	92,086	(190,440)	12,415		1,458,923	6.66%
2017	1,458,923	120,308	216,751	(234,403)	1,378		1,562,957	15.29%
2018	1,562,957	120,000	(69,515)	(237,016)	(2,444)		1,373,982	-4.51%
2019	1,373,982	90,188	284,993	(162,284)	3,928		1,590,807	20.91%
2020	1,590,807	85,000	267,124	(174,129)	8,721		1,777,523	17.49%
2021	1,777,523	70,310	153,974	(253,413)	1,244		1,749,638	9.32%
2022	1,749,638	10,000	(300,218)	(233,189)	1,626		1,227,857	-17.86%
Totals		1,604,158	4,504,990	(5,069,454)	226,330	(38,167)	60,480,176	

EEI Pension and OPEB Survey 2022-23

Company	Expected Discount Rate		Yield Curve / Model (Firm)	Yield Curve / Model (Specific)	Long-Run Expected Return		Expected Return CY (2022)		Expected Return CY+1 (2023)	
	Pension	OPEB			Pension	OPEB	Pension	OPEB	Pension	OPEB
EEI-1	5.06%	5.07%	Other	Actuarial	6.00%	5.50%			6.50%	6.00%
EEI-2	5.51%	5.52%	Mercer	Bond Model	6.30%				7.50%	
EEI-3	5.80%	5.80%	Willis Towers Watson	BOND:Link	6.49%	4.10%	-17.2%	-10.8%	6.93%	5.00%
EEI-4	5.15%	5.15%	Aon Hewitt	AA Above Median	6.50%	5.13%	-20.7%	-12.5%	6.50%	5.13%
EEI-5	5.60%	5.65%	Willis Towers Watson	BOND:Link	5.75%		-6.6%		6.50%	
EEI-6	5.00%	5.00%	Willis Towers Watson	BOND:Link	5.90%	4.90%	-15.5%	-17.0%	5.90%	4.90%
EEI-7	5.54%	5.51%	Willis Towers Watson	BOND:Link	7.10%	4.80%	-20.0%	-16.0%	7.80%	6.40%
EEI-8	5.45%	5.35%	Willis Towers Watson	Rate:Link	7.00%	6.80%	-13.8%	-21.4%	6.75%	6.90%
EEI-9	5.70%	5.70%	Willis Towers Watson	BOND:Link	3.85%	3.40%	-19.0%	-18.0%	6.00%	5.30%
EEI-10	5.25%	5.18%	Aon Hewitt	AA Above Median	8.35%	4.63%	-13.4%		8.50%	5.63%
EEI-11	5.25%	5.25%	FTSE (former Citigroup)	Pension Discount	8.00%	8.00%	-12.0%	-12.0%	7.50%	7.50%
EEI-12	5.49%	5.50%	Willis Towers Watson	BOND:Link	6.88%	7.00%	-13.4%	-13.6%	6.63%	6.50%
EEI-13	4.94%	4.97%	Aon Hewitt	AA Above Median	4.80%	5.72%	-18.0%	-13.5%	7.00%	7.30%
EEI-14	4.93%	5.19%	Aon Hewitt	AA-AAA Bond Universe	4.87%	5.61%	-23.4%	-21.1%	6.05%	6.94%
EEI-15		4.99%	FTSE (former Citigroup)	Pension Discount		7.20%		-15.7%		
EEI-16	5.72%	2.96%	Willis Towers Watson	Rate:Link	7.00%	7.00%	-19.5%	-5.3%	7.50%	7.00%
EEI-17	5.47%	5.45%	Prudential	Above Mean	6.75%	6.75%			7.00%	7.00%
EEI-18	5.56%	5.58%	Willis Towers Watson	Rate:Link	5.00%	5.50%	-21.1%	-22.3%	6.70%	6.95%
EEI-19	5.19%	5.19%	Aon Hewitt	AA Only Above Median	6.80%	6.40%	-19.5%	-16.8%	7.60%	7.20%
EEI-20	5.23%	5.16%	Aon Hewitt	AA Above Median	7.50%	7.50%	-19.5%	-13.7%	7.50%	7.50%
EEI-21	5.50%	5.50%	Willis Towers Watson	BOND:Link	5.25%	5.50%	-16.8%	-19.4%	7.50%	7.25%
EEI-22	5.19%	5.21%	Aon Hewitt	AA Above Median	6.50%	6.50%	-10.0%	-10.0%	7.20%	7.20%
EEI-23	5.53%	5.51%	Willis Towers Watson	Rate:Link	7.20%	6.50%	-18.7%	-11.3%		
EEI-24	5.17%	5.14%	Aon Hewitt	AA Above Median	4.25%	1.70%	4.3%	1.7%	6.00%	3.10%
EEI-25	5.42%	5.47%	Willis Towers Watson	BOND:Link	6.75%	4.84%	-22.8%	-11.0%	6.75%	6.75%
EEI-26	5.20%	5.19%	Aon Hewitt	AA Only Above Median	8.25%	8.25%	-6.5%	-10.5%	8.25%	8.25%
EEI-27	6.10%	6.11%	Willis Towers Watson	BOND:Link	5.80%	4.70%				
EEI-28	5.69%	5.68%	Willis Towers Watson	BOND:Link	6.00%	6.00%	-10.0%	-10.0%	6.50%	7.00%
EEI-29	5.60%	5.60%	Willis Towers Watson	BOND:Link	6.50%	6.50%			7.20%	
EEI-30	5.67%	5.66%	Willis Towers Watson	BOND:Link	7.25%	7.25%	-19.9%		7.25%	7.25%
EEI-31	5.45%	5.45%	Other	Bond model	7.40%	6.00%	-13.5%	-16.2%	7.40%	6.00%
EEI-32	5.24%	5.20%	Aon Hewitt	AA Above Median	6.75%	6.25%			7.00%	6.25%
EEI-33	5.54%	5.59%	Willis Towers Watson	Other	7.00%	7.85%	7.0%	7.9%	7.00%	7.85%
EEI-34	5.60%	5.60%	Willis Towers Watson	BOND:Link	6.50%	3.67%	-20.8%	-11.6%	6.75%	5.00%
EEI-35	5.55%	5.55%	Willis Towers Watson	BOND:Link	6.50%	6.50%	-25.7%	-14.4%	6.75%	6.75%
EEI-36	5.44%	5.61%	Willis Towers Watson	BOND:Link	5.27%		-16.0%		6.00%	
EEI-37	5.52%	5.50%	Willis Towers Watson	Rate:Link	5.50%	3.45%	-20.7%	-17.2%	6.10%	4.55%
EEI-38	5.70%	5.70%	Willis Towers Watson	BOND:Link	7.00%	8.35%	-21.5%	-17.7%		
EEI-39	5.72%	5.71%	Willis Towers Watson	BOND:Link			6.80%	4.00%		
EEI-40	5.18%	5.13%	Other	Proprietary	6.00%	5.90%	7.50%	6.15%	6.15%	6.15%
EEI-41	5.70%	5.60%	Willis Towers Watson	BOND:Link	4.30%	5.50%	-18.70%	-17.40%	6.35%	6.80%
EEI-42	5.05%	4.97%	Aon Hewitt	AA Only Bond Universe	7.35%		-14.40%		8.00%	
EEI-43	5.81%	5.82%	Willis Towers Watson	BOND:Link	7.25%	6.00%	-25.70%		8.25%	7.00%
2022-23 Results										
Average	**5.44%**	**5.36%**			**6.4%**	**5.9%**	**-14.7%**	**-12.1%**	**7.0%**	**6.4%**
Quartile 0% (Min)	4.93%	2.96%			3.9%	1.7%	-25.7%	-22.3%	5.9%	3.1%
Quartile 25%	5.21%	5.19%			5.8%	5.0%	-20.2%	-17.1%	6.5%	6.0%
Quartile 50% (Media	**5.50%**	**5.50%**			**6.5%**	**6.0%**	**-17.6%**	**-13.6%**	**7.0%**	**6.8%**
Quartile 75%	5.60%	5.60%			7.0%	6.8%	-13.0%	-10.6%	7.5%	7.2%
Quartile 100% (Max)	6.10%	6.11%			8.4%	8.4%	7.5%	7.9%	8.5%	8.3%
# Responses	**42**	**43**	**43**	**43**	**41**	**38**	**36**	**31**	**38**	**33**

Xcel Energy Discount Rate Benchmarks

	December 31, 2021 Bond Matching[1]	December 31, 2022 Bond Matching[1]	Change From December 31, 2021
Xcel Energy Pension Plan	3.07%	5.80%	2.73%
NCE Non-bargaining Plan	3.02%	5.80%	2.78%
SPS Bargaining Plan	3.14%	5.80%	2.66%
PSCo Bargaining Plan	3.14%	5.82%	2.68%
All Pension Plans Combined	3.08%	5.80%	2.72%
Nonqualified Pension	2.67%	5.77%	3.10%
Post-Retirement Medical Plan	3.09%	5.80%	2.71%
Workers Compensation and LTD[2]	2.93%	5.79%	2.86%
ICE BofA US Corporate AAA-AA 15+ Index	2.81%	5.06%	2.25%
10-Year Treasuries	1.52%	3.88%	2.36%
30-Year Treasuries	1.90%	3.97%	2.07%

[1]Based on WTW BOND:Link model. The results are based on the bond model parameters summarized in our December 18, 2019 memo.
[2]Fiscal year 2023 budget estimates will use a discount rate of 5.79% until 2023 census data is available to determine actual discount rate for 2023 cost.

Xcel Energy Inc.
2023 Expected Return on Assets (EROA) Analysis[1]

Modeled Asset Class[2]	WTW October 1, 2022 Capital Market Assumptions[2] 10-Yr Arithmetic Returns	20-Yr Arithmetic Returns	2023 Target Asset Allocations XEPP	PSCO	SPS	NCE	MPT	VEBA (Includes EIS Allocation)[3]
Large Cap Stocks	8.89%	8.51%	21.50%	18.20%	18.20%	21.50%	19.90%	3.04%
Small Cap Stocks	9.12%	8.78%	1.90%	1.60%	1.60%	1.90%	1.75%	1.21%
All US Stocks	9.01%	8.61%	0.00%	0.00%	0.00%	0.00%	0.00%	6.93%
International Stocks	9.56%	8.96%	8.35%	7.05%	7.05%	8.35%	7.80%	3.96%
Emerging Market Stocks	11.55%	11.61%	4.00%	3.40%	3.40%	4.00%	3.75%	0.00%
High-Yield Bonds	6.04%	6.10%	5.85%	4.95%	4.95%	5.85%	5.50%	7.42%
Emerging Market Debt	7.12%	7.18%	3.90%	3.30%	3.30%	3.90%	3.60%	3.73%
Hedge Fund of Funds	6.52%	6.47%	5.20%	4.40%	4.40%	5.20%	4.80%	12.43%
Private Equity	13.39%	13.37%	6.50%	5.50%	5.50%	6.50%	6.00%	0.00%
Private Credit[4]	4.65%	4.71%	2.60%	2.20%	2.20%	2.60%	2.40%	0.00%
Real Estate	6.85%	8.08%	5.20%	4.40%	4.40%	5.20%	4.80%	0.00%
Aggregate Bonds	4.43%	4.62%	0.00%	0.00%	0.00%	0.00%	0.00%	60.15%
Long High Quality Bonds[5]	5.70%	5.99%	27.90%	36.30%	36.30%	27.90%	31.80%	0.00%
25-Year Zero Coupon Bonds[5]	4.84%	6.42%	5.10%	6.70%	6.70%	5.10%	5.90%	0.00%
Cash Equivalents	3.31%	3.42%	2.00%	2.00%	2.00%	2.00%	2.00%	1.13%
Total			100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

	XEPP	PSCO	SPS	NCE	MPT	VEBA
Expected Geometric Portfolio Returns (before administrative expenses)						
WTW - 10-year - passive	7.04%	6.70%	6.70%	7.04%	6.81%	5.41%
WTW - 20-year - passive	6.99%	6.72%	6.72%	6.99%	6.85%	5.35%
Expected 2023 Administrative Expenses[6]	-0.27%	-0.65%	-0.21%	-0.78%	-0.43%	-0.18%
2022 EROA Assumption	6.60%	6.35%	6.35%	6.60%	6.49%	4.10%
Increase/(Decrease) from Asset Allocation change (20-year basis)	-0.10%	-0.04%	-0.04%	-0.10%	-0.07%	0.08%
Increase/(Decrease) in WTW Model Returns from 2022 (20-year basis)	1.09%	1.26%	1.26%	1.09%	1.15%	1.33%
Decrease/(Increase) in Administrative Expenses from 2022	-0.06%	-0.46%	-0.03%	-0.53%	-0.23%	-0.10%
Combined Changes from 2022	0.93%	0.76%	1.19%	0.46%	0.85%	1.31%
2023 EROA Assumption Selected by Xcel Energy[7]	**7.25%**	**6.50%**	**7.00%**	**6.75%**	**6.93%**	**5.00%**
Change in EROA assumption	0.65%	0.15%	0.65%	0.15%	0.44%	0.90%

[1] All returns are net of investment expenses, and assume passive investments (i.e., do not include alpha)
[2] See WTW Expected Return Estimator U.S. Capita Market Assumptions as of October 1, 2022 for more details
[3] EIS portfolio allocations based on information received from Xcel Energy on January 24, 2023
[4] Private credit modeled as high-yield bonds
[5] Immunizing portfolio allocated between long high quality bonds and 25-year zero coupon bonds based on information received from Xcel Energy on October 27, 2021
[6] ASC 715 expected return assumption is net of administrative expenses as these are paid from plan assets. Expected administrative expenses equal annualized amounts paid through September 2022 plus expected changes in PBGC premiums. VEBA assumption is a high-level estimate and includes 10bps for presence of cash. See estimated 2023 administrative fee details exhibit for
[7] See Xcel Energy assumption memo for more information on the assumption selection process and additional information considered.

XCEL ENERGY INC. - Qualified Pension Plans
Cost by Legal Entity
($ in Thousands)

EXHIBIT I
Page 2 of 6

				Amortizations								
2024	Service Cost	Interest Cost	Expected Return on Assets	Prior Service Cost	Net (Gain)/Loss	Net Cost	Settlement Charge [1]	Aggregate Cost Compensation Method	Aggregate Cost 20-year Amortization Method	January 1 Prepaid (Accrued)	Contribution	PBO
Xcel Energy Pension Plan (XEPP)												
Discontinued Operations[2]	-	3,031	(3,919)	-	1,583	695	-	N/A	N/A	31,595	1,793	54,877
Xcel Energy Nuclear	3,784	4,073	(5,266)	(214)	(376)	2,001	-	3,356	3,435	(8,607)	2,403	73,552
NSP - MN	17,264	30,690	(39,685)	222	11,542	20,033	-	25,442	26,044	231,656	18,220	557,597
NSP - WI	3,790	6,111	(7,901)	(21)	1,556	3,535	-	N/A		30,949	3,608	110,407
Xcel Services[3]	23,062	32,067	(41,461)	(985)	3,818	16,501	-	N/A	N/A	70,929	18,976	580,708
Total XEPP	47,900	75,972	(98,232)	(998)	18,123	42,765	-	28,798	29,479	356,522	45,000	1,377,141

[1] Settlement accounting may be required if lump sum benefit payments exceed the sum of service cost and interest on a plan by plan basis. No settlements have been estimated at this time.
[2] Includes NRG, BMG, Viking, Natro Gas, Utility Engineering, Seren, Quixx, Crockett, QPS, MEC, and XEPC (former EMI)
[3] Includes Eloigne

Assumptions

Discount Rate - U.S. GAAP	
XEPP	5.80%
NCE	5.80%
SPS	5.80%
PSCo	5.82%
Discount Rate - Aggregate Normal Cost	7.25%
Salary Scale	4.25%
Expected Return on Assets	
XEPP	7.25%
NCE	6.75%
SPS	7.00%
PSCo	6.50%
Assumed Mortality Table	
Bargaining Participants	Pri-2012 Blue Collar, as adjusted for 2019 Xcel Energy mortality study, projected with generational mortality improvements using an adjusted SOA MP-2020 methodology
Non-bargaining Participants	Pri-2012 White Collar, as adjusted for 2019 Xcel Energy mortality study, projected with generational mortality improvements using an adjusted SOA MP-2020 methodology

See June 2, 2023 letter for additional information on data, assumptions, methods, models and plan provisions.
Contributions already made are allocated in accordance with the January 3, 2023 contribution directives.

XCEL ENERGY INC. - Postretirement Benefits
U.S. GAAP Cost Estimates by Legal Entity
($ in Thousands)

EXHIBIT III
Page 2 of 6

				Amortizations				
2024	Service Cost	Interest Cost	Expected Return on Assets	Prior Service Cost	Net (Gain)/Loss	Net Cost	January 1 Prepaid (Accrued)	Contribution
Discontinued Operations[1]	-	249	(71)	-	28	206	(2,063)	512
Xcel Energy Nuclear	4	36	-	-	(18)	22	(1,304)	28
NSP - MN[2]	67	2,388	(247)	-	418	2,626	(22,900)	5,026
NSP - WI	16	428	(45)	-	88	487	(3,528)	803
PSCo	411	15,703	(14,859)	-	1,362	2,617	76,792	2,617
SPS[3]	475	1,413	(1,693)	-	(522)	(327)	(10,302)	-
Xcel Services[3]	19	1,127	(65)	-	237	1,318	(10,102)	1,942
Total Xcel Energy	992	21,344	(16,980)	-	1,593	6,949	26,593	10,928

[1]Includes NRG, BMG, Viking, Natrogas, Cheyenne, Quixx, UE and XEPC (former EMI).

[2]Includes Eloigne and Seren.

[3]Includes Executive Life Insurance benefits.

Assumptions

Discount Rate	5.80%		
Expected Return on Assets	5.00%		
Medical Trend	Pre-Medicare	Post-Medicare	Medicare Part D
Initial (2023)	6.50%	5.50%	4.00%
Ultimate	4.50%	4.50%	2.50%
Year Ultimate Reached	2030	2030	2030

Assumed Mortality Table

Bargaining: PriH-2012 Blue Collar headcount-weighted table adjusted for Xcel Energy mortality study, projected with generational mortality improvements using an adjusted SOA MP-2020 methodology.

Non-bargaining: PriH-2012 White Collar headcount-weighted table adjusted for Xcel Energy mortality study, projected with generational mortality improvements using an adjusted SOA MP-2020 methodology.

Contributions for PSCo and SPS are assumed equal to the net cost, but not less than zero. Contributions for other legal entities are assumed equal to the expected benefit payments.

See June 2, 2023 letter for additional information on data, assumptions, methods, models and plan provisions.

Exhibit VI
Page 1 of 1

Xcel Energy Inc. - LTD and Workers' Compensation
Benefit Cost Estimates by Legal Entity
($ in Thousands)

Fiscal Year Ending	2022	2023	2024	2025	2026	2027	2028
U.S. GAAP	Actual	Actual	Budget	Budget	Budget	Budget	Budget
Discount Rate- Workers' Compensation	2.93%	5.80%	5.80%	5.80%	5.80%	5.80%	5.80%
Former NSP - Workers' Compensation [1]							
MN/SD	836	(841)	260	245	232	222	210
MI/WI	444	412	1	2	2	1	1
Subtotal	1,280	(429)	261	247	234	223	211
Former NCE - Workers' Compensation [1]							
Colorado - PSCo	(26)	(78)	40	39	36	33	32
Deductible States - Workers' Compensation							
Deductible States - SPS (KS, OK, NM, and TX)	-	-	-	-	-	-	-
Total Xcel Energy Workers' Compensation	**1,254**	**(507)**	**301**	**286**	**270**	**256**	**243**
Discount Rate - LTD Income	2.93%	5.80%	5.80%	5.80%	5.80%	5.80%	5.80%
LTD Income							
Discontinued Operations - Cheyenne	(18)	(20)	1	1	-	-	-
Nuclear Operations	-	(338)	10	8	6	5	4
NSP-MN	(1,065)	(95)	155	132	115	99	86
NSP-WI	(575)	(38)	21	17	14	12	11
PSCo	104	(27)	23	19	15	12	11
SPS	30	(6)	4	2	2	-	-
Utility Engineering	(5)	(5)	1	1	1	1	-
Xcel Services	57	15	4	3	3	2	1
Total Xcel Energy LTD Income	**(1,472)**	**(514)**	**219**	**183**	**156**	**131**	**113**
Total Xcel Energy U.S. GAAP	**(218)**	**(1,021)**	**520**	**469**	**426**	**387**	**356**

[1] *Results for former NSP states include income replacement and medical benefits as well as reserve for bankrupt insurers. Colorado results include reserve for bankrupt insurers.*
See June 2, 2023 letter for additional information on data, assumptions, models, methods, and plan provisions.

	Qualified Pension	Retiree Medical	FAS 112 Long-Term Disability	FAS 112 Workers Compensation
NSPM				
Total Cost from Actuarial Report	25,442,000	2,626,000	155,000	260,000
Percent to NSPM Gas O&M	8.28%	8.28%	8.28%	8.13%
Amount to NSPM Gas O&M	2,105,721	217,342	12,829	21,140
Percent to State of Minnesota	89.80%	89.80%	89.80%	88.16%
Amount to State of Minnesota	1,890,986	195,178	11,520	18,637
Xcel Energy Services				
Total Cost from Actuarial Report	16,501,000	1,318,000	4,000	
Percent to NSPM Gas O&M	2.55%	2.55%	2.55%	
Amount to NSPM Gas O&M	421,274	33,649	102	
Percent to State of Minnesota	89.80%	89.80%	89.80%	
Amount to State of Minnesota	378,314	30,217	92	
Affiliate Charges	17	2.00	-	1.00
Total NSPM Gas O&M, State of Minnesota	**2,269,317**	**225,398**	**11,612**	**18,638**

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2022 or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from______to ______

001-31387
(Commission File Number)

Northern States Power Company
(Exact name of registrant as specified in its charter)

Minnesota	**41-1967505**
(State or Other Jurisdiction of Incorporation or Organization)	(IRS Employer Identification No.)
414 Nicollet Mall Minneapolis Minnesota	**55401**
(Address of Principal Executive Offices)	(Zip Code)

(612) 330-5500
(Registrant's Telephone Number, Including Area Code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
N/A	N/A	N/A

Securities registered pursuant to section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. ☒ Yes ☐ No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. ☐ Yes ☒ No

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. ☒ Yes ☐ No

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). ☒ Yes ☐ No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer", "accelerated filer", "smaller reporting company", and "emerging growth company" in Rule 12b-2 of the Exchange Act. ☐ Large accelerated filer ☐ Accelerated filer ☒ Non-accelerated filer ☐ Smaller reporting company ☐ Emerging growth company

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C.7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☐

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). ☐ Yes ☒ No

As of Feb. 23, 2023, 1,000,000 shares of common stock, par value $0.01 per share, were outstanding, all of which were held by Xcel Energy Inc., a Minnesota corporation.

DOCUMENTS INCORPORATED BY REFERENCE

The information required by Item 14 of Form 10-K is set forth under the heading "Independent Registered Public Accounting Firm – Audit and Non-Audit Fees" in Xcel Energy Inc.'s definitive Proxy Statement for the 2023 Annual Meeting of Shareholders which definitive Proxy Statement is expected to be filed with the SEC on or about April 11, 2023. Such information set forth under such heading is incorporated herein by this reference hereto.

Northern States Power Company meets the conditions set forth in General Instructions I(1)(a) and (b) of Form 10-K and is therefore filing this form with the reduced disclosure format permitted by General Instruction I(2).

TABLE OF CONTENTS

This Form 10-K is filed by NSP-Minnesota. NSP-Minnesota is a wholly owned subsidiary of Xcel Energy Inc. Additional information on Xcel Energy is available in various filings with the SEC. This report should be read in its entirety.

PART I

Item I — Business

Definitions of Abbreviations

Xcel Energy Inc.'s Subsidiaries and Affiliates (current and former)

NSP-Minnesota	Northern States Power Company, a Minnesota corporation
NSP System	The electric production and transmission system of NSP-Minnesota and NSP-Wisconsin operated on an integrated basis and managed by NSP-Minnesota
NSP-Wisconsin	Northern States Power Company, a Wisconsin corporation
PSCo	Public Service Company of Colorado
SPS	Southwestern Public Service Company
Utility subsidiaries	NSP-Minnesota, NSP-Wisconsin, PSCo and SPS
Xcel Energy	Xcel Energy Inc. and its subsidiaries

Federal and State Regulatory Agencies

DOC	Minnesota Department of Commerce
DOE	United States Department of Energy
DOT	United States Department of Transportation
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
IRS	Internal Revenue Service
MPUC	Minnesota Public Utilities Commission
NDPSC	North Dakota Public Service Commission
NERC	North American Electric Reliability Corporation
NRC	Nuclear Regulatory Commission
PHMSA	Pipeline and Hazardous Materials Safety Administration
SEC	Securities and Exchange Commission

Electric, Purchased Gas and Resource Adjustment Clauses

CIP	Conservation improvement program
DSM	Demand side management
GUIC	Gas utility infrastructure cost rider
RES	Renewable energy standard

Other

AFUDC	Allowance for funds used during construction
ALJ	Administrative Law Judge
AMT	Alternative minimum tax
ARO	Asset retirement obligation
ASC	Financial Accounting Standards Board Accounting Standards Codification
C&I	Commercial and Industrial
CapX2020	Alliance of electric cooperatives, municipals and investor-owned utilities in the upper Midwest involved in a joint transmission line planning and construction effort
CCR	Coal combustion residuals
CCR Rule	Final rule (40 CFR 257.50 - 257.107) published by the EPA regulating the management, storage and disposal of CCRs as a nonhazardous waste
CEO	Chief executive officer
CFO	Chief financial officer
CON	Certificate of Need
CWIP	Construction work in progress
D.C. Circuit	United States Court of Appeals for the District of Columbia Circuit
DECON	Decommissioning method where radioactive contamination is removed and safely disposed of at a requisite facility or decontaminated to a permitted level
EMANI	European Mutual Association for Nuclear Insurance
ETR	Effective tax rate
FTR	Financial transmission right
GAAP	Generally accepted accounting principles
GE	General Electric
GHG	Greenhouse gas
INPO	Institute of Nuclear Power Operations
IPP	Independent power producing entity
IRA	Inflation Reduction Act
ISO	Independent System Operator
ITC	Investment tax credit
MGP	Manufactured gas plant
MISO	Midcontinent Independent System Operator, Inc.
Moody's	Moody's Investor Services
Native load	Customer demand of retail and wholesale customers that a utility has an obligation to serve under statute or long-term contract
NAV	Net asset value
NEIL	Nuclear Electric Insurance Ltd.
NOL	Net operating loss
O&M	Operating and maintenance
OAG	Minnesota Office of the Attorney General
PFAS	Per- and PolyFluoroAlkyl Substances
PI	Prairie Island nuclear generating plant
PPA	Purchased power agreement
PTC	Production tax credit
REC	Renewable energy credit
RFP	Request for proposal
ROE	Return on equity
ROU	Right-of-use
RTO	Regional Transmission Organization
S&P	Standard & Poor's Global Ratings
SERP	Supplemental executive retirement plan
TCJA	2017 federal tax reform enacted as Public Law No: 115-97, commonly referred to as the Tax Cuts and Jobs Act
TO	Transmission owner
VaR	Value at Risk
VIE	Variable interest entity

Measurements

Bcf	Billion cubic feet
KV	Kilovolts
KWh	Kilowatt hours
MMBtu	Million British thermal units
MW	Megawatts
MWh	Megawatt hours

Where to Find More Information

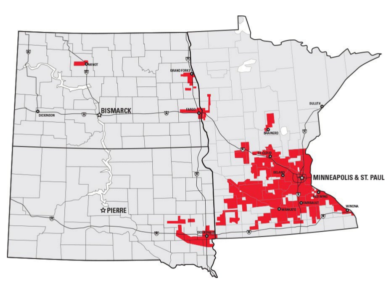
NSP-Minnesota is a wholly owned subsidiary of Xcel Energy Inc., and Xcel Energy's website address is www.xcelenergy.com. Xcel Energy makes available, free of charge through its website, its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after the reports are electronically filed with or furnished to the SEC. The SEC maintains an internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically at http://www.sec.gov. The information on Xcel Energy's website is not a part of, or incorporated by reference in, this annual report on Form 10-K.

Forward-Looking Statements

Except for the historical statements contained in this report, the matters discussed herein are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements, including those relating to future sales, future expenses, future tax rates, future operating performance, estimated base capital expenditures and financing plans, projected capital additions and forecasted annual revenue requirements with respect to rider filings, expected rate increases to customers, expectations and intentions regarding regulatory proceedings, and expected impact on our results of operations, financial condition and cash flows of resettlement calculations and credit losses relating to certain energy transactions, as well as assumptions and other statements are intended to be identified in this document by the words “anticipate,” “believe,” “could,” “estimate,” “expect,” “intend,” “may,” “objective,” “outlook,” “plan,” “project,” “possible,” “potential,” “should,” “will,” “would” and similar expressions. Actual results may vary materially. Forward-looking statements speak only as of the date they are made, and we expressly disclaim any obligation to update any forward-looking information. The following factors, in addition to those discussed elsewhere in this Annual Report on Form 10-K for the fiscal year ended Dec. 31, 2022 (including risk factors listed from time to time by NSP-Minnesota in reports filed with the SEC, including “Risk Factors” in Item 1A of this Annual Report on Form 10-K), could cause actual results to differ materially from management expectations as suggested by such forward-looking information: operational safety, including our nuclear generation facilities and other utility operations; successful long-term operational planning; commodity risks associated with energy markets and production; rising energy prices and fuel costs; qualified employee work force and third-party contractor factors; violations of our Codes of Conduct; our ability to recover costs; changes in regulation; reductions in our credit ratings and the cost of maintaining certain contractual relationships; general economic conditions, including recessionary conditions, inflation rates, monetary fluctuations, supply chain constraints and their impact on capital expenditures and/or the ability of NSP-Minnesota to obtain financing on favorable terms; availability or cost of capital; our customers’ and counterparties’ ability to pay their debts to us; assumptions and costs relating to funding our employee benefit plans and health care benefits; tax laws; uncertainty regarding epidemics, the duration and magnitude of business restrictions including shutdowns (domestically and globally), the potential impact on the workforce, including shortages of employees or third-party contractors due to quarantine policies, vaccination requirements or government restrictions, impacts on the transportation of goods and the generalized impact on the economy; effects of geopolitical events, including war and acts of terrorism; cyber security threats and data security breaches; seasonal weather patterns; changes in environmental laws and regulations; climate change and other weather events; natural disaster and resource depletion, including compliance with any accompanying legislative and regulatory changes; costs of potential regulatory penalties; regulatory changes and/or limitations related to the use of natural gas as an energy source; challenging labor market conditions and our ability to attract and retain a qualified workforce; and our ability to execute on our strategies or achieve expectations related to environmental, social and governance matters including as a result of evolving legal, regulatory and other standards, processes, and assumptions, the pace of scientific and technological developments, increased costs, the availability of requisite financing, and changes in carbon markets.

Company Overview

Electric customers	1.5 million
Natural gas customers	0.5 million
Total assets	$23.7 billion
Rate Base (estimated)	$15.1 billion
ROE (net income / average stockholder's equity)	8.76%
Electric generating capacity	8,949 MW
Gas storage capacity	17.1 Bcf
Electric transmission lines (conductor miles)	33,000 miles
Electric distribution lines (conductor miles)	82,000 miles
Natural gas transmission lines	78 miles
Natural gas distribution lines	11,000 miles



NSP-Minnesota was incorporated in 2000 under the laws of Minnesota. NSP-Minnesota conducts business in Minnesota, North Dakota and South Dakota and has electric operations in all three states including the generation, purchase, transmission, distribution and sale of electricity. NSP-Minnesota and NSP-Wisconsin electric operations are managed on the NSP System. NSP-Minnesota also purchases, transports, distributes and sells natural gas to retail customers and transports customer-owned natural gas in Minnesota and North Dakota.

Electric Operations

Electric operations consist of energy supply, generation, transmission and distribution activities. NSP-Minnesota had electric sales volume of 47,189 (millions of KWh), 1.5 million customers and electric revenues of $5,617 million for 2022.

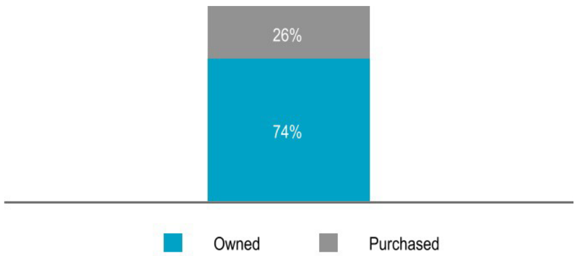
Electric Operations (percentage of total)	Sales Volume	Number of Customers	Revenues
Residential	23 %	89 %	26 %
C&I	48	10	42
Other	29	1	32

Retail Sales/Revenue Statistics [(a)]

	2022	2021
KWH sales per retail customer	21,604	21,644
Revenue per retail customer	$ 2,508	$ 2,507
C&I revenue per KWh	10.57 ¢	10.49 ¢
Total retail revenue per KWh	11.61 ¢	11.58 ¢

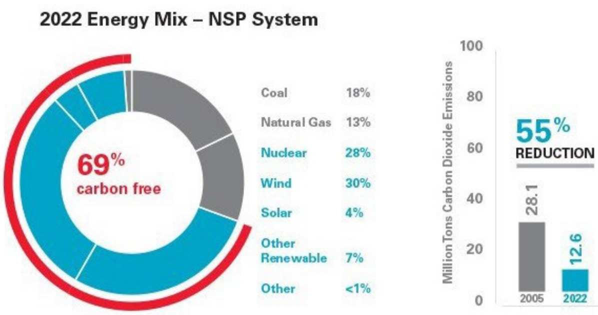
[(a)] See Note 6 to the consolidated financial statements for further information.

Owned and Purchased Energy Generation — 2022



Electric Energy Sources

Total electric energy generation by source for the year ended Dec. 31:



Carbon–Free — NSP System

The NSP System's carbon–free energy portfolio includes nuclear, wind, hydroelectric, biomass and solar power from both owned generating facilities and PPAs. Carbon–free percentages will vary year over year based on system additions, commodity costs, weather, system demand and transmission constraints.

See Item 2 — Properties for further information.

Wind

Owned — Owned and operated wind farms with corresponding capacity:

2022		2021	
Wind Farms	Capacity (MW) [a]	Wind Farms	Capacity (MW) [b]
16	2,352	14	2,031

(a) Summer 2022 net dependable capacity.
(b) Summer 2021 net dependable capacity.

PPAs — Number of PPAs with capacity range:

2022		2021	
PPAs	Range (MW)	PPAs	Range (MW)
129	1 — 206	128	1 — 206

Current wind capacity for owned wind farms and PPAs was 4,515 MW and 3,997 MW in 2022 and 2021, respectively.

In 2022, the average cost of wind energy was $18 per MWh for owned generation and $37 per MWh under existing PPAs. In 2021, the average cost of wind energy was $25 per MWh for owned generation and $37 per MWh under existing PPAs.

Wind Development — The NSP System placed approximately 500 MW of owned wind and approximately 220 MW of PPAs into service during 2022:

Project	Capacity (MW)
Dakota Range	298 [(a)(b)]
Nobles Repower	200 [(a)(b)]
Rock Aetna	20 [(a)(b)]
PPA	~220 [(c)]

(a) Summer 2022 net dependable capacity.
(b) Values disclosed are the maximum generation levels. Capacity is attainable only when wind conditions are sufficiently available.
(c) Based on contracted capacity.

The NSP System currently has approximately 550 MW of owned wind under development or being repowered.

Project	Capacity (MW)	Estimated Completion
Northern Wind	100	2023 [(a)]
Grand Meadow Repower	100	2023
Border Winds Repower	150	2025
Pleasant Valley Repower	200	2025

(a) Placed in service in January 2023.

Solar

PPAs — Solar PPAs capacity by type:

Type	Capacity (MW)
Distributed Generation	1,074
Utility-Scale	269
Total	1,343

The average cost of solar energy under existing PPAs was $79 per MWh and $90 per MWh in 2022 and 2021, respectively.

Solar Development — In September 2022, the MPUC approved NSP-Minnesota's proposal to add 460 MW of solar facilities at the Sherco site. The project is expected to cost approximately $690 million (two phases to be completed in 2024 and 2025). As a result of the IRA, the levelized cost of the project is expected to be approximately 30% lower than previously estimated.

Nuclear

The NSP System has two nuclear plants (owned by NSP-Minnesota) with approximately 1,700 MW of total 2022 net summer dependable capacity. Our nuclear fleet has become one of the best performing and dependable in the nation, as rated by both the NRC and INPO. NSP-Minnesota secures contracts for uranium concentrates, uranium conversion, uranium enrichment and fuel fabrication to operate its nuclear plants. NSP-Minnesota uses varying contract lengths as well as multiple producers for uranium concentrates, conversion services and enrichment services to minimize potential impacts caused by supply interruptions due to geographical and world political issues.

Nuclear Fuel Cost — Delivered cost per MMBtu of nuclear fuel consumed for owned electric generation and the percentage of total fuel requirements (nuclear, natural gas and coal):

	Nuclear	
	Cost	Percent
2022	$ 0.76	51 %
2021	0.77	50

Other

The NSP System's other carbon-free energy portfolio includes hydro from owned generating facilities.

See Item 2 — Properties for further information.

Fossil Fuel — NSP System

The NSP System's fossil fuel energy portfolio includes coal and natural gas power from both owned generating facilities and PPAs.

See Item 2 — Properties for further information.

Coal

The NSP System owns and operates coal units with approximately 2,400 MW of total capacity, which provided 18% of NSP System's energy mix in 2022. All of these units are approved for retirement by 2030.

Approved early coal plant retirements:

Year	Plant Unit	Capacity (MW)
2023	Sherco 2	682
2026	Sherco 1	680
2028	A.S. King	511
2030	Sherco 3	517 (a)

(a) Based on the NSP System's ownership interest.

Coal Fuel Cost — Delivered cost per MMBtu of coal consumed for owned electric generation and the percentage of total fuel requirements (nuclear, natural gas and coal):

	Coal (a)	
	Cost	Percent
2022	$ 2.27	37 %
2021	1.95	34

(a) Includes refuse-derived fuel and wood.

Natural Gas

The NSP System has eight natural gas plants with approximately 2,800 MW of total capacity, which provided 13% of NSP System's energy mix in 2022.

Natural gas supplies, transportation and storage services for power plants are procured to provide an adequate supply of fuel. Remaining requirements are procured through a liquid spot market. Generally, natural gas supply contracts have variable pricing that is tied to natural gas indices. Natural gas supply and transportation agreements include obligations for the purchase and/or delivery of specified volumes or payments in lieu of delivery.

Natural Gas Cost — Delivered cost per MMBtu of natural gas consumed for owned electric generation and the percentage of total fuel requirements (nuclear, natural gas and coal):

	Natural Gas	
	Cost	Percent
2022 (a)	$ 7.58	12 %
2021	4.98	16

(a) Reflective of Winter Storm Uri.

Capacity and Demand

Uninterrupted system peak demand and occurrence date:

System Peak Demand (MW)			
2022		2021	
9,245	June 20	8,837	June 9

Transmission

Transmission lines deliver electricity over long distances from power sources to transmission substations closer to customers. A strong transmission system ensures continued reliable and affordable service, ability to meet state and regional energy policy goals, and support for a diverse generation mix, including renewable energy. NSP-Minnesota owns more than 32,000 of 44,000 conductor miles of transmission lines across the NSP System service territory.

NSP System plans to build approximately 1,100 additional conductor miles of transmission lines, primarily as part of the MISO Tranche 1 project estimated to be complete in 2028.

See Item 2 - Properties for further information.

Distribution

Distribution lines allow electricity to travel at lower voltages from substations directly to customers. NSP-Minnesota has a vast distribution network, owning and operating approximately 82,000 conductor miles of distribution lines across our service territory. To continue providing reliable, affordable electric service and enable more flexibility for customers, we are working to digitize the distribution grid, while at the same time keeping it secure.

See Item 2 - Properties for further information.

Natural Gas Operations

Natural gas operations consist of purchase, transportation and distribution of natural gas to end-use residential, C&I and transport customers. NSP-Minnesota had natural gas deliveries of 85,903 (thousands of MMBtu), 0.5 million customers and natural gas revenues of $1,022 million for 2022.

Natural Gas (percentage of total)	Deliveries	Number of Customers	Revenues
Residential	44 %	92 %	50 %
C&I	47	8	42
Transportation and other	9	<1	8

Sales/Revenue Statistics (a)

	2022	2021
MMBtu sales per retail customer	144	149
Revenue per retail customer	$ 1,726	$ 1,121
Residential revenue per MMBtu	13.34	8.56
C&I revenue per MMBtu	10.76	6.53
Transportation and other revenue per MMBtu	2.56	1.29

(a) See Note 6 to the consolidated financial statements for further information.

Capability and Demand

Natural gas supply requirements are categorized as firm or interruptible (customers with an alternate energy supply).

Maximum daily output (firm and interruptible) and occurrence date:

2022		2021 (a)	
MMBtu	Date	MMBtu	Date
867,385	Feb. 12	899,133	Feb. 11

(a) Reflective of Winter Storm Uri.

Natural Gas Supply and Cost

NSP-Minnesota seeks natural gas supply, transportation and storage alternatives to yield a diversified portfolio, which increases flexibility and decreases interruption and financial risks and economical rates. In addition, NSP-Minnesota conducts natural gas price hedging activities approved by its states' commissions.

Average delivered cost per MMBtu of natural gas for regulated retail distribution:

2022	2021 [(a)]
$ 7.00	$ 7.48

(a) Reflective of Winter Storm Uri.

NSP-Minnesota has natural gas supply transportation and storage agreements that include obligations for purchase and/or delivery of specified volumes or to make payments in lieu of delivery.

General

Seasonality

Demand for electric power and natural gas is affected by seasonal differences in the weather. In general, peak sales of electricity occur in the summer months and peak sales of natural gas occur in the winter months. As a result, the overall operating results may fluctuate substantially on a seasonal basis. Additionally, NSP-Minnesota's operations have historically generated less revenues and income when weather conditions are milder in the winter and cooler in the summer.

Competition

NSP-Minnesota is subject to public policies that promote competition and development of energy markets. NSP-Minnesota's industrial and large commercial customers have the ability to generate their own electricity. In addition, customers may have the option of substituting other fuels or relocating their facilities to a lower cost region.

Customers have the opportunity to supply their own power with distributed generation including solar generation and in most jurisdictions can currently avoid paying for most of the fixed production, transmission and distribution costs incurred to serve them.

Minnesota has incentives for the development of rooftop solar, community solar gardens and other distributed energy resources. Distributed generating resources are potential competitors to NSP-Minnesota's electric service business with these incentives and federal tax subsidies.

The FERC has continued to promote competitive wholesale markets through open access transmission and other means. NSP-Minnesota's wholesale customers can purchase their output from generation resources of competing suppliers or non-contracted quantities and use the transmission system of NSP-Minnesota on a comparable basis to serve their native load.

FERC Order No. 1000 established competition for ownership of certain new electric transmission facilities under Federal regulations. Some states have state laws that allow the incumbent a Right of First Refusal to own these transmission facilities.

FERC Order 2222 requires that RTO and ISO markets allow participation of aggregations of distributed energy resources. This order is expected to incentivize distributed energy resource adoption, however implementation is expected to vary by RTO/ISO and the near, medium, and long-term impacts of Order 2222 remain unclear.

NSP-Minnesota has franchise agreements with cities subject to periodic renewal; however, a city could seek alternative means to access electric power or gas, such as municipalization. No municipalization activities are occurring presently.

While facing these challenges, NSP-Minnesota believes its rates and services are competitive with alternatives currently available.

Governmental Regulations

Public Utility Regulation

See Item 7 for discussion of public utility regulation.

Environmental Regulation

Our facilities are regulated by federal and state agencies that have jurisdiction over air emissions, water quality, wastewater discharges, solid and hazardous wastes or substances. Certain NSP-Minnesota activities require registrations, permits, licenses, inspections and approvals from these agencies.

NSP-Minnesota has received necessary authorizations for the construction and continued operation of its generation, transmission and distribution systems. Our facilities strive to operate in compliance with applicable environmental standards and related monitoring and reporting requirements.

However, it is not possible to determine what additional facilities or modifications to existing or planned facilities will be required as a result of changes to regulations, interpretations or enforcement policies or what effect future laws or regulations may have. We may be required to incur expenditures in the future for remediation of historic and current operating sites and other waste treatment, storage and disposal sites.

There are significant environmental regulations to encourage use of clean energy technologies and regulate emissions of GHGs. NSP-Minnesota has undertaken numerous initiatives to meet current requirements and prepare for potential future regulations, reduce GHG emissions and respond to state renewable and energy efficiency goals. Future environmental regulations may result in substantial costs.

Emerging Environmental Regulation

Clean Air Act — In April 2022, the EPA proposed regulations under the "Good Neighbor" provisions of the Clean Air Act. The proposed rules establish an allowance trading program for NOx, potentially impacting fossil fuel generating facilities in Minnesota. Under the proposed rule, facilities without NOx controls will have to secure additional allowances, install NOx controls, or develop a strategy of operations that utilizes the existing allowance allocations. The EPA has indicated that it intends for the rule to be final and applicable in the first half of 2023. While the financial impacts of the proposed regulation are uncertain and dependent on market forces, NSP-Minnesota anticipates that the costs to the NSP System will be approximately $30 million annually and will be recoverable through regulatory mechanisms based on prior state commission practices.

In a June 2022 ruling, the United States Supreme Court held that an economy-wide approach to reducing greenhouse gas emissions from coal-fired power plants was not consistent with the Clean Air Act. Therefore, if the EPA proceeds with new rules, it cannot set a standard based on economy-wide generation shifting to other sources, such as renewable energy. It is anticipated that EPA will propose rules to limit GHG emissions from new and existing coal and natural gas-fired electric generating units in 2023. If any new rules require additional investment, NSP-Minnesota believes that the cost of these initiatives or replacement generation would be recoverable through rates based on prior state commission practices.

Coal Ash Regulation — In February 2023, the EPA entered into a Consent Decree, committing the agency to either issue new proposed rules by May 5, 2023, to regulate inactive CCR landfills under the CCR Rule for the first time, or to determine no such rules are necessary by that date. If proposed rules are issued in May, the EPA has committed to a May 2024 effective date for the new rules. Until proposed rules are issued, it is not certain what the impact will be on NSP-Minnesota, but we anticipate that additional inactive ash units could become regulated for the first time. It is also anticipated that the EPA may issue other CCR proposed rules in 2023 that further expand the scope of the CCR Rule.

Emerging Contaminants of Concern — PFAS are man-made chemicals that are widely used in consumer products and can persist and bio-accumulate in the environment. NSP-Minnesota does not manufacture PFAS but because PFAS are so ubiquitous in products and the environment, it may impact our operations. In September 2022, the EPA proposed to designate two types of PFAS as "hazardous substances" under the CERCLA, specifically perfluorooctanoic acid and perfluorooctanesulfonic acid. This proposed rule could result in new obligations for investigation and cleanup wherever PFAS are found to be present. The impact the proposed regulation may have on electric and gas utilities is currently uncertain.

Other

Our operations are subject to workplace safety standards under the Federal Occupational Safety and Health Act of 1970 ("OSHA") and comparable state laws that regulate the protection of worker health and safety. In addition, the Company is subject to other government regulations impacting such matters as labor, competition, data privacy, etc. Based on information to date and because our policies and business practices are designed to comply with all applicable laws, we do not believe the effects of compliance on our operations, financial condition or cash flows are material.

Employees

As of Dec. 31, 2022, NSP-Minnesota had 3,201 full-time employees and four part-time employees, of which 2,070 were covered under collective-bargaining agreements.

ITEM 1A — RISK FACTORS

Xcel Energy, which includes NSP-Minnesota, is subject to a variety of risks, many of which are beyond our control. Risks that may adversely affect the business, financial condition, results of operations or cash flows are described below. Although the risks are organized by heading, and each risk is described separately, many of the risks are interrelated. These risks should be carefully considered together with the other information set forth in this report and future reports that Xcel Energy files with the SEC. You should not interpret the disclosure of any risk factor to imply that the risk has not already materialized. While we believe we have identified and discussed below the key risk factors affecting our business, there may be additional risks and uncertainties that are not presently known or that are not currently believed to be significant that may adversely affect our business, financial condition, results of operations or cash flows in the future.

Oversight of Risk and Related Processes

NSP-Minnesota's Board of Directors is responsible for the oversight of material risk and maintaining an effective risk monitoring process. Management and the Board of Directors have responsibility for overseeing the identification and mitigation of key risks.

NSP-Minnesota maintains a robust compliance program and promotes a culture of compliance beginning with the tone at the top. The risk mitigation process includes adherence to our Code of Conduct and compliance policies, operation of formal risk management structures and overall business management. NSP-Minnesota further mitigates inherent risks through formal risk committees and corporate functions such as internal audit, and internal controls over financial reporting and legal.

Management identifies and analyzes risks to determine materiality and other attributes such as timing, probability and controllability. Identification and risk analysis occurs formally through risk assessment conducted by senior management, the financial disclosure process, hazard risk procedures, internal audit and compliance with financial and operational controls. Management also identifies and analyzes risk through the business planning process, development of goals and establishment of key performance indicators, including identification of barriers to implementing our strategy. The business planning process also identifies likelihood and mitigating factors to prevent the assumption of inappropriate risk to meet goals.

Management communicates regularly with the Board of Directors and its sole stockholder regarding risk. Senior management presents and communicates a periodic risk assessment to the Board of Directors, providing information on the risks that management believes are material, including financial impact, timing, likelihood and mitigating factors. The Board of Directors regularly reviews management's key risk assessments, which includes areas of existing and future macroeconomic, financial, operational, policy, environmental, safety and security risks.

The oversight, management and mitigation of risk is an integral and continuous part of the Board of Directors' governance of NSP-Minnesota. Processes are in place to confirm appropriate risk oversight, as well as identification and consideration of new risks.

Risks Associated with Our Business

Operational Risks

Our natural gas and electric generation/transmission and distribution operations involve numerous risks that may result in accidents and other operating risks and costs.

Our natural gas transmission and distribution activities include inherent hazards and operating risks, such as leaks, explosions, outages and mechanical problems. Our electric generation, transmission and distribution activities include inherent hazards and operating risks such as contact, fire and outages. These risks could result in loss of life, significant property damage, environmental pollution, impairment of our operations and substantial financial losses to employees, third-party contractors, customers or the public. We maintain insurance against most, but not all, of these risks and losses. The occurrence of these events, if not fully covered by insurance, could have a material effect on our financial condition, results of operations and cash flows as well as potential loss of reputation.

Other uncertainties and risks inherent in operating and maintaining NSP-Minnesota's facilities include, but are not limited to:

- Risks associated with facility start-up operations, such as whether the facility will achieve projected operating performance on schedule and otherwise as planned.
- Failures in the availability, acquisition or transportation of fuel or other supplies.
- Impact of adverse weather conditions and natural disasters, including, tornadoes, icing events, floods and droughts.
- Performance below expected or contracted levels of output or efficiency.
- Availability of replacement equipment.
- Availability of adequate water resources and ability to satisfy water intake and discharge requirements.
- Availability or changes to wind patterns.
- Inability to identify, manage properly or mitigate equipment defects.
- Use of new or unproven technology.
- Risks associated with dependence on a specific type of fuel or fuel source, such as commodity price risk, availability of adequate fuel supply and transportation and lack of available alternative fuel sources.
- Increased competition due to, among other factors, new facilities, excess supply, shifting demand and regulatory changes.

Additionally, compliance with existing and potential new regulations related to the operation and maintenance of our natural gas infrastructure could result in significant costs. The PHMSA is responsible for administering the DOT's national regulatory program to assure the safe transportation of natural gas, petroleum and other hazardous materials by pipelines. The PHMSA continues to develop regulations and other approaches to risk management to assure safety in design, construction, testing, operation, maintenance and emergency response of natural gas pipeline infrastructure. We have programs in place to comply with these regulations and systematically monitor and renew infrastructure over time, however, a significant incident or material finding of non-compliance could result in penalties and higher costs of operations.

Our natural gas and electric transmission and distribution operations are dependent upon complex information technology systems and network infrastructure, the failure of which could disrupt our normal business operations, which could have a material adverse effect on our ability to process transactions and provide services.

Our utility operations are subject to long-term planning and project risks.

Most electric utility investments are planned to be used for decades. Transmission and generation investments typically have long lead times and are planned well in advance of in-service dates and typically subject to long-term resource plans. These plans are based on numerous assumptions such as: sales growth, customer usage, commodity prices, economic activity, costs, regulatory mechanisms, customer behavior, available technology and public policy. Our long-term resource plan is dependent on our ability to obtain required approvals, develop necessary technical expertise, allocate and coordinate sufficient resources and adhere to budgets and timelines.

In addition, the long-term nature of both our planning processes and our asset lives are subject to risk. The electric utility sector is undergoing significant change (e.g., increases in energy efficiency, wider adoption of distributed generation and shifts away from fossil fuel generation to renewable generation). Customer adoption of these technologies and increased energy efficiency could result in excess transmission and generation resources, downward pressure on sales growth, and potentially stranded costs if we are not able to fully recover costs and investments.

The magnitude and timing of resource additions and changes in customer demand may not coincide with evolving customer preference for generation resources and end-uses, which introduces further uncertainty into long-term planning. Efforts to electrify the transportation and building sectors to reduce GHG emissions may result in higher electric demand and lower natural gas demand over time. Higher electric demand may require us to adopt new technologies and make significant transmission and distribution investments including advanced grid infrastructure, which increases exposure to overall grid instability and technology obsolescence. Evolving stakeholder preference for lower emissions from generation sources and end-uses, like heating, may impact our resource mix and put pressure on our ability to recover capital investments in natural gas generation and delivery. Multiple states may not agree as to the appropriate resource mix, which may lead to costs to comply with one jurisdiction that are not recoverable across all jurisdictions served by the same assets.

We require inputs such as coal, natural gas, uranium and water to cool our facilities. Lack of availability of these resources could jeopardize long-term operations of our facilities or make them uneconomic to operate.

Our utility operations are highly dependent on suppliers to deliver components in accordance with short and long-term project schedules.

Our products contain components that are globally sourced from suppliers who, in turn, source components from their suppliers. A shortage of key components in which an alternative supplier is not identified could significantly impact operations and project plans for NSP-Minnesota and our customers. Such impacts could include timing of projects, including potential for project cancellation. Failure to adhere to project budgets and timelines adversely impacts our results of operations, financial condition or cash flows.

We are subject to commodity risks and other risks associated with energy markets and energy production.

A significant increase in fuel costs could cause a decline in customer demand, adverse regulatory outcomes and an increase in bad debt expense which may have a material impact on our results of operations. Despite existing fuel cost recovery mechanisms, higher fuel costs could significantly impact our results of operations if costs are not recovered. Delays in the timing of the collection of fuel cost recoveries could impact our cash flows and liquidity.

A significant disruption in supply could cause us to seek alternative supply services at potentially higher costs. Additionally, supply shortages may not be fully resolved, which negatively impacts our ability to provide services to our customers. Failure to provide service due to disruptions may also result in fines, penalties or cost disallowances through the regulatory process. Also, significantly higher energy or fuel costs relative to sales commitments negatively impacts our cash flows and results of operations.

We also engage in wholesale sales and purchases of electric capacity, energy and energy-related products as well as natural gas. In many markets, emission allowances and/or RECs are also needed to comply with various statutes and commission rulings. As a result, we are subject to market supply and commodity price risk.

Commodity price changes can affect the value of our commodity trading derivatives. We mark certain derivatives to estimated fair market value on a daily basis. Settlements can vary significantly from estimated fair values recorded and significant changes from the assumptions underlying our fair value estimates could cause earnings variability. The management of risks associated with hedging and trading is based, in part, on programs and procedures which utilize historical prices and trends.

Public perception often does not distinguish between pass through commodity costs and base rates. High commodity prices that are being passed through to customer bills could impact our ability to recover costs for other improvements and operations.

Due to the uncertainty involved in price movements and potential deviation from historical pricing, NSP-Minnesota is unable to fully assure that its risk management programs and procedures would be effective to protect against all significant adverse market deviations. In addition, NSP-Minnesota cannot fully assure that its controls will be effective against all potential risks. If such programs and procedures are not effective, NSP-Minnesota's results of operations, financial condition or cash flows could be materially impacted.

Failure to attract and retain a qualified workforce could have an adverse effect on operations.

The competition for talent has become increasingly prevalent, and we have experienced increased employee turnover due to the condition of the labor market. In addition, specialized knowledge and skills are required for many of our positions, which may pose additional difficulty for us as we work to recruit, retain and motivate employees in this climate. Failure to hire and adequately train replacement employees, including the transfer of significant knowledge and expertise to new employees or future availability and cost of contract labor may adversely affect the ability to manage and operate our business. Inability to attract and retain these employees adversely impacts our results of operations, financial condition or cash flows.

Our operations use third-party contractors in addition to employees to perform periodic and ongoing work.

We rely on third-party contractors to perform operations, maintenance and construction work. Our contractual arrangements with these contractors typically include performance and safety standards, progress payments, insurance requirements and security for performance. Poor vendor performance or contractor unavailability could impact ongoing operations, restoration operations, regulatory recovery, our reputation and could introduce financial risk or risks of fines.

Our employees, directors, third-party contractors, or suppliers may violate or be perceived to violate our Codes of Conduct, which could have an adverse effect on our reputation.

We are exposed to risk of employee or third-party contractor fraud or misconduct. All employees and members of the Board of Directors are subject to comply with our Code of Conduct and are required to participate in annual training. Additionally, suppliers are subject to comply with our Supplier Code of Conduct. NSP-Minnesota does not tolerate discrimination, violations of our Code of Conduct or other unacceptable behaviors. However, it is not always possible to identify and deter misconduct by employees and other third-parties, which may result in governmental investigations, other actions or lawsuits. If such actions are taken against us we may suffer loss of reputation and such actions could have a material effect on our financial condition, results of operations and cash flows.

We are subject to the risks of nuclear generation.

NSP-Minnesota has two nuclear generation plants, PI and Monticello. Risks of nuclear generation include:

- Hazards associated with the use of radioactive material in energy production, including management, handling, storage and disposal.
- Limitations on insurance available to cover losses that may arise in connection with nuclear operations, as well as obligations to contribute to an insurance pool in the event of damages at a covered U.S. reactor.
- Technological and financial uncertainties related to the costs of decommissioning nuclear plants may cause our funding obligations to change.

The NRC has authority to impose licensing and safety-related requirements for the operation of nuclear generation facilities, including the ability to impose fines and/or shut down a unit until compliance is achieved. NRC safety requirements could necessitate substantial capital expenditures or an increase in operating expenses. In addition, the INPO reviews our nuclear operations. Compliance with the INPO's recommendations could result in substantial capital expenditures or a substantial increase in operating expenses.

If a nuclear incident did occur, it could have a material impact on our results of operations, financial condition or cash flows. Furthermore, non-compliance or the occurrence of a serious incident at other nuclear facilities could result in increased industry regulation, which may increase our compliance costs.

We are a wholly owned subsidiary of Xcel Energy Inc. Xcel Energy Inc. can exercise substantial control over our dividend policy and business and operations and may exercise that control in a manner that may be perceived to be adverse to our interests.

All of the members of our Board of Directors, as well as many of our executive officers, are officers of Xcel Energy Inc. Our Board of Directors makes determinations with respect to a number of significant corporate events, including the payment of our dividends.

We have historically paid quarterly dividends to Xcel Energy Inc. If Xcel Energy Inc.'s cash requirements increase, our Board of Directors could decide to increase the dividends we pay to Xcel Energy Inc. to help support Xcel Energy Inc.'s cash needs. This could adversely affect our liquidity. The most restrictive dividend limitation for NSP-Minnesota is imposed by our state regulatory commissions. State regulatory commissions indirectly limit the amount of dividends NSP-Minnesota can pay to Xcel Energy Inc., by requiring a minimum equity-to-total capitalization ratio.

See Note 5 to the consolidated financial statements for further information.

Financial Risks

Our profitability depends on our ability to recover costs and changes in regulation may impair our ability to recover costs from our customers.

We are subject to comprehensive regulation by federal and state utility regulatory agencies, including siting and construction of facilities, customer service and the rates that we can charge customers.

The profitability of our operations is dependent on our ability to recover the costs of providing energy and utility services and earn a return on capital investment. Our rates are generally regulated and are based on an analysis of our costs incurred in a test year. We are subject to both future and historical test years depending upon the regulatory jurisdiction. Thus, the rates we are allowed to charge may or may not match our costs at any given time. Rate regulation is premised on providing an opportunity to earn a reasonable rate of return on invested capital.

There can also be no assurance that our regulatory commissions will judge all our costs to be prudent, which could result in disallowances, or that the regulatory process will always result in rates that will produce full recovery.

Overall, management believes prudently incurred costs are recoverable given the existing regulatory framework. However, there may be changes in the regulatory environment that could impair our ability to recover costs historically collected from customers, or we could exceed caps on capital costs required by commissions and result in less than full recovery.

Changes in the long-term cost-effectiveness or to the operating conditions of our assets may result in early retirements of utility facilities. While regulation typically provides cost recovery relief for these types of changes, there is no assurance that regulators would allow full recovery of all remaining costs.

Higher than expected inflation or tariffs may increase costs of construction and operations. Also, rising fuel costs could increase the risk that we will not be able to fully recover our fuel costs from our customers.

Adverse regulatory rulings (including changes in recovery mechanisms) or the imposition of additional regulations could have an adverse impact on our results of operations and materially affect our ability to meet our financial obligations, including debt payments and the payment of dividends on common stock.

Any reductions in our credit ratings could increase our financing costs and the cost of maintaining certain contractual relationships.

We cannot be assured that our current credit ratings will remain in effect, or that a rating will not be lowered or withdrawn by a rating agency. Significant events including disallowance of costs, use of historic test years, elimination of riders or interim rates, increasing depreciation lives, lower returns on equity, changes to equity ratios and impacts of tax policy may impact our cash flows and credit metrics, potentially resulting in a change in our credit ratings. In addition, our credit ratings may change as a result of the differing methodologies or change in the methodologies used by the various rating agencies.

Any credit ratings downgrade could lead to higher borrowing costs or lower proceeds from equity issuances. It could also impact our ability to access capital markets. Also, we may enter into contracts that require posting of collateral or settlement if credit ratings fall below investment grade.

We are subject to capital market and interest rate risks.

Utility operations require significant capital investment. As a result, we frequently need to access capital markets. Any disruption in capital markets could have a material impact on our ability to fund our operations. Capital market disruption and financial market distress could prevent us from issuing commercial paper, issuing new securities or cause us to issue securities with unfavorable terms and conditions, such as higher interest rates or lower proceeds from equity issuances. Higher interest rates on short-term borrowings with variable interest rates could also have an adverse effect on our operating results.

The performance of capital markets impacts the value of assets held in trusts to satisfy future obligations to decommission our nuclear plants and satisfy our defined benefit pension and postretirement benefit plan obligations. These assets are subject to market fluctuations and yield uncertain returns, which may fall below expected returns. A decline in the market value of these assets may increase funding requirements. Additionally, the fair value of the debt securities held in the nuclear decommissioning and/or pension trusts may be impacted by changes in interest rates.

We are subject to credit risks.

Credit risk includes the risk that our customers will not pay their bills, which may lead to a reduction in our liquidity and an increase in bad debt expense. Credit risk is comprised of numerous factors including the price of products and services provided, the economy and unemployment rates.

Credit risk also includes the risk that counterparties that owe us money or product will become insolvent and may breach their obligations. Should the counterparties fail to perform, we may be forced to enter into alternative arrangements. In that event, our financial results could be adversely affected and incur losses.

We may have direct credit exposure in our short-term wholesale and commodity trading activity to financial institutions trading for their own accounts or issuing collateral support on behalf of other counterparties. We may also have some indirect credit exposure due to participation in organized markets, (e.g., MISO, Electric Reliability Council of Texas and California ISO), in which any credit losses are socialized to all market participants.

We have additional indirect credit exposure to financial institutions from letters of credit provided as security by power suppliers under various purchased power contracts. If any of the credit ratings of the letter of credit issuers were to drop below investment grade, the supplier would need to replace that security with an acceptable substitute. If the security were not replaced, the party could be in default under the contract.

As we are a subsidiary of Xcel Energy Inc., we may be negatively affected by events impacting the credit or liquidity of Xcel Energy Inc. and its affiliates.

If either S&P or Moody's were to downgrade Xcel Energy Inc.'s debt securities below investment grade, it would increase Xcel Energy Inc.'s cost of capital and restrict its access to the capital markets. This could limit Xcel Energy Inc.'s ability to contribute equity or make loans to us or may cause Xcel Energy Inc. to seek additional or accelerated funding from us in the form of dividends. If such event were to occur, we may need to seek alternative sources of funds to meet our cash needs.

As of Dec. 31, 2022, Xcel Energy Inc. and its utility subsidiaries had approximately $22.8 billion of long-term debt and $2.0 billion of short-term debt and current maturities. Xcel Energy Inc. provides various guarantees and bond indemnities supporting some of its subsidiaries by guaranteeing the payment or performance by these subsidiaries for specified agreements or transactions.

Xcel Energy also has other contingent liabilities resulting from various tax disputes and other matters. Xcel Energy Inc.'s exposure under the guarantees is based upon the net liability of the relevant subsidiary under the specified agreements or transactions. The majority of Xcel Energy Inc.'s guarantees limit its exposure to a maximum amount that is stated in the guarantees.

As of Dec. 31, 2022, Xcel Energy had the following guarantees outstanding:

- $1 million maximum stated amount and immaterial exposure.
- $61 million for performance and payment of surety bonds for the benefit of itself and its subsidiaries, with total exposure that cannot be estimated at this time.
- $98 million for performance and payment of a capital services contract for solar generating equipment, with immaterial exposure.

If Xcel Energy Inc. were to become obligated to make payments under these guarantees and bond indemnities or become obligated to fund other contingent liabilities, it could limit Xcel Energy Inc.'s ability to contribute equity or make loans to us, or may cause Xcel Energy Inc. to seek additional or accelerated funding from us in the form of dividends. If such event were to occur, we may need to seek alternative sources of funds to meet our cash needs.

Increasing costs of our defined benefit retirement plans and employee benefits may adversely affect our results of operations, financial condition or cash flows.

We have defined benefit pension and postretirement plans that cover most of our employees. Assumptions related to future costs, return on investments, interest rates and other actuarial assumptions have a significant impact on our funding requirements of these plans. Estimates and assumptions may change. In addition, the Pension Protection Act sets the minimum funding requirements for defined benefit pension plans. Therefore, our funding requirements and contributions may change in the future. Also, the payout of a significant percentage of pension plan liabilities in a single year due to high numbers of retirements or employees leaving NSP-Minnesota could trigger settlement accounting and could require NSP-Minnesota to recognize incremental pension expense related to unrecognized plan losses in the year liabilities are paid. Changes in industry standards utilized in key assumptions (e.g., mortality tables) could have a significant impact on future obligations and benefit costs.

Increasing costs associated with health care plans may adversely affect our results of operations.

Increasing levels of large individual health care claims and overall health care claims could have an adverse impact on our results of operations, financial condition or cash flows. Health care legislation could also significantly impact our benefit programs and costs.

Federal tax law may significantly impact our business.

NSP-Minnesota collects estimated federal, state and local tax payments through their regulated rates. Changes to federal tax law may benefit or adversely affect our earnings and customer costs. Tax depreciable lives and the value/availability of various tax credits or the timeliness of their utilization may impact the economics or selection of resources. If tax rates are increased, there could be timing delays before regulated rates provide for recovery of such tax increases in revenues. In addition, certain IRS tax policies such as tax normalization may impact our ability to economically deliver certain types of resources relative to market prices.

Macroeconomic Risks

Economic conditions impact our business.

Our operations are affected by economic conditions, which correlates to customers/sales growth (decline). Economic conditions may be impacted by recessionary factors, rising interest rates and insufficient financial sector liquidity leading to potential increased unemployment, which may impact customers' ability to pay their bills which could lead to additional bad debt expense.

Additionally, NSP-Minnesota faces competitive factors, which could have an adverse impact on our financial condition, results of operations and cash flows. Further, worldwide economic activity impacts the demand for basic commodities necessary for utility infrastructure, which may inhibit our ability to acquire sufficient supplies. We operate in a capital intensive industry and federal trade policy could significantly impact the cost of materials we use. There may be delays before these additional material costs can be recovered in rates.

We face risks related to health epidemics and other outbreaks, which may have a material effect on our financial condition, results of operations and cash flows.

Health epidemics continue to impact countries, communities, supply chains and markets. Uncertainty continues to exist regarding epidemics; the duration and magnitude of business restrictions including shutdowns (domestically and globally); the potential impact on the workforce including shortages of employees and third-party contractors due to quarantine policies, vaccination requirements or government restrictions; impacts on the transportation of goods, and the generalized impact on the economy.

We cannot ultimately predict whether an epidemic will have a material impact on our future liquidity, financial condition or results of operations. Nor can we predict the impact on the health of our employees, our supply chain or our ability to recover higher costs associated with managing an outbreak.

Operations could be impacted by war, terrorism, or other events.

Our generation plants, fuel storage facilities, transmission and distribution facilities and information and control systems may be targets of terrorist activities. Any disruption could impact operations or result in a decrease in revenues and additional costs to repair and insure our assets. These disruptions could have a material impact on our financial condition, results of operations or cash flows. The potential for terrorism has subjected our operations to increased risks and could have a material effect on our business. We have incurred increased costs for security and capital expenditures in response to these risks. The insurance industry has also been affected by these events and the availability of insurance may decrease. In addition, insurance may have higher deductibles, higher premiums and more restrictive policy terms.

A disruption of the regional electric transmission grid, interstate natural gas pipeline infrastructure or other fuel sources, could negatively impact our business, brand and reputation. Because our facilities are part of an interconnected system, we face the risk of possible loss of business due to a disruption caused by the actions of a neighboring utility.

We also face the risks of possible loss of business due to significant events such as severe storms, temperature extremes, wildfires, widespread pandemic, generator or transmission facility outage, pipeline rupture, railroad disruption, operator error, sudden and significant increase or decrease in wind generation or a workforce disruption.

In addition, major catastrophic events throughout the world may disrupt our business. While we have business continuity plans in place, our ability to recover may be prolonged due to the type and extent of the event. NSP-Minnesota participates in a global supply chain, which includes materials and components that are globally sourced. A prolonged disruption could result in the delay of equipment and materials that may impact our ability to connect, restore and reliably serve our customers.

A major disruption could result in a significant decrease in revenues, additional costs to repair assets, and an adverse impact on the cost and availability of insurance, which could have a material impact on our results of operations, financial condition or cash flows.

A cyber incident or security breach could have a material effect on our business.

We operate in an industry that requires the continued operation of sophisticated information technology, control systems and network infrastructure. In addition, we use our systems and infrastructure to create, collect, use, disclose, store, dispose of and otherwise process sensitive information, including Company data, customer energy usage data, and personal information regarding customers, employees and their dependents, contractors and other individuals.

Our generation, transmission, distribution and fuel storage facilities, information technology systems and other infrastructure or physical assets, as well as information processed in our systems (e.g., information regarding our customers, employees, operations, infrastructure and assets) could be affected by cyber security incidents, including those caused by human error.

The utility industry has been the target of several attacks on operational systems and has seen an increased volume and sophistication of cyber security incidents from international activist organizations, other countries and individuals. We expect to continue to experience attempts to compromise our information technology and control systems, network infrastructure and other assets. To date, no cybersecurity incident or attack has had a material impact on our business or results of operations.

Cyber security incidents could harm our businesses by limiting our generating, transmitting and distributing capabilities, delaying our development and construction of new facilities or capital improvement projects to existing facilities, disrupting our customer operations or causing the release of customer information, all of which would likely receive state and federal regulatory scrutiny and could expose us to liability.

Our generation, transmission systems and natural gas pipelines are part of an interconnected system. Therefore, a disruption caused by the impact of a cyber security incident on the regional electric transmission grid, natural gas pipeline infrastructure or other fuel sources of our third-party service providers' operations, could also negatively impact our business.

Our supply chain for procurement of digital equipment and services may expose software or hardware to these risks and could result in a breach or significant costs of remediation. We are unable to quantify the potential impact of cyber security threats or subsequent related actions. Cyber security incidents and regulatory action could result in a material decrease in revenues and may cause significant additional costs (e.g., penalties, third-party claims, repairs, insurance or compliance) and potentially disrupt our supply and markets for natural gas, oil and other fuels.

We maintain security measures to protect our information technology and control systems, network infrastructure and other assets. However, these assets and the information they process may be vulnerable to cyber security incidents, including asset failure or unauthorized access to assets or information. A failure or breach of our technology systems or those of our third-party service providers could disrupt critical business functions and may negatively impact our business, our brand, and our reputation. The cyber security threat is dynamic and evolves continually, and our efforts to prioritize network protection may not be effective given the constant changes to threat vulnerability.

While the Company maintains insurance relating to cybersecurity events, such insurance is subject to a number of exclusions and may be insufficient to offset any losses, costs or damages experienced. Also, the market for cybersecurity insurance is relatively new and coverage available for cybersecurity events is evolving as the industry matures.

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Our operating results may fluctuate on a seasonal and quarterly basis and can be adversely affected by milder weather.

Our electric and natural gas utility businesses are seasonal and weather patterns can have a material impact on our operating performance. Demand for electricity is often greater in the summer and winter months associated with cooling and heating. Because natural gas is heavily used for residential and commercial heating, the demand depends heavily upon weather patterns. A significant amount of natural gas revenues are recognized in the first and fourth quarters related to the heating season. Accordingly, our operations have historically generated less revenues and income when weather conditions are milder in the winter and cooler in the summer. Unusually mild winters and summers could have an adverse effect on our financial condition, results of operations or cash flows.

Public Policy Risks

Increased risks of regulatory penalties could negatively impact our business.

The Energy Act increased civil penalty authority for violation of FERC statutes, rules and orders. FERC can impose penalties of up to $1.5 million per violation per day, particularly as it relates to energy trading activities for both electricity and natural gas. In addition, NERC electric reliability standards and critical infrastructure protection requirements are mandatory and subject to potential financial penalties. Also, the PHMSA, Occupational Safety and Health Administration and other federal agencies have the authority to assess penalties.

In the event of serious incidents, these agencies may pursue penalties. In addition, certain states have the authority to impose substantial penalties. If a serious reliability, cyber or safety incident did occur, it could have a material effect on our results of operations, financial condition or cash flows.

The continued use of natural gas for both power generation and gas distribution have increasingly become a public policy advocacy target. These efforts may result in a limitation of natural gas as an energy source for both power generation and heating, which could impact our ability to reliably and affordably serve our customers.

In recent years, there have been various local and state agency proposals within and outside our service territories that would attempt to restrict the use and availability of natural gas. If such policies were to prevail, we may be forced to make new resource investment decisions which could potentially result in stranded costs if we are not able to fully recover costs and investments and impact the overall reliability of our service.

Environmental Policy Risks

We may be subject to legislative and regulatory responses to climate change, with which compliance could be difficult and costly.

Legislative and regulatory responses related to climate change may create financial risk as our facilities may be subject to additional regulation at either the state or federal level in the future. International agreements could additionally lead to future federal or state regulations.

In 2015, the United Nations Framework Convention on Climate Change reached consensus among 190 nations on an agreement (the Paris Agreement) that establishes a framework for GHG mitigation actions by all countries, with a goal of holding the increase in global average temperature to below 2º Celsius above pre-industrial levels and an aspiration to limit the increase to 1.5º Celsius. International commitments and agreements could result in future additional GHG reductions in the United States. In addition, in 2023 the EPA intends to publish draft regulations for GHG emissions from the power sector consistent with the agency's Clean Air Act authorities.

Many states and localities continue to pursue their own climate policies. The steps NSP-Minnesota has taken to date to reduce GHG emissions, including energy efficiency measures, adding renewable generation and retiring or converting coal plants to natural gas, occurred under state-endorsed resource plans, renewable energy standards and other state policies.

We may be subject to climate change lawsuits. An adverse outcome could require substantial capital expenditures and possibly require payment of substantial penalties or damages. Defense costs associated with such litigation can also be significant and could affect results of operations, financial condition or cash flows if such costs are not recovered through regulated rates.

If our regulators do not allow us to recover all or a part of the cost of capital investment or the O&M costs incurred to comply with the mandates, it could have a material effect on our results of operations, financial condition or cash flows.

We are subject to environmental laws and regulations, with which compliance could be difficult and costly.

We are subject to environmental laws and regulations that affect many aspects of our operations, including air emissions, water quality, wastewater discharges and the generation, transport and disposal of solid wastes and hazardous substances. Laws and regulations require us to obtain permits, licenses, and approvals and to comply with a variety of environmental requirements.

Environmental laws and regulations can also require us to restrict or limit the output of facilities or the use of certain fuels, shift generation to lower-emitting facilities, install pollution control equipment, clean up spills and other contamination and correct environmental hazards. Failure to meet requirements of environmental mandates may result in fines or penalties. We may be required to pay all or a portion of the cost to remediate sites where our past activities, or the activities of other parties, caused environmental contamination.

Changes in environmental policies and regulations or regulatory decisions may result in early retirements of our generation facilities. While regulation typically provides relief for these types of changes, there is no assurance that regulators would allow full recovery of all remaining costs.

We are subject to mandates to provide customers with clean energy, renewable energy and energy conservation offerings. It could have a material effect on our results of operations, financial condition or cash flows if our regulators do not allow us to recover the cost of capital investment or O&M costs incurred to comply with the requirements.

In addition, existing environmental laws or regulations may be revised and new laws or regulations may be adopted. We may also incur additional unanticipated obligations or liabilities under existing environmental laws and regulations.

We are subject to physical and financial risks associated with climate change and other weather, natural disaster and resource depletion impacts.

Climate change can create physical and financial risk. Physical risks include changes in weather conditions and extreme weather events.

Our customers' energy needs vary with weather. To the extent weather conditions are affected by climate change, customers' energy use could increase or decrease. Increased energy use due to weather changes may require us to invest in generating assets, transmission and infrastructure. Decreased energy use due to weather changes may result in decreased revenues.

Climate change may impact the economy, which could impact our sales and revenues. The price of energy has an impact on the economic health of our communities. The cost of additional regulatory requirements, such as regulation of GHG, could impact the availability of goods and prices charged by our suppliers which would normally be borne by consumers through higher prices for energy and purchased goods. To the extent financial markets view climate change and emissions of GHGs as a financial risk, this could negatively affect our ability to access capital markets or cause us to receive less than ideal terms and conditions.

We establish strategies and expectations related to climate change and other environmental matters. Our ability to achieve any such strategies or expectations is subject to numerous factors and conditions, many of which are outside of our control. Examples of such factors include, but are not limited to, evolving legal, regulatory, and other standards, processes, and assumptions, the pace of scientific and technological developments, increased costs, the availability of requisite financing, and changes in carbon markets. Failures or delays (whether actual or perceived) in achieving our strategies or expectations related to climate change and other environmental matters could adversely affect our business, operations, and reputation, and increase risk of litigation.

Severe weather impacts our service territories, primarily when thunderstorms, flooding, tornadoes, wildfires and snow or ice storms or extreme temperatures (high heating/cooling days) occur. Extreme weather conditions in general require system backup and can contribute to increased system stress, including service interruptions. Extreme weather conditions creating high energy demand may raise electricity prices, increasing the cost of energy we provide to our customers.

To the extent the frequency of extreme weather events increases, this could increase our cost of providing service and result in more frequent service interruptions. Periods of extreme temperatures could also impact our ability to meet demand.

More frequent and severe drought conditions, extreme swings in amount and timing of precipitation, changes in vegetation, unseasonably warm temperatures, very low humidity, stronger winds and other factors have increased the duration of the wildfire season and the potential impact of an event. Also, the expansion of the wildland urban interface increases the wildfire risk to surrounding communities and NSP-Minnesota's electric and natural gas infrastructure.

Other potential risks associated with wildfires include the inability to secure sufficient insurance coverage, or increased costs of insurance, regulatory recovery risk, and the potential for a credit downgrade and subsequent additional costs to access capital markets.

While we carry liability insurance, given an extreme event, if NSP-Minnesota was found to be liable for wildfire damages, amounts that potentially exceed our coverage could negatively impact our results of operations, financial condition or cash flows. Drought or water depletion could adversely impact our ability to provide electricity to customers, cause early retirement of power plants and increase the cost for energy. Adverse events may result in increased insurance costs and/or decreased insurance availability We may not recover all costs related to mitigating these physical and financial risks.

ITEM 1B — UNRESOLVED STAFF COMMENTS

None.

ITEM 2 — PROPERTIES

Virtually all of the utility plant property of NSP-Minnesota is subject to the lien of its first mortgage bond indenture.

Station, Location and Unit at Dec. 31, 2022	Fuel	Installed	MW [(a)]
Steam:			
A.S. King-Bayport, MN, 1 Unit	Coal	1968	511
Sherco-Becker, MN			
Unit 1	Coal	1976	680
Unit 2	Coal	1977	682
Unit 3	Coal	1987	517 [(b)]
Monticello, MN, 1 Unit	Nuclear	1971	617
PI-Welch, MN			
Unit 1	Nuclear	1973	521
Unit 2	Nuclear	1974	519
Various locations, 4 Units	Wood/Refuse	Various	36 [(c)]
Combustion Turbine:			
Angus Anson-Sioux Falls, SD, 3 Units	Natural Gas	1994 - 2005	327
Black Dog-Burnsville, MN, 3 Units	Natural Gas	1987 - 2018	494
Blue Lake-Shakopee, MN, 6 Units	Natural Gas	1974 - 2005	447
High Bridge-St. Paul, MN, 3 Units	Natural Gas	2008	530
Inver Hills-Inver Grove Heights, MN, 6 Units	Natural Gas	1972	252
Riverside-Minneapolis, MN, 3 Units	Natural Gas	2009	454
Various locations, 7 Units	Natural Gas	Various	10
Wind:			
Blazing Star 1-Lincoln County, MN, 100 Units	Wind	2020	200 [(d)]
Blazing Star 2-Lincoln County, MN, 100 Units	Wind	2021	200 [(d)]
Border-Rolette County, ND, 75 Units	Wind	2015	148 [(d)]
Community Wind North-Lincoln County, MN, 12 Units	Wind	2020	26 [(d)]
Courtenay Wind-Stutsman County, ND, 100 Units	Wind	2016	190 [(d)]
Crowned Ridge 2-Grant County, SD, 88 Units	Wind	2020	192 [(d)]
Dakota Range, SD, 72 Units	Wind	2022	298 [(d)]
Foxtail-Dickey County, ND, 75 Units	Wind	2019	150 [(d)]
Freeborn-Freeborn County, MN, 100 Units	Wind	2021	200 [(d)]
Grand Meadow-Mower County, MN, 67 Units	Wind	2008	99 [(d)]
Jeffers-Cottonwood County, MN, 20 Units	Wind	2020	43 [(d)]
Lake Benton-Pipestone County, MN, 44 Units	Wind	2019	99 [(d)]
Mower-Mower County, MN, 43 Units	Wind	2021	91 [(d)]
Nobles-Nobles County, MN, 133 Units [(e)]	Wind	2010	200 [(d)]
Pleasant Valley-Mower County, MN, 100 Units	Wind	2015	196 [(d)]
Rock Aetna - Murray County, MN, 8 Units	Wind	2022	20 [(d)]
		Total	8,949

(a) Summer 2022 net dependable capacity.
(b) Based on NSP-Minnesota's ownership of 59%.
(c) Refuse-derived fuel is made from municipal solid waste.
(d) Capacity is attainable only when wind conditions are sufficiently available.
(e) Repowered in 2022.

Electric utility overhead and underground transmission and distribution lines (measured in conductor miles) at Dec. 31, 2022:

Conductor Miles	
Transmission	
500 KV	2,915
345 KV	12,183
230 KV	2,300
161 KV	626
115 KV	8,033
Less than 115 KV	6,537
Total Transmission	32,594
Distribution	
Less than 115 KV	82,024
Total	**114,618**

NSP-Minnesota had 352 electric utility transmission and distribution substations at Dec. 31, 2022.

Natural gas utility mains at Dec. 31, 2022:

Miles	
Transmission	78
Distribution	10,902

ITEM 3 — LEGAL PROCEEDINGS

NSP-Minnesota is involved in various litigation matters in the ordinary course of business. The assessment of whether a loss is probable or is a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Management maintains accruals for losses probable of being incurred and subject to reasonable estimation.

Management is sometimes unable to estimate an amount or range of a reasonably possible loss in certain situations, including but not limited to, when (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss.

For current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, would have a material effect on NSP-Minnesota's consolidated financial statements. Legal fees are generally expensed as incurred.

See Note 10 to the consolidated financial statements, Item 1 and Item 7 for further information.

ITEM 4 — MINE SAFETY DISCLOSURES

None.

PART II

ITEM 5 — MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

NSP-Minnesota is a wholly owned subsidiary of Xcel Energy Inc. and there is no market for its common equity securities.

The dividends declared during 2022 and 2021 were as follows:

(Millions of Dollars)	2022	2021
First quarter	$ 167	$ 109
Second quarter	114	107
Third quarter	182	109
Fourth quarter	123	96

ITEM 6 — [RESERVED]

ITEM 7 — MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Discussion of financial condition and liquidity for NSP-Minnesota is omitted per conditions set forth in General Instructions I(1)(a) and (b) of Form 10-K for wholly owned subsidiaries. It is replaced with management's narrative analysis of the results of operations set forth in General Instruction I(2)(a) of Form 10-K for wholly owned subsidiaries (reduced disclosure format).

Non-GAAP Financial Measures

The following discussion includes financial information prepared in accordance with GAAP, as well as certain non-GAAP financial measures such as ongoing earnings. Generally, a non-GAAP financial measure is a measure of a company's financial performance, financial position or cash flows that are adjusted from measures calculated and presented in accordance with GAAP.

NSP-Minnesota's management uses non-GAAP measures for financial planning and analysis, for reporting of results to the Board of Directors, in determining performance-based compensation and communicating its earnings outlook to analysts and investors. Non-GAAP financial measures are intended to supplement investors' understanding of our performance and should not be considered alternatives for financial measures presented in accordance with GAAP. These measures are discussed in more detail below and may not be comparable to other companies' similarly titled non-GAAP financial measures.

Earnings Adjusted for Certain Items (Ongoing Earnings)

Ongoing earnings reflect adjustments to GAAP earnings (net income) for certain items.

We use these non-GAAP financial measures to evaluate and provide details of NSP-Minnesota's core earnings and underlying performance. We believe these measurements are useful to investors to evaluate the actual and projected financial performance and contribution of NSP-Minnesota. For the years ended Dec. 31, 2022 and 2021, there were no such adjustments to GAAP earnings and therefore GAAP earnings equal ongoing earnings.

Results of Operations

2022 Comparison with 2021

NSP-Minnesota's net income was approximately $675 million for 2022, compared with approximately $606 million for 2021. The increase in earnings is driven primarily by regulatory rate outcomes, partially offset by additional depreciation and O&M expenses.

Electric Margin

Electric margin is presented as electric revenues less electric fuel and purchased power expenses. Expenses incurred for electric fuel and purchased power are generally recovered through various regulatory recovery mechanisms. As a result, changes in these expenses are generally offset in operating revenues.

Electric revenues and fuel and purchased power expenses are impacted by fluctuations in the price of natural gas, coal and uranium. However, these price fluctuations generally have minimal impact on earnings impact due to fuel recovery mechanisms. In addition, electric customers receive a credit for PTCs generated, which reduce electric revenue and income taxes.

Electric Revenues, Fuel and Purchased Power and Electric Margin

(Millions of Dollars)	2022	2021
Electric revenues	$ 5,617	$ 5,094
Electric fuel and purchased power	(2,416)	(2,042)
Electric margin	$ 3,201	$ 3,052

Changes in Electric Margin

(Millions of Dollars)	2022 vs. 2021
Regulatory rate outcome (Minnesota)	$ 183
Non-fuel riders	36
Wholesale transmission (net)	28
PTCs flowed back to customers (offset by lower ETR)	(109)
Other (net)	11
Total increase	$ 149

Natural Gas Margin

Natural gas margin is presented as natural gas revenues less the cost of natural gas sold and transported. Expenses incurred for the cost of natural gas sold are generally recovered through various regulatory recovery mechanisms. As a result, changes in these expenses are generally offset in operating revenues.

Natural gas expense varies with changing sales and the cost of natural gas. However, fluctuations in the cost of natural gas generally have minimal earnings impact due to cost recovery mechanisms.

Natural Gas Revenues, Cost of Natural Gas Sold and Transported and Natural Gas Margin

(Millions of Dollars)	2022	2021
Natural gas revenues	$ 1,022	$ 623
Cost of natural gas sold and transported	(741)	(385)
Natural gas margin	$ 281	$ 238

Changes in Natural Gas Margin

(Millions of Dollars)	2022 vs. 2021
Regulatory rate outcomes (Minnesota, North Dakota)	$ 27
Estimated impact of weather	12
Conservation revenue (offset in expenses)	9
Infrastructure and integrity riders	7
Winter Storm Uri disallowance	(16)
Other (net)	4
Total increase	$ 43

Non-Fuel Operating Expenses and Other Items

O&M Expenses — O&M expenses increased $38 million year-to-date. The increase was primarily due to inflation and impacts of supply chain constraints; operational activities (vegetation management, repairs/maintenance and storms); costs for technology and customer programs; insurance-related costs; interchange; and other.

Depreciation and Amortization — Depreciation and amortization expense increased $88 million for 2022. The increase was primarily driven by capital investment, including several wind farms going into service in 2021 and 2022.

Interest Charges — Interest charges increased $20 million year-to-date. The increase was largely due to higher debt levels to fund capital investments and higher interest rates.

Income Taxes — Income tax benefit increased $64 million for 2022. The increase was primarily driven by increased wind PTCs due to several new wind farms going into service and greater production at existing wind farms. Wind PTCs are credited to customers (recorded as a reduction to revenue) and do not have a material impact on net income.

Public Utility Regulation

The FERC and various state and local regulatory commissions regulate NSP-Minnesota. NSP-Minnesota is subject to rate regulation by state utility regulatory agencies, which have jurisdiction with respect to the rates of electric and natural gas distribution companies in Minnesota, North Dakota and South Dakota.

Rates are designed to recover plant investment, operating costs and an allowed return on investment. NSP-Minnesota requests changes in utility rates through commission filings. Changes in operating costs can affect NSP-Minnesota's financial results, depending on the timing of rate cases and implementation of final rates. Other factors affecting rate filings are new investments, sales, conservation and demand side management efforts, and the cost of capital.

In addition, the regulatory commissions authorize the ROE, capital structure and depreciation rates in rate proceedings. Decisions by these regulators can significantly impact NSP-Minnesota's results of operations and credit quality.

See Rate Matters within Note 12 to the consolidated financial statements for further information.

Summary of Regulatory Agencies / RTO and Areas of Jurisdiction

Regulatory Body / RTO	Additional Information
MPUC	Retail rates, services, security issuances, property transfers, mergers, disposition of assets, affiliate transactions, and other aspects of electric and natural gas operations. Reviews and approves Integrated Resource Plans for meeting future energy needs. Certifies the need and siting for generating plants greater than 50 MW and transmission lines greater than 100 KV in Minnesota. Reviews and approves natural gas supply plans.
NDPSC	Retail rates, services and other aspects of electric and natural gas operations. Reviews and approves Integrated Resource Plans for meeting future energy needs. Regulatory authority over generation and transmission facilities, along with the siting and routing of new generation and transmission facilities in North Dakota. Pipeline safety compliance.
SDPUC	Retail rates, services and other aspects of electric operations. Regulatory authority over generation and transmission facilities, along with the siting and routing of new generation and transmission facilities in South Dakota. Pipeline safety compliance.
FERC	Wholesale electric operations, hydroelectric licensing, accounting practices, wholesale sales for resale, transmission of electricity in interstate commerce, compliance with NERC electric reliability standards, asset transfers and mergers, and natural gas transactions in interstate commerce.
MISO	NSP-Minnesota is a transmission owning member of the MISO RTO and operates within the MISO RTO and wholesale markets. NSP-Minnesota makes wholesale sales in other RTO markets at market-based rates. NSP-Minnesota and NSP-Wisconsin also make wholesale electric sales at market-based prices to customers outside of their balancing authority as jointly authorized by the FERC.
DOT	Pipeline safety compliance.
Minnesota Office of Pipeline Safety	Pipeline safety compliance.

Recovery Mechanisms

Mechanism	Additional Information
CIP Rider [(a)]	Recovers costs of conservation and DSM programs in Minnesota.
Environmental Improvement Rider	Recovers costs of environmental improvement projects in Minnesota.
Renewable Development Fund	Allocates money collected from customers to support research and development of emerging renewable energy projects and technologies in Minnesota.
RES	Recovers cost of renewable generation in Minnesota.
Renewable Energy Rider	Recovers cost of renewable generation in North Dakota.
Transmission Cost Recovery	Recovers costs for investments in Minnesota, North Dakota, and South Dakota for electric transmission and distribution grid modernization.
Infrastructure Rider	Recovers costs for investments in generation in South Dakota.
Fuel Clause Adjustment	Recovers prudently incurred costs of fuel related items and purchased energy (Minnesota, North Dakota and South Dakota).
Purchased Gas Adjustment	Provides for prospective monthly rate adjustments in Minnesota and North Dakota for costs of purchased natural gas, transportation and storage service. Includes a true-up process for difference between projected and actual costs.
GUIC Rider	Recovers costs for transmission and distribution pipeline integrity management programs, including funding for pipeline assessments, deferred costs for sewer separation and pipeline integrity management programs in Minnesota. The statute authorizing the GUIC Rider is set to expire June 30, 2023.
Sales True-up	NSP-Minnesota has historically had a sales true-up mechanism for all electric customer classes which ended in 2021. We are requesting implementation of a new sales true-up mechanism for 2022 - 2024. These mechanisms mitigate the impact of changes to sales levels as compared to a baseline.

[(a)] Minnesota state law requires NSP-Minnesota to spend 2% of its state electric revenues and 0.5% of its state natural gas revenues on CIP. These costs are recovered through an annual cost-recovery mechanism.

Pending and Recently Concluded Regulatory Proceedings

2022 Minnesota Electric Rate Case — In October 2021, NSP-Minnesota filed a three-year electric rate case with the MPUC. The request is based on a ROE of 10.2%, a 52.5% equity ratio and forward test years.

In December 2021, the MPUC approved interim rates, subject to refund, of $247 million, effective Jan. 1, 2022. In November 2022, NSP-Minnesota revised its rate request to $498 million over three years.

The revised request is detailed as follows:

(Amounts in Millions)	2022	2023	2024	Total
Rate request (annual increase)	$ 234	$ 94	$ 170	$ 498
Rate base	$ 10,923	$ 11,425	$ 11,902	N/A

In 2022, several parties filed testimony with various recommendations. The DOC provided the following recommendations in surrebuttal testimony.

	2022	2023	2024
NSP-Minnesota's filed base revenue request	$ 396	$ 546	$ 677
Recommended adjustments:			
Rate base and rate of return	(72)	(65)	(65)
MISO capacity credits	(66)	(112)	(111)
Sales forecast update	(51)	—	—
Monticello and wind farm life extension	(21)	(54)	(51)
PTC forecast	(28)	(1)	(1)
Property tax	(14)	(23)	(34)
Prepaid pension asset and liability	(13)	(21)	(32)
O&M expenses	(37)	(39)	(44)
Sherco 3 and King remaining life	—	29	28
Other, net	(23)	(33)	(43)
Total adjustments	(325)	(319)	(353)
Total proposed revenue change	$ 71	$ 227	$ 324

Next steps in the procedural schedule are expected to be as follows:

- ALJ Report: March 31, 2023.
- MPUC Order: June 30, 2023.

2022 Minnesota Natural Gas Rate Case — In November 2021, NSP-Minnesota filed a request with the MPUC for a natural gas rate increase of $36 million, or 6.6%. The filing is based on a 2022 forecast test year and includes a requested ROE of 10.5%, an equity ratio of 52.5% and a rate base of $934 million. In December 2021, the MPUC approved an interim rate increase of $25 million, subject to refund, effective Jan. 1, 2022.

In October 2022, NSP-Minnesota and various parties filed an uncontested settlement, which includes the following key terms:

- Base rate revenue increase of $21 million, with a true up to weather normalized actual sales for 2022.
- Revenue decoupling mechanism.
- Symmetrical property tax true-up.
- ROE of 9.57%.
- Equity ratio of 52.5%.

In December 2022, the ALJ recommended MPUC approval of the settlement. A MPUC decision is expected in the first half of 2023.

2021 North Dakota Natural Gas Rate Case — In September 2021, NSP-Minnesota filed a request with the NDPSC for a natural gas rate increase of $7 million, or 10.5%. The filing is based on a ROE of 10.5%, an equity ratio of 52.54%, a 2022 forecast test year and rate base of $124 million. Interim rates of $7 million, subject to refund, were implemented on Nov. 1, 2021.

In May 2022, NSP-Minnesota and NDPSC Staff reached a settlement, which reflects a rate increase of $5 million, based on a 9.8% ROE and 52.54% equity ratio. In October 2022, the NDPSC approved the settlement and final rates were implemented on Nov. 1, 2022.

South Dakota Electric Rate Case — In June 2022, NSP-Minnesota filed a South Dakota electric rate case seeking a revenue increase of approximately $44 million. The filing is based on a 2021 historic test year adjusted for certain known and measurable changes for 2022 and 2023, a ROE of 10.75%, rate base of approximately $947 million and an equity ratio of 53%. Interim rates were implemented on Jan. 1, 2023. Final rates are expected to be approved by the SDPUC in mid-2023.

Wind Repowering — In January 2021, the MPUC approved NSP-Minnesota's request for the repowering of 651 MW of owned wind projects. Two of the four repowering projects, where construction has not yet begun (in-service dates in 2025), now expect costs in excess of the original approval. While the capital costs have increased, the passage of the IRA and other changes result in a levelized cost of energy that is approximately 30% lower than the original approval.

In October 2022, NSP-Minnesota filed a request with the MPUC seeking approval of the higher capital costs for these repowering projects. In February 2023, the DOC filed comments recommending approval of recovery of the increased costs of these projects through the RES Rider. A final decision is pending.

2022 Upper Midwest RFP — In August 2022, NSP-Minnesota launched a RFP for 900 MW of solar or solar-plus-storage hybrid resources to come online by the end of 2025, including up to 300 MW of capacity to reuse the Sherco Unit 2 interconnection rights when the coal facility retires at the end of 2023.

NSP-Minnesota completed its bid evaluation process in December 2022 and will file for approval of the selected projects in early 2023.

2022 Minnesota Electric Vehicle Proposal — In August 2022, NSP-Minnesota filed a request with the MPUC for approval of approximately $320 million of capital investments (2022 through 2026) to support a public charging network, electric school bus pilot, and other expansions and modifications to its residential and commercial electric vehicle programs.

In October 2022, the MPUC referred the matter to the Office of Administrative Hearings to conduct a contested case on the proposals. In February 2023, other parties to the contested proceeding filed their direct testimony ranging in levels of support / opposition to the proposals. The evidentiary hearing is scheduled in Q2 2023 with a report from the ALJ expected in Q3 2023. A MPUC decision is expected in late 2023.

Nuclear Power Operations

Nuclear power plant operations produce gaseous, liquid and solid radioactive wastes, which are covered by federal regulation. High-level radioactive wastes primarily include used nuclear fuel. Low-level waste consists primarily of demineralizer resins, paper, protective clothing, rags, tools and equipment contaminated through use.

NRC Regulation — The NRC regulates nuclear operations. Costs of complying with NRC requirements can affect both operating expenses and capital investments of the plants. NSP-Minnesota has obtained recovery of these compliance costs and expects to recover future compliance costs.

Low-Level Waste Disposal — Low level waste from Monticello and PI is disposed of at the Clive facility located in Utah and the Waste Control Specialists facility in Texas. NSP-Minnesota has storage capacity available on-site at PI and Monticello which would allow both plants to continue to operate until the end of their current licensed lives if off-site low-level waste disposal facilities become unavailable.

High-Level Radioactive Waste Disposal — The federal government has responsibility to permanently dispose of domestic spent nuclear fuel and other high-level radioactive wastes. The Nuclear Waste Policy Act requires the DOE to implement a program for nuclear high-level waste management.

This includes the siting, licensing, construction and operation of a repository for spent nuclear fuel from civilian nuclear power reactors and other high-level radioactive wastes at a permanent federal storage or disposal facility. Currently, there are no definitive plans for a permanent federal storage facility site.

Nuclear Spent Fuel Storage — NSP-Minnesota has interim on-site storage for spent nuclear fuel at its Monticello and PI nuclear generating plants. Authorized storage capacity is sufficient to allow NSP-Minnesota to operate until the end of the operating licenses in 2030 for Monticello, 2033 for PI Unit 1, and 2034 for PI Unit 2.

In September 2021, NSP-Minnesota filed an application for a CON for additional spent fuel storage (existing Independent spent fuel storage installation) at the Monticello Nuclear Power Generating Plant to allow continued operation of the Monticello Plant until 2040.

A decision is expected in late 2023. Authorizations for additional spent fuel storage capacity may be required at each site to support either continued operation or decommissioning if the federal government does not commence storage operations.

In February 2023, NSP-Minnesota also filed an application with the NDPSC for an Advance Determination of Prudence for continued operation of the Monticello Plant until at least 2040. A decision is expected in 2023.

Wholesale and Commodity Marketing Operations

NSP-Minnesota conducts wholesale marketing operations, including the purchase and sale of electric capacity, energy, ancillary services and energy-related products. NSP-Minnesota uses physical and financial instruments to minimize commodity price risk and to hedge sales and purchases.

NSP-Minnesota also engages in trading activity unrelated to these hedging activities. Sharing of any margins is determined through state regulatory proceedings as well as the operation of the FERC approved joint operating agreement. NSP-Minnesota does not serve any wholesale requirements customers at cost-based regulated rates.

Other

Supply Chain

NSP-Minnesota's ability to meet customer energy requirements, respond to storm-related disruptions and execute our capital expenditure program are dependent on maintaining an efficient supply chain. Manufacturing processes have experienced disruptions related to scarcity of certain raw materials and interruptions in production and shipping. These disruptions have been further exacerbated by inflationary pressures, labor shortages and the impact of international conflicts/issues. NSP-Minnesota continues to monitor the situation as it remains fluid and seeks to mitigate the impacts by securing alternative suppliers, modifying design standards, and adjusting the timing of work.

Electric Distribution and Transmission Transformers

The availability of certain transformers is an industry-wide issue that has been significantly impacted and in some cases may result in delays in projects and new customer connections. NSP-Minnesota continues to seek alternative suppliers and prioritize work plans to mitigate impacts of supply constraints.

Solar Resources

In April 2022, the U.S. Department of Commerce initiated an anti-circumvention investigation that would subject CSPV solar panels and cells imported from Malaysia, Vietnam, Thailand, and Cambodia with potential incremental tariffs ranging from 50% to 250%. These countries account for more than 80% of CSPV panel imports.

An interim stay on tariffs has been issued and many significant solar projects have resumed with modified costs and projected in-service dates, including the Sherco Solar facility. Further policy action or other restrictions on solar imports (i.e., as a result of implementation of the Uyghur Forced Labor Protection Act) could impact project timelines and costs.

MISO Capacity Credits

The NSP System offered 1,500 MW of excess capacity into the MISO planning resource auction for June 2022 through May 2023. Due to a projected overall capacity shortfall in the MISO region, the 1,500 MWs offered cleared the auction at maximum pricing, generating revenues of approximately $90 million in 2022, with approximately $60 million expected in 2023. These amounts mitigate customer rate increases or are returned through earnings sharing or other mechanisms.

Inflation Reduction Act

In August 2022, the IRA was signed into law.

Key provisions impacting NSP-Minnesota include:

- Extends current PTC and ITC for renewable technologies (e.g., wind and solar).
- Restores full value of the PTC and ITC for qualifying facilities placed in-service after 2021.
- Creates a PTC for solar, clean hydrogen and nuclear.
- Establishes an ITC for energy storage, microgrids, interconnection facilities, etc.
- Allows companies to monetize or sell credits to unrelated parties.

NSP-Minnesota anticipates the IRA will drive significant customer savings for both new and existing Company owned renewable projects, assuming appropriate regulatory mechanisms and development of a market for the sale of tax credits. The IRA is expected to allow NSP-Minnesota to monetize tax credits more efficiently with the incremental benefits passed through to customers.

The IRA creates a nuclear PTC beginning in 2024 that may also provide additional savings to NSP System customers, depending on locational marginal pricing, as well as constructive U.S. Treasury guidance regarding computation of the credits.

In addition, the IRA created a new corporate AMT. NSP-Minnesota does not anticipate AMT having a material cash impact based on current estimates and our interpretation of AMT application.

Winter Storm Uri

In February 2021, the United States experienced Winter Storm Uri. Extreme cold temperatures impacted certain operational assets as well as the availability of renewable generation. The cold weather also affected the country's supply and demand for natural gas. These factors contributed to extremely high market prices for natural gas and electricity. As a result of the extremely high market prices, NSP-Minnesota incurred net natural gas, fuel and purchased energy costs of approximately $230 million (largely deferred as regulatory assets).

NSP-Minnesota received approval of recovery in North Dakota from the NDPSC in 2021. Winter Storm Uri had no impact on South Dakota electric costs as NSP-Minnesota was a net seller in the market.

In 2021, NSP-Minnesota filed with the MPUC seeking recovery of $215 million in incremental costs from natural gas customers. In August 2021, the MPUC allowed recovery of $36 million of ordinary costs over 12 months through the PGA and of $179 million of costs deemed to be extraordinary (with no financing charge) starting in September 2021, pending a prudency review. The C&I class ($82 million) will be recovered over 27 months and the residential class ($97 million) will be recovered over a 63-month recovery period.

In May 2022, the ALJs found the Winter Storm Uri fuel costs were prudently incurred and recommended no disallowances. In August 2022, the MPUC approved recovery of Uri storm costs with a $19 million disallowance.

ITEM 7A — QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Derivatives, Risk Management and Market Risk

NSP-Minnesota is exposed to a variety of market risks in the normal course of business. Market risk is the potential loss that may occur as a result of adverse changes in the market or fair value for a particular instrument or commodity. All financial and commodity-related instruments, including derivatives, are subject to market risk.

NSP-Minnesota is exposed to the impact of adverse changes in price for energy and energy-related products, which is partially mitigated by the use of commodity derivatives. In addition to ongoing monitoring and maintaining credit policies intended to minimize overall credit risk, management takes steps to mitigate changes in credit and concentration risks associated with its derivatives and other contracts, including parental guarantees and requests of collateral. While NSP-Minnesota expects that the counterparties will perform on the contracts underlying its derivatives, the contracts expose NSP-Minnesota to credit and non-performance risk.

Distress in the financial markets may impact counterparty risk and the fair value of the securities in the nuclear decommissioning fund and pension fund.

Commodity Price Risk — We are exposed to commodity price risk in our electric and natural gas operations. Commodity price risk is managed by entering into long and short-term physical purchase and sales contracts for electric capacity, energy and energy-related products and fuels used in generation and distribution activities.

Commodity price risk is also managed through the use of financial derivative instruments. Our risk management policy allows us to manage commodity price risk within each rate-regulated operation per commission approved hedge plans.

Wholesale and Commodity Trading Risk — NSP-Minnesota conducts various wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy, energy-related instruments and natural gas-related instruments, including derivatives. NSP-Minnesota's risk management policy allows management to conduct these activities within guidelines and limitations as approved by its risk management committee.

Fair value of net commodity trading contracts as of Dec. 31, 2022:

	Futures/ Forwards Maturity				
(Millions of Dollars)	Less Than 1 Year	1 to 3 Years	4 to 5 Years	Greater Than 5 Years	Total Fair Value
NSP-Minnesota [a]	$ (8)	$ (6)	$ (7)	$ (2)	$ (23)
NSP-Minnesota [b]	5	(4)	—	(3)	(2)
	$ (3)	$ (10)	$ (7)	$ (5)	$ (25)

	Options Maturity				
(Millions of Dollars)	Less Than 1 Year	1 to 3 Years	4 to 5 Years	Greater Than 5 Years	Total Fair Value
NSP-Minnesota [b]	$ —	$ —	$ —	$ 15	$ 15

(a) Prices actively quoted or based on actively quoted prices.
(b) Prices based on models and other valuation methods.

Changes in the fair value of commodity trading contracts before the impacts of margin-sharing for the years ended Dec. 31:

(Millions of Dollars)	2022	2021
Fair value of commodity trading net contracts outstanding at Jan. 1	$ (18)	$ (8)
Contracts realized or settled during the period	(7)	(58)
Commodity trading contract additions and changes during the period	15	48
Fair value of commodity trading net contracts outstanding at Dec. 31	$ (10)	$ (18)

A 10% increase and 10% decrease in forward market prices for NSP-Minnesota's commodity trading contracts would have likewise increased and decreased pretax income from continuing operations, by approximately $2 million at Dec. 31, 2022 and $3 million at Dec. 31, 2021. Market price movements can exceed 10% under abnormal circumstances.

NSP-Minnesota's commodity trading operations measure the outstanding risk exposure to price changes on contracts and obligations using an industry standard methodology known as VaR. VaR expresses the potential change in fair value of the outstanding contracts and obligations over a particular period of time under normal market conditions.

The VaRs for the NSP-Minnesota and PSCo commodity trading operations, excluding both non-derivative transactions and derivative transactions designated as normal purchases and normal sales, calculated on a consolidated basis using a Monte Carlo simulation with a 95% confidence level and a one-day holding period, were as follows:

(Millions of Dollars)	Year Ended Dec. 31	Average	High	Low
2022	$ 2	$ 1	$ 5	$ —
2021	$ 1	$ 2	$ 52	$ 1

A short-term increase in VaR occurred during the week of Feb. 12, 2021 through Feb. 18, 2021. On Feb. 17, 2021, the portfolio VaR reached a high of $52 million. This increase in VaR was driven by the unprecedented market conditions during Winter Storm Uri. Prior to this weather event, VaR was $1 million and returned to $1 million by Feb. 19, 2021.

Nuclear Fuel Supply — NSP-Minnesota has contracted for its 2023 and 2024 enriched nuclear material requirements, which are in various stages of processing in Canada, Europe, and the United States. NSP-Minnesota is scheduled to take delivery of approximately 26% of its average enriched nuclear material requirements from Russia through 2030. We are closely monitoring the evolving situation in Ukraine and its global impacts. NSP-Minnesota is in the process of entering into new contracts to reduce the risk of supply interruptions of nuclear material from Russia. NSP-Minnesota will take additional further action to reduce this risk as necessary.

Interest Rate Risk — NSP-Minnesota is subject to interest rate risk. NSP-Minnesota's risk management policy allows interest rate risk to be managed through the use of fixed rate debt, floating rate debt and interest rate derivatives.

A 100-basis-point change in the benchmark rate on NSP-Minnesota's variable rate debt would impact pretax interest expense annually by approximately $2 million and an immaterial amount in 2022 and 2021, respectively.

NSP-Minnesota maintains a nuclear decommissioning fund, as required by the NRC. The nuclear decommissioning fund is subject to interest rate and equity price risk. The fund is invested in a diversified portfolio of cash equivalents, debt securities, equity securities and other investments. These investments may be used only for the purpose of decommissioning NSP-Minnesota's nuclear generating plants.

Fluctuations in equity prices or interest rates affecting the nuclear decommissioning fund do not have a direct impact on earnings due to the application of regulatory accounting. Realized and unrealized gains on the decommissioning fund investments are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs.

The value of pension and postretirement plan assets and benefit costs are impacted by changes in discount rates and expected return on plan assets. NSP-Minnesota's ongoing pension and postretirement investment strategy is based on plan-specific investment recommendations that seek to optimize potential investment risk and minimize interest rate risk associated with changes in the obligations as a plan's funded status increases over time. The impacts of fluctuations in interest rates on pension and postretirement costs are mitigated by pension cost calculation methodologies and regulatory mechanisms that minimize the earnings impacts of such changes.

Credit Risk — NSP-Minnesota is also exposed to credit risk. Credit risk relates to the risk of loss resulting from counterparties' nonperformance on their contractual obligations. NSP-Minnesota maintains credit policies intended to minimize overall credit risk and actively monitors these policies to reflect changes and scope of operations.

At Dec. 31, 2022, a 10% increase in commodity prices would have resulted in an increase in credit exposure of $30 million, while a decrease in prices of 10% would have resulted in a decrease in credit exposure of $29 million. At Dec. 31, 2021, a 10% increase in commodity prices would have resulted in an increase in credit exposure of $28 million, while a decrease in prices of 10% would have resulted in an decrease in credit exposure of $18 million.

NSP-Minnesota conducts credit reviews for all wholesale, trading and non-trading commodity counterparties and employs credit risk controls, such as letters of credit, parental guarantees, master netting agreements and termination provisions. Credit exposure is monitored and, when necessary, the activity with a specific counterparty is limited until credit enhancement is provided. Distress in the financial markets could increase NSP-Minnesota's credit risk.

Fair Value Measurements

Derivative contracts, with the exception of those designated as normal purchases and normal sales, are reported at fair value. NSP-Minnesota's investments held in the nuclear decommissioning fund, rabbi trusts, pension and other postretirement funds are also subject to fair value accounting. See Notes 8 and 9 to the consolidated financial statements for further information.

ITEM 8 — FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

See Item 15-1 for an index of financial statements included herein.

See Note 14 to the consolidated financial statements for further information.

Management Report on Internal Control Over Financial Reporting

The management of NSP-Minnesota is responsible for establishing and maintaining adequate internal control over financial reporting. NSP-Minnesota's internal control system was designed to provide reasonable assurance to Xcel Energy Inc.'s and NSP-Minnesota's management and board of directors regarding the preparation and fair presentation of published financial statements.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

NSP-Minnesota management assessed the effectiveness of NSP-Minnesota's internal control over financial reporting as of Dec. 31, 2022. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control — Integrated Framework (2013).* Based on our assessment, we believe that, as of Dec. 31, 2022, NSP-Minnesota's internal control over financial reporting is effective at the reasonable assurance level based on those criteria.

/s/ ROBERT C. FRENZEL	/s/ BRIAN J. VAN ABEL
Robert C. Frenzel	Brian J. Van Abel
Chairman, Chief Executive Officer and Director	Executive Vice President, Chief Financial Officer and Director
Feb. 23, 2023	Feb. 23, 2023

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the stockholder and the Board of Directors of Northern States Power Company, a Minnesota corporation

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Northern States Power Company, a Minnesota corporation and subsidiaries (the "Company") as of December 31, 2022 and 2021, the related consolidated statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2022, and the related notes and the schedule listed in the Index at Item 15 (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2022 and 2021, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2022, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Regulatory Assets and Liabilities - Impact of Rate Regulation on the Financial Statements — Refer to Notes 4 and 10 to the consolidated financial statements.

Critical Audit Matter Description

The Company is subject to rate regulation by state utility regulatory agencies, which have jurisdiction with respect to the rates of electric distribution companies in Minnesota, North Dakota and South Dakota, and natural gas distribution companies in Minnesota and North Dakota. The Company is also subject to the jurisdiction of the Federal Energy Regulatory Commission for its wholesale electric operations, hydroelectric generation licensing, accounting practices, wholesale sales for resale, transmission of electricity in interstate commerce, compliance with North American Electric Reliability Corporation standards, asset transactions and mergers and natural gas transactions in interstate commerce, (collectively with state utility regulatory agencies, the "Commissions"). Management has determined it meets the requirements under accounting principles generally accepted in the United States of America to prepare its financial statements applying the specialized rules to account for the effects of cost-based rate regulation. Accounting for the economics of rate regulation affects multiple financial statement line items and disclosures, including property, plant and equipment, regulatory assets and liabilities, operating revenues and expenses, and income taxes.

The Company is subject to regulatory rate setting processes. Rates are determined and approved in regulatory proceedings based on an analysis of the Company's costs to provide utility service and a return on, and recovery of, the Company's investment in assets required to deliver services to customers. Accounting for the Company's regulated operations provides that rate-regulated entities report assets and liabilities consistent with the recovery of those incurred costs in rates, if it is probable that such rates will be charged and collected. The Commissions' regulation of rates is premised on the full recovery of incurred costs and a reasonable rate of return on invested capital. Decisions by the Commissions in the future will impact the accounting for regulated operations, including decisions about the amount of allowable costs and return on invested capital included in rates and any refunds that may be required. In the rate setting process, the Company's rates result in the recording of regulatory assets and liabilities based on the probability of future cash flows. Regulatory assets generally represent incurred or accrued costs that have been deferred because future recovery from customers is probable. Regulatory liabilities generally represent amounts that are expected to be refunded to customers in future rates or amounts collected in current rates for future costs.

We identified the impact of rate regulation as a critical audit matter due to the significant judgments made by management to support its assertions about impacted account balances and disclosures and the high degree of subjectivity involved in assessing the impact of future regulatory orders on the financial statements. Management judgments include assessing the likelihood of (1) recovery in future rates of incurred costs, (2) a disallowance of part of the cost of recently completed plant, and 3) a refund due to customers. Given that management's accounting judgments are based on assumptions about the outcome of future decisions by the Commissions, auditing these judgments required specialized knowledge of accounting for rate regulation and the rate setting process due to its inherent complexities.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the uncertainty of future decisions by the Commissions included the following, among others:

- We tested the effectiveness of management's controls over the evaluation of the likelihood of (1) the recovery in future rates of costs deferred as regulatory assets, and (2) a refund or a future reduction in rates that should be reported as regulatory liabilities. We also tested the effectiveness of management's controls over the recognition of regulatory assets or liabilities and the monitoring and evaluation of regulatory developments that may affect the likelihood of recovering costs in future rates or of a future reduction in rates.
- We evaluated the Company's disclosures related to the impacts of rate regulation, including the balances recorded and regulatory developments.
- We read relevant regulatory orders issued by the Commissions for the Company, regulatory statutes, interpretations, procedural schedules and memorandums, filings made by intervenors, experts' testimony and other publicly available information to assess the likelihood of recovery in future rates or of a future reduction in rates based on precedents of the Commissions' treatment of similar costs under similar circumstances. We also evaluated regulatory filings for any evidence that intervenors are challenging full recovery of the cost of any capital projects. If the full recovery of project costs is being challenged by intervenors, we evaluated management's assessment of the probability of a disallowance. We evaluated the external information and compared to the Company's recorded regulatory assets and liabilities for completeness.
- We obtained management's analysis and correspondence from counsel, as appropriate, regarding regulatory assets or liabilities not yet addressed in a regulatory order to assess management's assertion that amounts are probable of recovery or a future reduction in rates.

/s/ DELOITTE & TOUCHE LLP
Minneapolis, Minnesota
February 23, 2023

We have served as the Company's auditor since 2002.

NSP-MINNESOTA AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
(amounts in millions)

	Year Ended Dec. 31		
	2022	2021	2020
Operating revenues			
Electric, non-affiliates	$ 5,103	$ 4,593	$ 4,131
Electric, affiliates	514	501	440
Natural gas	1,022	623	493
Other	45	39	37
Total operating revenues	6,684	5,756	5,101
Operating expenses			
Electric fuel and purchased power	2,416	2,042	1,626
Cost of natural gas sold and transported	741	385	263
Cost of sales — other	26	23	22
Operating and maintenance expenses	1,228	1,190	1,191
Conservation program expenses	163	144	119
Depreciation and amortization	1,014	926	825
Taxes (other than income taxes)	276	264	259
Total operating expenses	5,864	4,974	4,305
Operating income	820	782	796
Other (expense) income, net	(7)	4	2
Allowance for funds used during construction — equity	29	30	25
Interest charges and financing costs			
Interest charges — includes other financing costs of $8, $8 and $8, respectively	291	271	249
Allowance for funds used during construction — debt	(12)	(13)	(11)
Total interest charges and financing costs	279	258	238
Income before income taxes	563	558	585
Income tax benefit	(112)	(48)	(6)
Net income	$ 675	$ 606	$ 591

See Notes to Consolidated Financial Statements

NSP-MINNESOTA AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(amounts in millions)

	Year Ended Dec. 31		
	2022	**2021**	**2020**
Net income	$ 675	$ 606	$ 591
Other comprehensive income			
Pension and retiree medical benefits:			
Net pension and retiree medical gain arising during the period, net of tax of $—	1	—	—
Derivative instruments:			
Reclassification of losses to net income, net of tax of $—	1	2	1
Total other comprehensive income	2	2	1
Total comprehensive income	$ 677	$ 608	$ 592

See Notes to Consolidated Financial Statements

NSP-MINNESOTA AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(amounts in millions)

	Year Ended Dec. 31		
	2022	2021	2020
Operating activities			
Net income	$ 675	$ 606	$ 591
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation and amortization	1,021	932	831
Nuclear fuel amortization	118	114	123
Deferred income taxes	(214)	(36)	(67)
Allowance for equity funds used during construction	(29)	(30)	(25)
Provision for bad debts	21	24	24
Changes in operating assets and liabilities:			
Accounts receivable	(102)	(89)	(55)
Accrued unbilled revenues	(53)	(71)	1
Inventories	(85)	(22)	(14)
Other current assets	(4)	3	(9)
Accounts payable	46	69	(1)
Net regulatory assets and liabilities	443	(282)	(87)
Other current liabilities	39	(5)	(58)
Pension and other employee benefit obligations	(11)	(41)	(54)
Other, net	6	(50)	(8)
Net cash provided by operating activities	1,871	1,122	1,192
Investing activities			
Capital/construction expenditures	(1,901)	(1,866)	(1,901)
Purchase of investment securities	(1,332)	(757)	(1,398)
Proceeds from the sale of investment securities	1,297	743	1,378
Investments in utility money pool arrangement	(1,522)	(821)	(718)
Repayments from utility money pool arrangement	1,613	730	718
Other, net	6	1	1
Net cash used in investing activities	(1,839)	(1,970)	(1,920)
Financing activities			
Proceeds from (repayments of) short-term borrowings, net	207	(179)	149
Borrowings under utility money pool arrangement	6	434	136
Repayments under utility money pool arrangement	(6)	(434)	(136)
Proceeds from issuance of long-term debt	489	836	677
Repayment of long-term debt	(300)	—	(300)
Capital contributions from parent	124	649	527
Dividends paid to parent	(560)	(431)	(408)
Other, net	—	—	3
Net cash (used in) provided by financing activities	(40)	875	648
Net change in cash, cash equivalents and restricted cash	(8)	27	(80)
Cash, cash equivalents and restricted cash at beginning of period	73	46	126
Cash, cash equivalents and restricted cash at end of period	$ 65	$ 73	$ 46
Supplemental disclosure of cash flow information:			
Cash paid for interest (net of amounts capitalized)	$ (268)	$ (245)	$ (230)
Cash (paid) received for income taxes, net	(100)	11	(53)
Supplemental disclosure of non-cash investing and financing transactions:			
Accrued property, plant and equipment additions	$ 208	$ 242	$ 74
Inventory transfers to property, plant and equipment	10	8	24
Operating lease right-of-use assets	1	4	2
Allowance for equity funds used during construction	29	30	25

See Notes to Consolidated Financial Statements

NSP-MINNESOTA AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(amounts in millions, except share and per share data)

	Dec. 31 2022	Dec. 31 2021
Assets		
Current assets		
Cash and cash equivalents	$ 65	$ 73
Accounts receivable, net	534	429
Accounts receivable from affiliates	45	29
Investments in money pool arrangements	—	91
Accrued unbilled revenues	372	319
Inventories	384	309
Regulatory assets	384	527
Derivative instruments	89	53
Prepayments and other	62	46
Total current assets	1,935	1,876
Property, plant and equipment, net	17,478	16,430
Other assets		
Nuclear decommissioning fund and other investments	2,930	3,308
Regulatory assets	894	718
Derivative instruments	68	33
Operating lease right-of-use assets	324	408
Other	29	36
Total other assets	4,245	4,503
Total assets	$ 23,658	$ 22,809
Liabilities and Equity		
Current liabilities		
Current portion of long-term debt	$ 400	$ 300
Short-term debt	207	—
Accounts payable	619	522
Accounts payable to affiliates	89	63
Regulatory liabilities	191	117
Taxes accrued	272	260
Accrued interest	79	78
Dividends payable to parent	122	96
Derivative instruments	42	35
Operating lease liabilities	98	90
Other	227	166
Total current liabilities	2,346	1,727
Deferred credits and other liabilities		
Deferred income taxes	1,666	1,949
Deferred investment tax credits	15	17
Regulatory liabilities	1,983	1,927
Asset retirement obligations	2,727	2,585
Derivative instruments	102	71
Pension and employee benefit obligations	155	112
Operating lease liabilities	256	353
Other	30	48
Total deferred credits and other liabilities	6,934	7,062
Commitments and contingencies		
Capitalization		
Long-term debt	6,542	6,447
Common stock — 5,000,000 shares authorized of $0.01 par value; 1,000,000 shares outstanding at Dec. 31, 2022 and Dec. 31, 2021, respectively	—	—
Additional paid in capital	5,374	5,202
Retained earnings	2,480	2,391
Accumulated other comprehensive loss	(18)	(20)
Total common stockholder's equity	7,836	7,573
Total liabilities and equity	$ 23,658	$ 22,809

See Notes to Consolidated Financial Statements

NSP-MINNESOTA AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
(amounts in millions, except share data)

	Common Stock: Shares	Common Stock: Par Value	Common Stock: Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Common Stockholder's Equity
Balance at Dec. 31, 2019	1,000,000	$ —	$ 4,068	$ 2,036	$ (23)	$ 6,081
Net income				591		591
Other comprehensive income					1	1
Dividends declared to parent				(420)		(420)
Contribution of capital by parent			517			517
Adoption of ASC Topic 326				(1)		(1)
Balance at Dec. 31, 2020	1,000,000	$ —	$ 4,585	$ 2,206	$ (22)	$ 6,769
Net income				606		606
Other comprehensive income					2	2
Dividends declared to parent				(421)		(421)
Contribution of capital by parent			617			617
Balance at Dec. 31, 2021	1,000,000	$ —	$ 5,202	$ 2,391	$ (20)	$ 7,573
Net income				675		675
Other comprehensive income					2	2
Dividends declared to parent				(586)		(586)
Contribution of capital by parent			172			172
Balance at Dec. 31, 2022	1,000,000	$ —	$ 5,374	$ 2,480	$ (18)	$ 7,836

See Notes to Consolidated Financial Statements

NORTHERN STATES POWER COMPANY - MINNESOTA
Notes to Consolidated Financial Statements

1. Summary of Significant Accounting Policies

General — NSP-Minnesota is engaged in the regulated generation, purchase, transmission, distribution and sale of electricity and the regulated purchase, transportation, distribution and sale of natural gas.

NSP-Minnesota's consolidated financial statements include its wholly-owned subsidiaries. In the consolidation process, all intercompany transactions and balances are eliminated. NSP-Minnesota has investments in certain plants and transmission facilities jointly owned with nonaffiliated utilities.

NSP-Minnesota's proportionate share of jointly owned facilities is recorded as property, plant and equipment on the consolidated balance sheets and NSP-Minnesota's proportionate share of operating costs associated with these facilities is included in its consolidated statements of income.

NSP-Minnesota's consolidated financial statements are presented in accordance with GAAP. All of NSP-Minnesota's underlying accounting records also conform to the FERC uniform system of accounts or to systems required by various state regulatory commissions. Certain amounts in the consolidated financial statements or notes have been reclassified for comparative purposes; however, such reclassifications did not affect net income, total assets, liabilities, equity or cash flows.

NSP-Minnesota has evaluated events occurring after Dec. 31, 2022 up to the date of issuance of these consolidated financial statements. These statements contain all necessary adjustments and disclosures resulting from that evaluation.

Use of Estimates — NSP-Minnesota uses estimates based on the best information available in recording transactions and balances resulting from business operations.

Estimates are used for items such as plant depreciable lives or potential disallowances, AROs, certain regulatory assets and liabilities, tax provisions, uncollectible amounts, environmental costs, unbilled revenues, jurisdictional fuel and energy cost allocations and actuarially determined benefit costs. Recorded estimates are revised when better information becomes available or actual amounts can be determined. Revisions can affect operating results.

Regulatory Accounting — NSP-Minnesota accounts for income and expense items in accordance with accounting guidance for regulated operations. Under this guidance:

- Certain costs, which would otherwise be charged to expense or other comprehensive income, are deferred as regulatory assets based on the expected ability to recover the costs in future rates.
- Certain credits, which would otherwise be reflected as income or other comprehensive income, are deferred as regulatory liabilities based on the expectation the amounts will be returned to customers in future rates, or because the amounts were collected in rates prior to the costs being incurred.

Estimates and assumptions for recovery of deferred costs and refund of deferred credits are based on specific ratemaking decisions, precedent or other information available. Regulatory assets and liabilities are amortized consistent with the treatment in the rate setting process.

If changes in the regulatory environment occur, NSP-Minnesota may no longer be eligible to apply this accounting treatment and may be required to eliminate regulatory assets and liabilities. Such changes could have a material effect on NSP-Minnesota's results of operations, financial condition and cash flows.

See Note 4 for further information.

Income Taxes — NSP-Minnesota accounts for income taxes using the asset and liability method, which requires recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the consolidated financial statements. Income taxes are deferred for all temporary differences between pretax financial and taxable income and between the book and tax bases of assets and liabilities.

NSP-Minnesota uses rates that are scheduled to be in effect when the temporary differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in the period that includes the enactment date.

The effects of tax rate changes that are attributable to the utility subsidiaries are generally subject to a normalization method of accounting. Therefore, the revaluation of most of the utility subsidiaries' net deferred taxes upon a tax rate reduction results in the establishment of a net regulatory liability, refundable to utility customers over the remaining life of the related assets. NSP-Minnesota anticipates that a tax rate increase would predominantly result in the establishment of a regulatory asset, subject to an evaluation of whether future recovery is expected.

Reversal of certain temporary differences are accounted for as current income tax expense due to the effects of past regulatory practices when deferred taxes were not required to be recorded due to the use of flow through accounting for ratemaking purposes.

Tax credits are recorded when earned unless there is a requirement to defer the benefit and amortize over the book depreciable lives of the related property. The requirement to defer and amortize these credits specifically applies to certain federal ITCs, as determined by tax regulations and NSP-Minnesota tax elections. For tax credits otherwise eligible to be recognized when earned, NSP-Minnesota considers the impact of rate regulation to determine if these credits and related adjustments should be deferred as regulatory assets or liabilities.

Deferred tax assets are reduced by a valuation allowance if it is more likely than not that some portion or all of the deferred tax asset will not be realized. Utility rate regulation has resulted in the recognition of regulatory assets and liabilities related to income taxes.

NSP-Minnesota measures and discloses uncertain tax positions that it has taken or expects to take in its income tax returns. A tax position is recognized in the consolidated financial statements when it is more likely than not that the position will be sustained upon examination based on the technical merits of the position. Recognition of changes in uncertain tax positions are reflected as a component of income tax expense.

Interest and penalties related to income taxes are reported within other (expense) income or interest charges in the consolidated statements of income.

Xcel Energy Inc. and its subsidiaries, including NSP-Minnesota file consolidated federal income tax returns as well as consolidated or separate state income tax returns. Federal income taxes paid by Xcel Energy Inc. are allocated to its subsidiaries based on separate company computations. A similar allocation is made for state income taxes paid by Xcel Energy Inc. in connection with consolidated state filings. Xcel Energy Inc. also allocates its own income tax benefits to its direct subsidiaries.

See Note 7 for further information.

Property, Plant and Equipment and Depreciation in Regulated Operations — Property, plant and equipment is stated at original cost. The cost of plant includes direct labor and materials, contracted work, overhead costs and AFUDC. The cost of plant retired is charged to accumulated depreciation and amortization. Amounts recovered in rates for future removal costs are recorded as regulatory liabilities. Significant additions or improvements extending asset lives are capitalized, while repairs and maintenance costs are charged to expense as incurred. Maintenance and replacement of items determined to be less than a unit of property are charged to operating expenses as incurred.

Property, plant and equipment is tested for impairment when it is determined that the carrying value of the assets may not be recoverable. A loss is recognized in the current period if it becomes probable that part of a cost of a plant under construction or recently completed plant will be disallowed for recovery from customers and a reasonable estimate of the disallowance can be made.

For investments in property, plant and equipment that are abandoned and not expected to go into service, incurred costs and related deferred tax amounts are compared to the discounted estimated future rate recovery, and a loss is recognized, if necessary.

Depreciation expense is recorded using the straight-line method over the plant's commission approved useful life. Actuarial life studies are performed and submitted to the state and federal commissions for review. Upon acceptance by the various commissions, the resulting lives and net salvage rates are used to calculate depreciation. Plant removal costs are typically recognized at the amounts recovered in rates as authorized by the applicable regulator. Accumulated removal costs are reflected in the consolidated balance sheet as a regulatory liability. Depreciation expense, expressed as a percentage of average depreciable property, was approximately 4.0% for 2022, 3.7% for 2021 and 3.7% for 2020.

See Note 3 for further information.

AROs — NSP-Minnesota records AROs as a liability for the fair value of an ARO to be recognized in the period incurred (if it can be reasonably estimated), with the offsetting/associated costs capitalized as a long-lived asset. The liability is generally increased over time by applying the effective interest method of accretion and the capitalized costs are typically depreciated over the useful life of the long-lived asset. Changes resulting from revisions to timing or amounts of expected asset retirement cash flows are recognized as an increase or a decrease in the ARO.

See Note 10 for further information.

Nuclear Decommissioning — Nuclear decommissioning studies that estimate NSP-Minnesota's costs of decommissioning its nuclear power plants are normally performed at least every 3 years and submitted to the state commissions for approval. Due to other regulatory activity, the next decommissioning study has been deferred one year until 2024.

NSP-Minnesota recovers regulator-approved decommissioning costs of its nuclear power plants over each facility's expected service life, typically based on the triennial decommissioning studies. The studies consider estimated future costs of decommissioning and the market value of investments in trust funds and recommend annual funding amounts. Amounts collected in rates are deposited in the trust funds. For financial reporting purposes, NSP-Minnesota accounts for nuclear decommissioning as an ARO.

Restricted funds for the payment of future decommissioning expenditures for NSP-Minnesota's nuclear facilities are included in nuclear decommissioning fund and other assets on the consolidated balance sheets.

See Notes 8 and 10 for further information.

Benefit Plans and Other Postretirement Benefits — NSP-Minnesota maintains pension and postretirement benefit plans for eligible employees. Recognizing the cost of providing benefits and measuring the projected benefit obligation of these plans requires management to make various assumptions and estimates.

Certain unrecognized actuarial gains and losses and unrecognized prior service costs or credits are deferred as regulatory assets and liabilities, rather than recorded as other comprehensive income, based on regulatory recovery mechanisms.

See Note 9 for further information.

Environmental Costs — Environmental costs are recorded when it is probable NSP-Minnesota is liable for remediation costs and the amount can be reasonably estimated. Costs are deferred as a regulatory asset if it is probable the costs will be recovered from customers in future rates. Otherwise, the costs are expensed. For certain environmental costs related to facilities currently in use, such as for emission-control equipment, the cost is capitalized and depreciated over the life of the plant.

Estimated remediation costs are regularly adjusted as estimates are revised and remediation is performed. If other participating potentially responsible parties exist and acknowledge their potential involvement with a site, costs are estimated and recorded only for NSP-Minnesota's expected share of the cost.

Future costs of restoring sites are treated as a capitalized cost of plant retirement. The depreciation expense levels recoverable in rates include a provision for removal expenses. Removal costs recovered in rates before the related costs are incurred are classified as a regulatory liability.

See Note 10 for further information.

Revenue from Contracts with Customers — Performance obligations related to the sale of energy are satisfied as energy is delivered to customers. NSP-Minnesota recognizes revenue that corresponds to the price of the energy delivered to the customer. The measurement of energy sales to customers is generally based on the reading of their meters, which occurs systematically throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated, and the corresponding unbilled revenue is recognized.

A separate financing component of collections from customers is not recognized as contract terms are short-term in nature. Revenues are net of any excise or sales taxes or fees.

NSP-Minnesota recognizes physical sales to customers (native load and wholesale) on a gross basis in electric revenues and cost of sales. Revenues and charges for short-term physical wholesale sales of excess energy transacted through RTOs are also recorded on a gross basis. Other revenues and charges settled/facilitated through an RTO are recorded on a net basis in cost of sales.

NSP-Minnesota has various rate-adjustment mechanisms that provide for the recovery of natural gas, electric fuel and purchased energy costs. Cost-adjustment tariffs may increase or decrease the level of revenue collected from customers and are revised periodically for differences between the total amount collected under the clauses and the costs incurred.

When applicable, fuel cost over-recoveries (the excess of fuel revenue billed to customers over fuel costs incurred) are deferred as regulatory liabilities and under-recoveries (the excess of fuel costs incurred over fuel revenues billed to customers) are deferred as regulatory assets.

See Note 6 for further information.

Cash and Cash Equivalents — NSP-Minnesota considers investments in instruments with a remaining maturity of 3 months or less at the time of purchase to be cash equivalents.

Accounts Receivable and Allowance for Bad Debts — Accounts receivable are stated at the actual billed amount net of an allowance for bad debts. NSP-Minnesota establishes an allowance for uncollectible receivables based on a policy that reflects its expected exposure to the credit risk of customers.

As of Dec. 31, 2022 and 2021, the allowance for bad debts was $46 million and $45 million, respectively.

Inventory — Inventory is recorded at the lower of average cost or net realizable value and consisted of the following:

(Millions of Dollars)	Dec. 31, 2022	Dec. 31, 2021
Inventories		
Materials and supplies	$ 200	$ 181
Fuel	103	81
Natural gas	81	47
Total inventories	$ 384	$ 309

Fair Value Measurements — NSP-Minnesota presents cash equivalents, interest rate derivatives, commodity derivatives and nuclear decommissioning fund assets at estimated fair values in its consolidated financial statements.

For interest rate derivatives, quoted prices based primarily on observable market interest rate curves are used to estimate fair value. For commodity derivatives, the most observable inputs available are generally used to determine the fair value of each contract. In the absence of a quoted price, quoted prices for similar contracts or internally prepared valuation models may be used to determine fair value.

For the pension and postretirement plan assets and nuclear decommissioning fund, published trading data and pricing models, generally using the most observable inputs available, are utilized to determine fair value for each security.

See Notes 8 and 9 for further information.

Derivative Instruments — NSP-Minnesota uses derivative instruments in connection with its commodity trading activities, and to manage risk associated with changes in interest rates, and utility commodity prices, including forward contracts, futures, swaps and options. Any derivative instruments not qualifying for the normal purchases and normal sales exception are recorded on the consolidated balance sheets at fair value as derivative instruments. Classification of changes in fair value for those derivative instruments is dependent on the designation of a qualifying hedging relationship.

Changes in fair value of derivative instruments not designated in a qualifying hedging relationship are reflected in current earnings or as a regulatory asset or liability. Classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms.

Gains or losses on commodity trading transactions are recorded as a component of electric operating revenues.

Normal Purchases and Normal Sales — NSP-Minnesota enters into contracts for purchases and sales of commodities for use in its operations. At inception, contracts are evaluated to determine whether they contain a derivative, and if so, whether they may be exempted from derivative accounting if designated as normal purchases or normal sales.

See Note 8 for further information.

Commodity Trading Operations — All applicable gains and losses related to commodity trading activities are shown on a net basis in electric operating revenues in the consolidated statements of income.

Commodity trading activities are not associated with energy produced from NSP-Minnesota's generation assets or energy and capacity purchased to serve native load. Commodity trading contracts are recorded at fair market value and commodity trading results include the impact of all margin-sharing mechanisms.

See Note 8 for further information.

Other Utility Items

AFUDC — AFUDC represents the cost of capital used to finance utility construction activity and is computed by applying a composite financing rate to qualified CWIP. The amount of AFUDC capitalized as a utility construction cost is credited to other nonoperating income (for equity capital) and interest charges (for debt capital). AFUDC amounts capitalized are included in NSP-Minnesota's rate base.

Alternative Revenue — Certain rate rider mechanisms (including decoupling/sales true up and CIP/DSM programs) qualify as alternative revenue programs. These mechanisms arise from instances in which the regulator authorizes a future surcharge in response to past activities or completed events. When certain criteria are met, including expected collection within 24 months, revenue is recognized, which may include incentives and return on rate base items.

Billing amounts are revised periodically for differences between total amount collected and revenue earned, which may increase or decrease the level of revenue collected from customers. Alternative revenues arising from these programs are presented on a gross basis and disclosed separately from revenue from contracts with customers.

See Note 6 for further information.

Conservation Programs — Costs incurred for CIP programs are deferred if it is probable future revenue will recover the incurred cost. Revenues recognized for incentive programs for the recovery of lost margins and/or conservation performance incentives are limited to amounts expected to be collected within 24 months from the year they are earned. Regulatory assets are recognized to reflect the amount of costs or earned incentives that have not yet been collected from customers.

Emissions Allowances — Emissions allowances are recorded at cost, including broker commission fees. The inventory accounting model is utilized for all emissions allowances and any sales of these allowances are included in electric revenues.

Nuclear Refueling Outage Costs — NSP-Minnesota uses a deferral and amortization method for nuclear refueling costs. This method amortizes costs over the period between refueling outages consistent with rate recovery.

RECs — Cost of RECs that are utilized for compliance is recorded as electric fuel and purchased power expense. An inventory accounting model is used to account for RECs.

Sales of RECs are recorded in electric revenues on a gross basis. The cost of these RECs and amounts credited to customers under margin-sharing mechanisms are recorded in electric fuel and purchased power expense.

Cost of RECs that are utilized to support commodity trading activities are recorded in a similar manner as the associated commodities and are on a net basis in electric operating revenues in the consolidated statements of income.

2. Accounting Pronouncements

As of Dec. 31, 2022, there was no material impact from the recent adoption of new accounting pronouncements, nor expected material impact from recently issued accounting pronouncements yet to be adopted, on NSP-Minnesota's consolidated financial statements.

3. Property, Plant and Equipment

Major classes of property, plant and equipment

(Millions of Dollars)	Dec. 31, 2022	Dec. 31, 2021
Property, plant and equipment, net		
Electric plant	$ 20,114	$ 19,154
Natural gas plant	2,100	1,864
Common and other property	1,156	1,007
Plant to be retired [(a)]	646	719
CWIP	907	984
Total property, plant and equipment	24,923	23,728
Less accumulated depreciation	(7,734)	(7,606)
Nuclear fuel	3,183	3,081
Less accumulated amortization	(2,894)	(2,773)
Property, plant and equipment, net	$ 17,478	$ 16,430

(a) Amounts include regulator-approved retirements of Sherco Units 1, 2 and 3 and A.S. King and are presented net of accumulated depreciation.

Joint Ownership of Generation and Transmission Facilities

Jointly owned assets as of Dec. 31, 2022:

(Millions of Dollars, Except Percent Owned)	Plant in Service	Accumulated Depreciation	Percent Owned
Electric generation:			
Sherco Unit 3	$ 623	$ 468	59 %
Sherco common facilities	180	115	80
Sherco substation	5	4	59
Electric transmission:			
Grand Meadow	11	3	50
Huntley Wilmarth	49	1	50
CapX2020	818	124	51
Total [(a)]	$ 1,686	$ 715	

(a) Projects additionally include $4 million in CWIP.

NSP-Minnesota's share of operating expenses and construction expenditures is included in the applicable utility accounts. Respective owners are responsible for providing their own financing.

4. Regulatory Assets and Liabilities

Regulatory assets and liabilities are created for amounts that regulators may allow to be collected or may require to be paid back to customers in future electric and natural gas rates. NSP-Minnesota would be required to recognize the write-off of regulatory assets and liabilities in net income or other comprehensive income if changes in the utility industry no longer allow for the application of regulatory accounting guidance under GAAP.

Components of regulatory assets:

(Millions of Dollars)	See Note(s)	Remaining Amortization Period	Dec. 31, 2022		Dec. 31, 2021 [(a)]	
Regulatory Assets			Current	Noncurrent	Current	Noncurrent
Pension and retiree medical obligations	9	Various	$ 12	$ 347	$ 24	$ 301
Recoverable deferred taxes on AFUDC		Plant lives	—	112	—	114
Excess deferred taxes — TCJA	7	Various	10	103	10	113
Deferred natural gas and electric energy/fuel costs		One to five years	110	65	138	190
Net AROs [(b)]	1, 10	Various	—	62	—	(316)
Benson biomass PPA termination and asset purchase		Six years	10	45	10	55
PI extended power uprate		12 years	4	42	4	46
Contract valuation adjustments [(c)]	1, 8	Term of related contract	16	28	18	34
Purchased power contracts costs		Term of related contract	7	19	6	27
Conservation programs [(d)]	1	One to two years	6	19	7	22
Nuclear refueling outage costs	1	One to two years	30	12	37	16
Losses on reacquired debt		Term of related debt	1	10	1	11
Sales true-up and revenue decoupling		One year	53	—	33	56
Laurentian biomass PPA termination		Less than one year	18	—	18	18
Renewable resources and environmental initiatives		One year	50	—	170	3
Gas pipeline inspection and remediation costs		One year	42	—	33	—
Other		Various	15	30	18	28
Total regulatory assets			$ 384	$ 894	$ 527	$ 718

(a) Prior period amounts have been restated to conform with current year presentation.
(b) Includes amounts recorded for future recovery of AROs, less amounts recovered through nuclear decommissioning accruals and gains from decommissioning investments.
(c) Includes the fair value of certain long-term PPAs used to meet energy capacity requirements and valuation adjustments on natural gas commodity purchases.
(d) Includes costs for conservation programs, as well as incentives allowed in certain jurisdictions.

Components of regulatory liabilities:

(Millions of Dollars)	See Note(s)	Remaining Amortization Period	Dec. 31, 2022		Dec. 31, 2021 [(a)]	
Regulatory Liabilities			Current	Noncurrent	Current	Noncurrent
Deferred income tax adjustments and TCJA refunds [(b)]	7	Various	$ 6	$ 1,200	$ 9	$ 1,256
Plant removal costs	1, 10	Various	—	693	—	613
Revenue decoupling		Two years	—	22	—	—
Renewable resources and environmental initiatives		Various	6	19	1	10
ITC deferrals	1	Various	—	17	—	7
Formula rates		One to two years	6	9	4	7
Contract valuation adjustments [(c)]	1, 8	Less than one year	56	—	29	—
Conservation programs		Less than one year	42	—	—	—
DOE Settlement		N/A	—	—	14	—
Deferred natural gas and electric energy/fuel costs		Less than one year	26	—	14	—
Other		Various	49	23	46	34
Total regulatory liabilities [(d)]			$ 191	$ 1,983	$ 117	$ 1,927

(a) Prior period amounts have been restated to conform with current year presentation.
(b) Includes the revaluation of recoverable/regulated plant accumulated deferred income taxes and revaluation impact of non-plant accumulated deferred income taxes due to the TCJA.
(c) Includes the fair value of FTR instruments utilized/intended to offset the impacts of transmission system congestion.
(d) Revenue subject to refund of $67 million and $15 million for 2022 and 2021, respectively, is included in other current liabilities.

NSP-Minnesota's regulatory assets not earning a return include the unfunded portion of pension and retiree medical obligations and net AROs (i.e. deferrals for which cash has not been disbursed). In addition, regulatory assets included $369 million and $691 million, respectively, of past expenditures not earning a return. Amounts are predominately related to purchased natural gas and electric energy costs (including certain costs related to Winter Storm Uri), sales true-up and revenue decoupling, various renewable resources/environmental initiatives and certain prepaid pension amounts.

5. Borrowings and Other Financing Instruments

Short-Term Borrowings

NSP-Minnesota meets its short-term liquidity requirements primarily through the issuance of commercial paper and borrowings under its credit facility and the money pool.

Money Pool — Xcel Energy Inc. and its utility subsidiaries have established a money pool arrangement that allows for short-term investments in and borrowings between the utility subsidiaries. Xcel Energy Inc. may make investments in the utility subsidiaries at market-based interest rates; however, the money pool arrangement does not allow the utility subsidiaries to make investments in Xcel Energy Inc.

Money pool borrowings:

(Millions of Dollars, Except Interest Rates)	Three Months Ended Dec. 31, 2022	Year Ended Dec. 31 2022	2021	2020
Borrowing limit	$ 250	$ 250	$ 250	$ 250
Amount outstanding at period end	—	—	—	—
Average amount outstanding	—	—	6	3
Maximum amount outstanding	4	4	236	116
Weighted average interest rate, computed on a daily basis	3.87 %	3.87 %	0.07 %	1.53 %
Weighted average interest rate at period end	N/A	N/A	N/A	N/A

Commercial Paper — Commercial paper outstanding:

(Millions of Dollars, Except Interest Rates)	Three Months Ended Dec. 31, 2022	Year Ended Dec. 31 2022	2021	2020
Borrowing limit	$ 700	$ 700	$ 500	$ 500
Amount outstanding at period end	207	207	—	179
Average amount outstanding	81	21	26	10
Maximum amount outstanding	290	290	317	179
Weighted average interest rate, computed on a daily basis	4.32 %	4.14 %	0.18 %	1.25 %
Weighted average interest rate at end of period	4.64	4.64	N/A	0.18

Letters of Credit — NSP-Minnesota uses letters of credit, typically with terms of one year, to provide financial guarantees for certain operating obligations. At Dec. 31, 2022 and 2021, there were $15 million and $9 million of letters of credit outstanding under the credit facility, respectively. The contract amounts of these letters of credit approximate their fair value and are subject to fees.

Credit Facility — In order to use commercial paper programs to fulfill short-term funding needs, NSP-Minnesota must have revolving credit facilities in place at least equal to the amount of their respective commercial paper borrowing limits and cannot issue commercial paper exceeding available capacity under these credit facilities.

The lines of credit provide short-term financing in the form of notes payable to banks, letters of credit and back-up support for commercial paper borrowings.

Features of NSP-Minnesota's credit facility:

Debt-to-Total Capitalization Ratio [(a)] 2022	2021	Amount Facility May Be Increased (millions of dollars)	Additional Periods for Which a One-Year Extension May Be Requested [(b)]
48 %	47 %	$ 150	2

(a) The credit facility has a financial covenant requiring that the debt-to-total capitalization ratio be less than or equal to 65%.
(b) All extension requests are subject to majority bank group approval.

The credit facility has a cross-default provision that NSP-Minnesota would be in default on its borrowings under the facility if it or any of its subsidiaries whose total assets exceed 15% of NSP-Minnesota's consolidated total assets, default on indebtedness in an aggregate principal amount exceeding $75 million.

If NSP-Minnesota does not comply with the covenant, an event of default may be declared, and if not remedied, any outstanding amounts due under the facility can be declared due by the lender. As of Dec. 31, 2022, NSP-Minnesota was in compliance with all financial covenants on its debt agreements.

NSP-Minnesota had the following committed credit facility available as of Dec. 31, 2022 (in millions of dollars):

Credit Facility [(a)]	Drawn [(b)]	Available
$ 700	$ 222	$ 478

(a) This credit facility matures in September 2027.
(b) Includes outstanding commercial paper and letters of credit.

All credit facility bank borrowings, outstanding letters of credit and outstanding commercial paper reduce the available capacity under the credit facility. NSP-Minnesota had no direct advances on the facility outstanding at Dec. 31, 2022 and 2021.

Bilateral Credit Agreement — In April 2022, NSP-Minnesota's uncommitted bilateral credit agreement was renewed for an additional one-year term. The credit agreement is limited in use to support letters of credit.

As of Dec. 31, 2022, NSP-Minnesota had $54 million outstanding letters of credit under the $75 million Bilateral Credit Agreement.

Long-Term Borrowings and Other Financing Instruments

Generally, the property of NSP-Minnesota is subject to the lien of its first mortgage indenture for the benefit of bondholders. Debt premiums, discounts and expenses are amortized over the life of the related debt. The premiums, discounts and expenses for refinanced debt are deferred and amortized over the life of the new issuance.

Long term debt obligations for NSP-Minnesota as of Dec. 31 (in millions of dollars):

Financing Instrument	Interest Rate	Maturity Date	2022	2021
First mortgage bonds	2.15 %	Aug. 15, 2022	$ —	$ 300
First mortgage bonds	2.60	May 15, 2023	400	400
First mortgage bonds	7.125	July 1, 2025	250	250
First mortgage bonds	6.50	March 1, 2028	150	150
First mortgage bonds [a]	2.25	April 1, 2031	425	425
First mortgage bonds	5.25	July 15, 2035	250	250
First mortgage bonds	6.25	June 1, 2036	400	400
First mortgage bonds	6.20	July 1, 2037	350	350
First mortgage bonds	5.35	Nov. 1, 2039	300	300
First mortgage bonds	4.85	Aug. 15, 2040	250	250
First mortgage bonds	3.40	Aug. 15, 2042	500	500
First mortgage bonds	4.125	May 15, 2044	300	300
First mortgage bonds	4.00	Aug. 15, 2045	300	300
First mortgage bonds	3.60	May 15, 2046	350	350
First mortgage bonds	2.90	March 1, 2050	600	600
First mortgage bonds	2.60	June 1, 2051	700	700
First mortgage bonds [a]	3.20	April 1, 2052	425	425
First mortgage bonds [b]	4.50	June 1,2052	500	—
Other long-term debt			3	3
Unamortized discount			(45)	(44)
Unamortized debt issuance cost			(66)	(62)
Current maturities			(400)	(300)
Total long-term debt			$ 6,542	$ 6,447

[a] 2021 financing.
[b] 2022 financing.

Maturities of long-term debt are as follows:

(Millions of Dollars)	
2023	$ 400
2024	—
2025	250
2026	—
2027	—

Deferred Financing Costs — Deferred financing costs of approximately $66 million and $62 million, net of amortization, are presented as a deduction from the carrying amount of long-term debt at Dec. 31, 2022 and 2021, respectively.

Dividend Restrictions — NSP-Minnesota's dividends are subject to the FERC's jurisdiction, which prohibits the payment of dividends out of capital accounts. Dividend payments are solely to be paid from retained earnings.

NSP-Minnesota's state regulatory commissions additionally impose dividend limitations, which are more restrictive than those imposed by the FERC.

Requirements and actuals as of Dec. 31, 2022:

Equity to Total Capitalization Ratio Required Range		Equity to Total Capitalization Ratio Actual
Low	High	2022
47.2 %	57.6 %	52.3 %

Unrestricted Retained Earnings	Total Capitalization	Limit on Total Capitalization
$ 1,446 million	$ 14,984 million	$ 16,140 million

6. Revenues

Revenue is classified by the type of goods/services rendered and market/customer type. NSP-Minnesota's operating revenues consisted of the following:

	Year Ended Dec. 31, 2022			
(Millions of Dollars)	Electric	Natural Gas	All Other	Total
Major revenue types				
Revenue from contracts with customers:				
Residential	$ 1,463	$ 510	$ 38	$ 2,011
C&I	2,376	433	—	2,809
Other	38	—	7	45
Total retail	3,877	943	45	4,865
Wholesale	668	—	—	668
Transmission	287	—	—	287
Interchange	514	—	—	514
Other	15	19	—	34
Total revenue from contracts with customers	5,361	962	45	6,368
Alternative revenue and other	256	60	—	316
Total revenues	$ 5,617	$ 1,022	$ 45	$ 6,684

	Year Ended Dec. 31, 2021			
(Millions of Dollars)	Electric	Natural Gas	All Other	Total
Major revenue types				
Revenue from contracts with customers:				
Residential	$ 1,374	$ 315	$ 33	$ 1,722
C&I	2,107	246	—	2,353
Other	33	—	6	39
Total retail	3,514	561	39	4,114
Wholesale	442	—	—	442
Transmission	242	—	—	242
Interchange	501	—	—	501
Other	7	14	—	21
Total revenue from contracts with customers	4,706	575	39	5,320
Alternative revenue and other	388	48	—	436
Total revenues	$ 5,094	$ 623	$ 39	$ 5,756

(Millions of Dollars)	Year Ended Dec. 31, 2020 Electric	Natural Gas	All Other	Total
Major revenue types				
Revenue from contracts with customers:				
Residential	$ 1,375	$ 261	$ 31	$ 1,667
C&I	1,935	189	—	2,124
Other	33	—	6	39
Total retail	3,343	450	37	3,830
Wholesale	202	—	—	202
Transmission	238	—	—	238
Interchange	440	—	—	440
Other	15	7	—	22
Total revenue from contracts with customers	4,238	457	37	4,732
Alternative revenue and other	333	36	—	369
Total revenues	$ 4,571	$ 493	$ 37	$ 5,101

7. Income Taxes

Total income tax expense from operations differs from the amount computed by applying the statutory federal income tax rate to income before income tax expense.

Effective income tax rate for years ended Dec. 31:

	2022	2021 [(c)]	2020 [(c)]
Federal statutory rate	21.0 %	21.0 %	21.0 %
State income tax on pretax income, net of federal tax effect	7.0	7.0	7.0
Increases (decreases) in tax from:			
Wind PTCs [(a)]	(39.6)	(27.8)	(19.3)
Plant regulatory differences [(b)]	(6.7)	(8.1)	(7.2)
Other tax credits, net NOL & tax credit allowances	(1.3)	(1.4)	(1.2)
NOL Carryback	—	—	(2.1)
Other, net	(0.3)	0.7	0.8
Effective income tax rate	(19.9)%	(8.6)%	(1.0)%

(a) Wind PTCs are credited to customers (reduction to revenue) and do not materially impact net income.

(b) Regulatory differences for income tax primarily relate to the credit of excess deferred taxes to customers through the average rate assumption method. Income tax benefits associated with the credit of excess deferred taxes are offset by corresponding revenue reductions.

(c) Prior period amounts have been restated to conform with current year presentation.

Components of income tax expense for years ended Dec. 31:

(Millions of Dollars)	2022	2021	2020
Current federal tax expense (benefit)	$ 70	$ (10)	$ 41
Current state tax expense (benefit)	26	(1)	12
Current change in unrecognized tax expense	8	1	9
Deferred federal tax benefit	(237)	(87)	(102)
Deferred state tax expense	23	49	38
Deferred change in unrecognized tax expense (benefit)	—	2	(3)
Deferred ITCs	(2)	(2)	(1)
Total income tax benefit	$ (112)	$ (48)	$ (6)

Components of deferred income tax expense as of Dec. 31:

(Millions of Dollars)	2022	2021	2020
Deferred tax (benefit) expense excluding items below	$ (283)	$ 109	61
Amortization and adjustments to deferred income taxes on income tax regulatory assets and liabilities	70	(145)	(127)
Tax expense allocated to other comprehensive income, and other	(1)	—	(1)
Deferred tax benefit	$ (214)	$ (36)	$ (67)

Components of the net deferred tax liability as of Dec. 31:

(Millions of Dollars)	2022	2021 [(a)]
Deferred tax liabilities:		
Differences between book and tax bases of property	$ 2,708	$ 2,679
Regulatory assets	189	214
Deferred fuel costs	49	92
Pension expense	68	73
Other	10	13
Total deferred tax liabilities	$ 3,122	$ 3,194
Deferred tax assets:		
Tax credit carryforward	$ 977	$ 782
Regulatory Liabilities	325	279
Operating lease liabilities	98	123
NOL and tax credit valuation allowances	(58)	(64)
Other employee benefits	27	32
NOL carryforward	15	43
Deferred ITCs	5	5
Rate refund	28	11
Other	39	34
Total deferred tax assets	$ 1,456	$ 1,245
Net deferred tax liability	$ 1,666	$ 1,949

(a) Prior periods have been reclassified to conform to current year presentation.

Other Income Tax Matters — NOL amounts represent the tax loss that is carried forward and tax credits represent the deferred tax asset. NOL and tax credit carryforwards as of Dec. 31 were as follows:

(Millions of Dollars)	2022	2021
Federal NOL carryforward	$ 2	$ 77
Federal tax credit carryforwards	909	704
State NOL carryforwards	184	344
Valuation allowances for state NOL carryforwards	(1)	(1)
State tax credit carryforwards, net of federal detriment [(a)]	68	78
Valuation allowances for state credit carryforwards, net of federal benefit [(b)]	(58)	(64)

(a) State tax credit carryforwards are net of federal detriment of $18 million and $21 million as of Dec. 31, 2022 and 2021, respectively.

(b) Valuation allowances for state tax credit carryforwards were net of federal benefit of $15 million and $17 million as of Dec. 31, 2022 and 2021, respectively.

Federal carryforward periods expire starting 2032 and state carryforward periods expire starting 2022.

Federal Tax Loss Carryback Claims — In 2020, Xcel Energy identified certain expenses related to tax years 2009 - 2011 that qualify for an extended carryback claim. As a result, a tax benefit of approximately $13 million was recognized in 2020.

Unrecognized Tax Benefits

Federal Audit — NSP-Minnesota is a member of the Xcel Energy affiliated group that files a consolidated federal income tax return. Statute of limitations applicable to Xcel Energy's consolidated federal income tax returns expire as follows:

Tax Year(s)	Expiration
2014 - 2016	March 2024
2019	October 2023

Additionally, the statute of limitations related to the federal tax credit carryforwards will remain open until those credits are utilized in subsequent returns. Further, the statute of limitations related to the additional federal tax loss carryback claim filed in 2020 has been extended. Xcel Energy has recognized its best estimate of income tax expense that will result from a final resolution of this issue; however, the outcome and timing of a resolution is unknown.

State Audits — NSP-Minnesota is a member of the Xcel Energy affiliated group that files consolidated state income tax returns. As of Dec. 31, 2022, NSP-Minnesota's earliest open tax years subject to examination by state taxing authorities under applicable statutes of limitations are as follows:

State	Tax Year(s)	Expiration
Minnesota	2014-2016	September 2024
Minnesota	2018	June 2023

In 2020, Minnesota began an audit of tax years 2015-2018. In 2022, the state of Minnesota issued its audit report without any material adjustments.

Unrecognized Tax Benefits — Unrecognized tax benefit balance includes permanent tax positions, which if recognized would affect the ETR. In addition, the unrecognized tax benefit balance includes temporary tax positions for which deductibility is highly certain, but for which there is uncertainty about the timing. A change in the timing of deductibility would not affect the ETR but would accelerate the payment to the taxing authority.

Unrecognized tax benefits - permanent vs temporary:

(Millions of Dollars)	Dec. 31, 2022	Dec. 31, 2021
Unrecognized tax benefit — Permanent tax positions	$ 31	$ 23
Unrecognized tax benefit — Temporary tax positions	3	3
Total unrecognized tax benefit	$ 34	$ 26

Changes in unrecognized tax benefits:

(Millions of Dollars)	2022	2021	2020
Balance at Jan. 1	$ 26	$ 24	$ 20
Additions based on tax positions related to the current year	2	2	2
Reductions based on tax positions related to the current year	—	—	—
Additions for tax positions of prior years	6	—	16
Reductions for tax positions of prior years	—	—	(14)
Balance at Dec. 31	$ 34	$ 26	$ 24

Unrecognized tax benefits were reduced by tax benefits associated with NOL and tax credit carryforwards:

(Millions of Dollars)	Dec. 31, 2022	Dec. 31, 2021
NOL and tax credit carryforwards	$ (13)	$ (13)

As the IRS progresses its review of the tax loss carryback claims and as state audits progress, it is reasonably possible that the amount of unrecognized tax benefit could decrease up to approximately $22 million in the next 12 months.

Payable for interest related to unrecognized tax benefits is partially offset by the interest benefit associated with NOL and tax credit carryforwards.

Interest payable related to unrecognized tax benefits:

(Millions of Dollars)	2022	2021	2020
Payable for interest related to unrecognized tax benefits at Jan. 1	$ (2)	$ (2)	$ (2)
Interest expense related to unrecognized tax benefits	(1)	—	—
Payable for interest related to unrecognized tax benefits at Dec. 31	$ (3)	$ (2)	$ (2)

No amounts were accrued for penalties related to unrecognized tax benefits as of Dec. 31, 2022, 2021 or 2020.

8. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

Accounting guidance for fair value measurements and disclosures provides a hierarchical framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value.

- Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. The types of assets and liabilities included in Level 1 are actively traded instruments with observable actual trading prices.
- Level 2 — Pricing inputs are other than actual trading prices in active markets, but are either directly or indirectly observable as of the reporting date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts, or priced with models using highly observable inputs.
- Level 3 — Significant inputs to pricing have little or no observability as of the reporting date. The types of assets and liabilities included in Level 3 include those valued with models requiring significant judgment or estimation.

Specific valuation methods include:

Investments in equity securities and other funds — Equity securities are valued using quoted prices in active markets. The fair values for commingled funds are measured using NAVs. The investments in commingled funds may be redeemed for NAV with proper notice. Private equity commingled funds require approval of the fund for any unscheduled redemption, and such redemptions may be approved or denied by the fund at its sole discretion. Unscheduled distributions from real estate commingled funds may be redeemed with proper notice, however, withdrawals may be delayed or discounted as a result of fund illiquidity.

Investments in debt securities — Fair values for debt securities are determined by a third party pricing service using recent trades and observable spreads from benchmark interest rates for similar securities.

Interest rate derivatives — Fair values of interest rate derivatives are based on broker quotes that utilize current market interest rate forecasts.

Commodity derivatives — Methods used to measure the fair value of commodity derivative forwards and options utilize forward prices and volatilities, as well as pricing adjustments for specific delivery locations, and are generally assigned a Level 2 classification. When contracts relate to inactive delivery locations or extend to periods beyond those readily observable on active exchanges, the significance of the use of less observable inputs on a valuation is evaluated and may result in Level 3 classification.

Electric commodity derivatives held by NSP-Minnesota include transmission congestion instruments, generally referred to as FTRs. FTRs purchased from an RTO are financial instruments that entitle or obligate the holder to monthly revenues or charges based on transmission congestion across a given transmission path.

The values of these instruments are derived from, and designed to offset, the costs of transmission congestion. In addition to overall transmission load, congestion is also influenced by the operating schedules of power plants and the consumption of electricity pertinent to a given transmission path. Unplanned plant outages, scheduled plant maintenance, changes in the relative costs of fuels used in generation, weather and overall changes in demand for electricity can each impact the operating schedules of the power plants on the transmission grid and the value of these instruments. FTRs are recognized at fair value and adjusted each period prior to settlement. Given the limited observability of certain variables underlying the reported auction values of FTRs, these fair value measurements have been assigned a Level 3 classification.

Net congestion costs, including the impact of FTR settlements are shared through fuel and purchased energy cost recovery mechanisms. As such, the fair value of the unsettled instruments (i.e., derivative asset or liability) is offset/deferred as a regulatory asset or liability.

Non-Derivative Fair Value Measurements

Nuclear Decommissioning Fund

The NRC requires NSP-Minnesota to maintain a portfolio of investments to fund the costs of decommissioning its nuclear generating plants. Assets of the nuclear decommissioning fund are legally restricted for the purpose of decommissioning these facilities. The fund contains cash equivalents, debt securities, equity securities and other investments. NSP-Minnesota uses the MPUC approved asset allocation for the investment targets by asset class for the qualified trust.

NSP-Minnesota recognizes the costs of funding the decommissioning over the lives of the nuclear plants, assuming rate recovery of all costs. Realized and unrealized gains on fund investments over the life of the fund are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs. Consequently, any realized and unrealized gains and losses on securities in the nuclear decommissioning fund are deferred as a component of the regulatory asset.

Unrealized gains for the nuclear decommissioning fund were $1 billion and $1.3 billion as of Dec. 31, 2022 and 2021, respectively, and unrealized losses were $90 million and $7 million as of Dec. 31, 2022 and 2021, respectively.

Non-derivative instruments with recurring fair value measurements in the nuclear decommissioning fund:

	Dec. 31, 2022					
		Fair Value				
(Millions of Dollars)	**Cost**	**Level 1**	**Level 2**	**Level 3**	**NAV**	**Total**
Nuclear decommissioning fund [(a)]						
Cash equivalents	$ 29	$ 29	$ —	$ —	$ —	$ 29
Commingled funds	803	—	—	—	1,178	1,178
Debt securities	738	—	669	6	—	675
Equity securities	406	999	1	—	—	1,000
Total	$ 1,976	$ 1,028	$ 670	$ 6	$ 1,178	$ 2,882

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheets, which also includes $48 million of rabbi trust assets and other miscellaneous investments.

	Dec. 31, 2021					
		Fair Value				
(Millions of Dollars)	**Cost**	**Level 1**	**Level 2**	**Level 3**	**NAV**	**Total**
Nuclear decommissioning fund [(a)]						
Cash equivalents	$ 64	$ 64	$ —	$ —	$ —	$ 64
Commingled funds	856	—	—	—	1,294	1,294
Debt securities	631	—	666	9	—	675
Equity securities	411	1,222	1	—	—	1,223
Total	$ 1,962	$ 1,286	$ 667	$ 9	$ 1,294	$ 3,256

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheets, which also includes $52 million of rabbi trust assets and other miscellaneous investments.

For the years ended Dec. 31, 2022 and 2021, there were immaterial Level 3 nuclear decommissioning fund investments or transfer of amounts between levels.

Contractual maturity dates of debt securities in the nuclear decommissioning fund as of Dec. 31, 2022:

	Final Contractual Maturity				
(Millions of Dollars)	**Due in 1 Year or Less**	**Due in 1 to 5 Years**	**Due in 5 to 10 Years**	**Due after 10 Years**	**Total**
Debt securities	$ 6	$ 204	$ 250	$ 216	$ 676

Rabbi Trusts

NSP-Minnesota has established a rabbi trust to provide partial funding for future distributions of its deferred compensation plan. The fair value of assets held in the rabbi trusts were $12 million and $13 million at Dec. 31, 2022 and 2021, respectively, comprised of cash equivalents and mutual funds (level 1 valuation methods). Amounts are reported in nuclear decommissioning fund and other investments on the consolidated balance sheet.

Derivative Activities and Fair Value Measurements

NSP-Minnesota enters into derivative instruments, including forward contracts, futures, swaps and options, for trading purposes and to manage risk in connection with changes in interest rates and utility commodity prices.

Interest Rate Derivatives — NSP-Minnesota enters into contracts that effectively fix the interest rate on a specified principal amount of a hypothetical future debt issuance. These financial swaps net settle based on changes in a specified benchmark interest rate, acting as a hedge of changes in market interest rates that will impact specified anticipated debt issuances. These derivative instruments are designated as cash flow hedges for accounting purposes, with changes in fair value prior to occurrence of the hedged transactions recorded as other comprehensive income.

As of Dec. 31, 2022, accumulated other comprehensive loss related to interest rate derivatives included $1 million of net losses expected to be reclassified into earnings during the next 12 months as the hedged transactions impact earnings. As of Dec. 31, 2022, NSP-Minnesota had no unsettled interest rate derivatives.

For the financial impact of qualifying interest rate cash flow hedges on NSP-Minnesota's accumulated other comprehensive loss included in the consolidated statements of common stockholder's equity and in the consolidated statements of comprehensive income, see Note 11.

Wholesale and Commodity Trading — NSP-Minnesota conducts various wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy, energy-related instruments and natural gas-related instruments, including derivatives. NSP-Minnesota is allowed to conduct these activities within guidelines and limitations as approved by its risk management committee, comprised of management personnel not directly involved in the activities governed by this policy.

Derivative instruments entered into for trading purposes are presented in the consolidated statements of income as electric revenues, net of any sharing with customers. These activities are not intended to mitigate commodity price risk associated with regulated electric and natural gas operations. Sharing of these margins is determined through state regulatory proceedings as well as the operation of the FERC-approved joint operating agreement.

Commodity Derivatives — NSP-Minnesota enters into derivative instruments to manage variability of future cash flows from changes in commodity prices in its electric and natural gas operations. This could include the purchase or sale of energy or energy-related products, natural gas to generate electric energy, natural gas for resale and FTRs.

The most significant derivative positions outstanding at December 31, 2022 and 2021 for this purpose relate to FTR instruments administered by MISO. These instruments are intended to offset the impacts of transmission system congestion. Higher congestion costs in recent years have led to an increase in the fair value of FTRs. Settlements of FTRs are shared with electric customers through fuel and purchased energy cost-recovery mechanisms.

When NSP-Minnesota enters into derivative instruments that mitigate commodity price risk on behalf of electric and natural gas customers, the instruments are not typically designated as qualifying hedging transactions. The classification of unrealized losses or gains on these instruments as a regulatory asset or liability, if applicable, is based on approved regulatory recovery mechanisms. As of Dec. 31, 2022, NSP-Minnesota had no commodity contracts designated as cash flow hedges.

Gross notional amounts of commodity forwards, options and FTRs:

(Amounts in Millions) [a][b]	Dec. 31, 2022	Dec. 31, 2021
MWh of electricity	44	57
MMBtu of natural gas	88	85

(a) Not reflective of net positions in the underlying commodities.
(b) Notional amounts for options included on a gross basis, but are weighted for the probability of exercise.

Consideration of Credit Risk and Concentrations — NSP-Minnesota continuously monitors the creditworthiness of counterparties to its interest rate derivatives and commodity derivative contracts prior to settlement and assesses each counterparty's ability to perform on the transactions set forth in the contracts. Impact of credit risk was immaterial to the fair value of unsettled commodity derivatives presented on the consolidated balance sheets. NSP-Minnesota's most significant concentrations of credit risk with particular entities or industries are contracts with counterparties to its wholesale, trading and non-trading commodity activities.

As of Dec. 31, 2022, six of NSP-Minnesota's ten most significant counterparties for these activities, comprising $38 million or 34% of this credit exposure, had investment grade credit ratings from S&P Global Ratings, Moody's Investor Services or Fitch Ratings.

Three of the ten most significant counterparties, comprising $28 million or 25% of this credit exposure, were not rated by these external ratings agencies, but based on NSP-Minnesota's internal analysis, had credit quality consistent with investment grade. One of these significant counterparties, comprising $47 million or 41% of this credit exposure, had credit quality less than investment grade, based on internal analysis. Four of these significant counterparties are municipal or cooperative electric entities, RTOs or other utilities.

Credit Related Contingent Features — Contract provisions for derivative instruments that the utility subsidiaries enter, including those accounted for as normal purchase and normal sale contracts and therefore not reflected on the consolidated balance sheets, may require the posting of collateral or settlement of the contracts for various reasons, including if the applicable utility subsidiary's credit ratings are downgraded below its investment grade credit rating by any of the major credit rating agencies. As of Dec. 31, 2022 and 2021, there were $4 million and $3 million, respectively, of derivative liabilities with such underlying contract provisions, respectively.

Certain contracts also contain cross default provisions that may require the posting of collateral or settlement of the contracts if there was a failure under other financing arrangements related to payment terms or other covenants.

As of Dec. 31, 2022 and 2021, there were approximately $76 million and $48 million of derivative liabilities with such underlying contract provisions, respectively.

Certain derivative instruments are also subject to contract provisions that contain adequate assurance clauses. These provisions allow counterparties to seek performance assurance, including cash collateral, in the event that a given utility subsidiary's ability to fulfill its contractual obligations is reasonably expected to be impaired. Xcel Energy had no collateral posted related to adequate assurance clauses in derivative contracts as of Dec. 31, 2022 and 2021.

Recurring Derivative Fair Value Measurements

Impact of derivative activity:

	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in:	
(Millions of Dollars)	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities
Year Ended Dec. 31, 2022		
Other derivative instruments		
Electric commodity	$ —	$ (7)
Natural gas commodity	—	—
Total	$ —	$ (7)
Year Ended Dec. 31, 2021		
Other derivative instruments		
Electric commodity	$ —	$ 3
Natural gas commodity	—	(3)
Total	$ —	$ —
Year Ended Dec. 31, 2020		
Other derivative instruments		
Electric commodity	$ —	$ 2
Natural gas commodity	—	(2)
Total	$ —	$ —

(Millions of Dollars)	Pre-Tax (Gains) Losses Reclassified into Income During the Period from: Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	Pre-Tax Gains (Losses) Recognized During the Period in Income
Year Ended Dec. 31, 2022			
Derivatives designated as cash flow hedges			
Interest rate	$ 1 [(a)]	$ —	$ —
Total	$ 1	$ —	$ —
Other derivative instruments			
Commodity trading	$ —	$ —	$ 17 [(b)]
Electric commodity	—	1 [(c)]	—
Natural gas commodity	—	2 [(d)]	(8) [(d)(e)]
Total	$ —	$ 3	$ 9
Year Ended Dec. 31, 2021			
Derivatives designated as cash flow hedges			
Interest rate	$ 2 [(a)]	$ —	$ —
Total	$ 2	$ —	$ —
Other derivative instruments			
Commodity trading	$ —	$ —	$ 51 [(b)]
Electric commodity	—	(3) [(c)]	—
Natural gas commodity	—	1 [(d)]	(6) [(d)(e)]
Total	$ —	$ (2)	$ 45
Year Ended Dec. 31, 2020			
Derivatives designated as cash flow hedges			
Interest rate	$ 1 [(a)]	$ —	$ —
Total	$ 1	$ —	$ —
Other derivative instruments			
Commodity trading	$ —	$ —	$ (5) [(b)]
Electric commodity	$ —	$ (3) [(c)]	$ —
Natural gas commodity	—	2 [(d)]	(4) [(d)(e)]
Total	$ —	$ (1)	$ (9)

(a) Recorded to interest charges.
(b) Recorded to electric revenues. Presented amounts do not reflect non-derivative transactions or margin sharing with customers.
(c) Recorded to electric fuel and purchased power. These derivative settlement gains and losses are shared with electric customers through fuel and purchased energy cost-recovery mechanisms and reclassified out of income as regulatory assets or liabilities, as appropriate. FTR settlements are shared with customers and do not have a material impact on net income. Presented amounts reflect changes in fair value between auction and settlement dates, but exclude the original auction fair value.
(d) Recorded to cost of natural gas sold and transported. These losses are subject to cost-recovery mechanisms and reclassified out of income to a regulatory asset, as appropriate.
(e) Relates primarily to option premium amortization.

NSP-Minnesota had no derivative instruments designated as fair value hedges during the years ended Dec. 31, 2022, 2021 and 2020.

Derivative assets and liabilities measured at fair value on a recurring basis were as follows:

	Dec. 31, 2022						Dec. 31, 2021					
	Fair Value						Fair Value					
(Millions of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Netting [(a)]	Total	Level 1	Level 2	Level 3	Fair Value Total	Netting [(a)]	Total
Current derivative assets												
Other derivative instruments:												
Commodity trading	$ 15	$ 38	$ 33	$ 86	$ (58)	$ 28	$ 9	$ 40	$ 22	$ 71	$ (53)	$ 18
Electric commodity	—	—	58	58	(2)	56	—	—	30	30	(1)	29
Natural gas commodity	—	5	—	5	—	5	—	6	—	6	—	6
Total current derivative assets	$ 15	$ 43	$ 91	$ 149	$ (60)	$ 89	$ 9	$ 46	$ 52	$ 107	$ (54)	$ 53
Noncurrent derivative assets												
Other derivative instruments:												
Commodity trading	$ 21	$ 40	$ 66	$ 127	$ (59)	$ 68	$ 6	$ 34	$ 35	$ 75	$ (42)	$ 33
Total noncurrent derivative assets	$ 21	$ 40	$ 66	$ 127	$ (59)	$ 68	$ 6	$ 34	$ 35	$ 75	$ (42)	$ 33

	Dec. 31, 2022						Dec. 31, 2021					
	Fair Value						Fair Value					
(Millions of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Netting [(a)]	Total	Level 1	Level 2	Level 3	Fair Value Total	Netting [(a)]	Total
Current derivative liabilities												
Other derivative instruments:												
Commodity trading	$ 23	$ 60	$ 6	$ 89	$ (63)	$ 26	$ 13	$ 58	$ 4	$ 75	$ (58)	$ 17
Electric commodity	—	—	2	2	(2)	—	—	—	1	1	(1)	—
Natural gas commodity	—	2	—	2	—	2	—	4	—	4	—	4
Total current derivative liabilities	$ 23	$ 62	$ 8	$ 93	$ (65)	28	$ 13	$ 62	$ 5	$ 80	$ (59)	21
PPAs [(b)]						14						14
Current derivative instruments						$ 42						$ 35
Noncurrent derivative liabilities												
Other derivative instruments:												
Commodity trading	$ 37	$ 55	$ 42	$ 134	$ (60)	$ 74	$ 15	$ 48	$ 26	$ 89	$ (53)	$ 36
Total noncurrent derivative liabilities	$ 37	$ 55	$ 42	$ 134	$ (60)	74	$ 15	$ 48	$ 26	$ 89	$ (53)	36
PPAs [(b)]						28						35
Noncurrent derivative instruments						$ 102						$ 71

(a) NSP-Minnesota nets derivative instruments and related collateral on its consolidated balance sheets when supported by a legally enforceable master netting agreement. At Dec. 31, 2022 and 2021, derivative assets and liabilities include no obligations to return cash collateral. At Dec. 31, 2022 and 2021, derivative assets and liabilities include rights to reclaim cash collateral of $6 million and $16 million, respectively. Counterparty netting amounts presented exclude settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

(b) NSP-Minnesota currently applies the normal purchase exception to qualifying PPAs. Balance relates to specific contracts that were previously recognized at fair value prior to applying the normal purchase exception, and are being amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.

Changes in Level 3 commodity derivatives:

	Year Ended Dec. 31		
(Millions of Dollars)	2022	2021	2020
Balance at Jan. 1	$ 56	$ (11)	$ 5
Purchases [(a)]	157	54	28
Settlements [(a)]	(195)	(82)	(49)
Net transactions recorded during the period:			
Gains (losses) recognized in earnings [(b)]	91	72	(8)
Net gains (losses) recognized as regulatory assets and liabilities [(a)]	(2)	23	13
Balance at Dec. 31	$ 107	$ 56	$ (11)

(a) Relates primarily to FTR instruments administered by MISO.

(b) Relates to commodity trading and is subject to substantial offsetting losses and gains on derivative instruments categorized as levels 1 and 2 in the income statement. See above tables for the income statement impact of derivative activity, including commodity trading gains and losses.

Fair Value of Long-Term Debt

As of Dec. 31, other financial instruments for which the carrying amount did not equal fair value:

	2022		2021	
(Millions of Dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current portion	$ 6,942	$ 5,995	$ 6,747	$ 7,761

Fair value of NSP-Minnesota's long-term debt is estimated based on recent trades and observable spreads from benchmark interest rates for similar securities. Fair value estimates are based on information available to management as of Dec. 31, 2022 and 2021, and given the observability of the inputs, fair values presented for long-term debt were assigned as Level 2.

9. Benefit Plans and Other Postretirement Benefits

Pension and Postretirement Health Care Benefits

Xcel Energy, which includes NSP-Minnesota, has several noncontributory, qualified, defined benefit pension plans that cover almost all employees. All newly hired or rehired employees participate under the Cash Balance formula, which is based on pay credits using a percentage of annual eligible pay and annual interest credits. The average annual interest crediting rates for these plans was 4.86, 1.96 and 1.78% in 2022, 2021, and 2020, respectively. Some employees may participate under legacy formulas such as the traditional final average pay or pension equity. Xcel Energy's and NSP-Minnesota's policy is to fully fund into an external trust the actuarially determined pension costs subject to the limitations of applicable employee benefit and tax laws.

In addition to the qualified pension plans, Xcel Energy maintains a SERP and a nonqualified pension plan. The SERP is maintained for certain executives who participated in the plan in 2008, when the SERP was closed to new participants. The nonqualified pension plan provides benefits for compensation that is in excess of the limits applicable to the qualified pension plans, with distributions funded by Xcel Energy's consolidated operating cash flows. Obligations of the SERP and nonqualified plan as of Dec. 31, 2022 and 2021 were $11 million and $43 million, respectively, of which $2 million and $3 million was attributable to NSP-Minnesota in 2022 and 2021, respectively. Xcel Energy recognized net benefit cost for the SERP and nonqualified plans of $17 million in 2022 and $4 million in 2021, respectively, of which immaterial amounts were attributable to NSPM.

Investment-return assumption considers the expected long-term performance for each of the asset classes in its pension and postretirement health care portfolio. Xcel Energy considers the historical returns achieved by its asset portfolios over long time periods, as well as the long-term projected return levels from investment experts. Xcel Energy and NSP-Minnesota continually review their pension assumptions.

Pension cost determination assumes a forecasted mix of investment types over the long-term.

- Investment returns in 2022 were below the assumed level of 6.60%.
- Investment returns in 2021 were above the assumed level of 6.60%.
- Investment returns in 2020 were above the assumed level of 7.10%.
- In 2023, NSP-Minnesota's expected investment-return assumption is 7.25%.

Pension plan and postretirement benefit assets are invested in a portfolio according to Xcel Energy's return, liquidity and diversification objectives to provide a source of funding for plan obligations and minimize contributions to the plan, within appropriate levels of risk. The principal mechanism for achieving these objectives is the asset allocation given the long-term risk, return, correlation and liquidity characteristics of each particular asset class. There were no significant concentrations of risk in any industry, index, or entity. Market volatility can impact even well-diversified portfolios and significantly affect the return levels achieved by the assets in any year.

Xcel Energy's ongoing investment strategy is based on plan-specific investment recommendations that seek to minimize potential investment and interest rate risk as a plan's funded status increases over time. The investment recommendations consider many factors and generally result in a greater percentage of long-duration fixed income securities being allocated to specific plans having relatively higher funded status ratios and a greater percentage of growth assets being allocated to plans having relatively lower funded status ratios.

Plan Assets

For each of the fair value hierarchy levels, NSP-Minnesota's pension plan assets measured at fair value:

	Dec. 31, 2022 [(a)]					Dec. 31, 2021 [(a)]				
(Millions of Dollars)	Level 1	Level 2	Level 3	Measured at NAV	Total	Level 1	Level 2	Level 3	Measured at NAV	Total
Cash equivalents	$ 26	$ —	$ —	$ —	$ 26	$ 31	$ —	$ —	$ —	$ 31
Commingled funds	201	—	—	201	402	304	—	—	274	578
Debt securities	—	129	1	—	130	—	219	1	—	220
Equity securities	11	—	—	—	11	16	—	—	—	16
Other	—	1	—	—	1	—	1	—	7	8
Total	$ 238	$ 130	$ 1	$ 201	$ 570	$ 351	$ 220	$ 1	$ 281	$ 853

(a) See Note 8 for further information regarding fair value measurement inputs and methods.

For each of the fair value hierarchy levels, NSP-Minnesota's postretirement benefit plan assets that were measured at fair value:

	Dec. 31, 2022 [(a)]					Dec. 31, 2021 [(a)]				
(Millions of Dollars)	Level 1	Level 2	Level 3	Measured at NAV	Total	Level 1	Level 2	Level 3	Measured at NAV	Total
Insurance contracts	—	1	—	—	1	—	—	—	—	—
Commingled funds	$ 1	$ —	$ —	$ 1	$ 2	$ —	$ —	$ —	$ 1	$ 1
Debt securities	—	2	—	—	2	—	2	—	—	2
Total	$ 1	$ 3	$ —	$ 1	$ 5	$ —	$ 2	$ —	$ 1	$ 3

(a) See Note 8 for further information on fair value measurement inputs and methods.

No assets were transferred in or out of Level 3 for 2022 or 2021.

Funded Status — Benefit obligations for both pension and postretirement plans decreased from Dec. 31, 2021 to Dec. 31, 2022, due primarily to benefit payments and increases in discount rates used in actuarial valuations. Comparisons of the actuarially computed benefit obligation, changes in plan assets and funded status of the pension and postretirement health care plans for NSP-Minnesota are as follows:

	Pension Benefits		Postretirement Benefits	
(Millions of Dollars)	**2022**	**2021**	**2022**	**2021**
Change in Benefit Obligation:				
Obligation at Jan. 1	$ 877	$ 989	$ 64	$ 73
Service cost	27	30	—	—
Interest cost	25	25	2	2
Plan amendments	1	1	—	—
Actuarial gain	(139)	(28)	(13)	(5)
Benefit payments	(134)	(140)	(5)	(6)
Obligation at Dec. 31	$ 657	$ 877	$ 48	$ 64
Change in Fair Value of Plan Assets:				
Fair value of plan assets at Jan. 1	$ 853	$ 897	$ 3	$ 2
Actual return on plan assets	(154)	62	—	—
Employer contributions	5	34	7	7
Benefit payments	(134)	(140)	(5)	(6)
Fair value of plan assets at Dec. 31	$ 570	$ 853	$ 5	$ 3
Funded status of plans at Dec. 31	$ (87)	$ (24)	$ (43)	$ (61)
Amounts recognized in the Consolidated Balance Sheet at Dec. 31:				
Current liabilities	$ —	$ —	$ (1)	$ (3)
Noncurrent liabilities	(87)	(24)	(42)	(58)
Net amounts recognized	$ (87)	$ (24)	$ (43)	$ (61)

	Pension Benefits		Postretirement Benefits	
Significant Assumptions Used to Measure Benefit Obligations:	**2022**	**2021**	**2022**	**2021**
Discount rate for year-end valuation	5.80 %	3.08 %	5.80 %	3.09 %
Expected average long-term increase in compensation level	4.25	3.75	N/A	N/A
Mortality table	PRI-2012	PRI-2012	PRI-2012	PRI-2012
Health care costs trend rate — initial: Pre-65	N/A	N/A	6.50 %	5.30 %
Health care costs trend rate — initial: Post-65	N/A	N/A	5.50 %	4.90 %
Ultimate trend assumption — initial: Pre-65	N/A	N/A	4.50 %	4.50 %
Ultimate trend assumption — initial: Post-65	N/A	N/A	4.50 %	4.50 %
Years until ultimate trend is reached	N/A	N/A	7	4

Accumulated benefit obligation for the pension plan was $600 million and $811 million as of Dec. 31, 2022 and 2021, respectively.

Net Periodic Benefit Cost (Credit) — Net periodic benefit cost (credit), other than the service cost component, is included in other income (expense) in the consolidated statements of income.

Components of net periodic benefit cost (credit) and amounts recognized in other comprehensive income and regulatory assets and liabilities:

	Pension Benefits			Postretirement Benefits		
(Millions of Dollars)	**2022**	**2021**	**2020**	**2022**	**2021**	**2020**
Service cost	$ 27	$ 30	$ 27	$ —	$ —	$ —
Interest cost	25	25	31	2	2	2
Expected return on plan assets	(48)	(52)	(55)	—	—	—
Amortization of prior service cost	—	—	—	(3)	(3)	(3)
Amortization of net loss	24	34	33	1	2	1
Settlement charge [(a)]	38	35	—	—	—	—
Net periodic pension cost	66	72	36	—	1	—
Effects of regulation	(32)	(44)	(4)	—	—	—
Net benefit cost recognized for financial reporting	$ 34	$ 28	$ 32	$ —	$ 1	$ —
Significant Assumptions Used to Measure Costs:						
Discount rate	3.08 %	2.71 %	3.49 %	3.09 %	2.65 %	3.47 %
Expected average long-term increase in compensation level	3.75	3.75	3.75	—	—	—
Expected average long-term rate of return on assets	6.60	6.60	7.10	4.10	4.10	4.50

(a) A settlement charge is required when the amount of lump-sum distributions during the year is greater than the sum of the service and interest cost components of the annual net periodic pension cost. In 2022 and 2021, as a result of lump-sum distributions during each plan year, NSP-Minnesota recorded a total pension settlement charge of $38 million and $35 million, respectively, which was not recognized in earnings due to the effects of regulation. There were no settlement charges recorded for the qualified pension plans in 2020.

	Pension Benefits		Postretirement Benefits	
(Millions of Dollars)	**2022**	**2021**	**2022**	**2021**
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:				
Net loss	$ 309	$ 307	$ 16	$ 31
Prior service credit	—	—	(1)	(4)
Total	$ 309	$ 307	$ 15	$ 27
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost Have Been Recorded as Follows Based Upon Expected Recovery in Rates:				
Current regulatory assets	$ 12	$ 25	$ —	$ —
Noncurrent regulatory assets	297	282	14	25
Deferred income taxes	—	—	—	1
Net-of-tax accumulated other comprehensive income	—	—	1	1
Total	$ 309	$ 307	$ 15	$ 27
Measurement date	Dec 31, 2022	Dec 31, 2021	Dec 31, 2022	Dec 31, 2021

Cash Flows — Funding requirements can be impacted by changes to actuarial assumptions, actual asset levels and other calculations prescribed by the requirements of income tax and other pension-related regulations. Required contributions were made in 2020 - 2023 to meet minimum funding requirements.

Total voluntary and required pension funding contributions across all four of Xcel Energy's pension plans were as follows:

- $50 million in January 2023, of which $23 million is attributable to NSP-Minnesota.
- $50 million in 2022, of which $5 million was attributable to NSP-Minnesota.
- $131 million in 2021, of which $34 million was attributable to NSP-Minnesota.
- $150 million in 2020, of which $44 million was attributable to NSP-Minnesota.

The postretirement health care plans have no funding requirements other than fulfilling benefit payment obligations when claims are presented and approved. Additional cash funding requirements are prescribed by certain state and federal rate regulatory authorities. Xcel Energy's voluntary postretirement funding contributions were as follows:

- $12 million expected in 2023, of which $6 million is attributable to NSP-Minnesota.
- $13 million during 2022, of which $7 million, was attributable to NSP-Minnesota.
- $15 million during 2021, of which $8 million was attributable to NSP-Minnesota.
- $11 million during 2020, of which $6 million was attributable to NSP-Minnesota.

Targeted asset allocations:

	Pension Benefits		Postretirement Benefits	
	2022	2021	2022	2021
Domestic and international equity securities	33 %	33 %	16 %	15 %
Long-duration fixed income and interest rate swap securities	38	37	—	—
Short-to-intermediate fixed income securities	9	11	71	71
Alternative investments	18	17	12	8
Cash	2	2	1	6
Total	100 %	100 %	100 %	100 %

The asset allocations above reflect target allocations approved in the calendar year to take effect in the subsequent year

Plan Amendments — In 2022 and 2020, there were no significant plan amendments made which affected the postretirement benefit obligation.

In 2021, Xcel Energy amended the Xcel Energy Pension Plan and Xcel Energy Inc. Nonbargaining Pension Plan (South) to reduce supplemental benefits for non-bargaining participants as well as to allow the transfer of a portion of non-qualified pension obligations into the qualified plans.

Projected Benefit Payments

NSP-Minnesota's projected benefit payments:

(Millions of Dollars)	Projected Pension Benefit Payments	Gross Projected Postretirement Health Care Benefit Payments [(a)]
2023	$ 84	$ 6
2024	64	5
2025	64	5
2026	61	5
2027	59	4
2028-2032	279	17

(a) Amount is reported net of expected Medicare Part D subsidies, which are immaterial.

Defined Contribution Plans

Xcel Energy, which includes NSP-Minnesota, maintains 401(k) and other defined contribution plans that cover most employees. The expense to these plans for NSP-Minnesota was approximately $13 million in 2022 and $12 million in 2021 and 2020.

Multiemployer Plans

NSP-Minnesota contributes to several union multiemployer pension and other postretirement benefit plans, none of which are individually significant. These plans provide pension and postretirement health care benefits to certain union employees who may perform services for multiple employers and do not participate in the NSP-Minnesota sponsored pension and postretirement health care plans. Contributing to these types of plans creates risk that differs from providing benefits under NSP-Minnesota sponsored plans, in that if another participating employer ceases to contribute to a multiemployer plan, additional unfunded obligations may need to be funded over time by remaining participating employers.

10. Commitments and Contingencies

Legal

NSP-Minnesota is involved in various litigation matters in the ordinary course of business. The assessment of whether a loss is probable or is a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Management maintains accruals for losses probable of being incurred and subject to reasonable estimation.

Management is sometimes unable to estimate an amount or range of a reasonably possible loss in certain situations, including but not limited to when (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories.

In such cases, there is considerable uncertainty regarding the timing or ultimate resolution, including a possible eventual loss. For current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, would have a material effect on NSP-Minnesota's consolidated financial statements. Legal fees are generally expensed as incurred.

Rate Matters and Other

NSP-Minnesota is involved in various regulatory proceedings arising in the ordinary course of business. Until resolution, typically in the form of a rate order, uncertainties may exist regarding the ultimate rate treatment for certain activities and transactions. Amounts have been recognized for probable and reasonably estimable losses that may result. Unless otherwise disclosed, any reasonably possible range of loss in excess of any recognized amount is not expected to have a material effect on the consolidated financial statements.

Sherco — In 2018, NSP-Minnesota and Southern Minnesota Municipal Power Agency (Co-owner of Sherco Unit 3) reached a settlement with GE related to a 2011 incident, which damaged the turbine at Sherco Unit 3 and resulted in an extended outage for repair. NSP-Minnesota notified the MPUC of its proposal to refund settlement proceeds to customers through the fuel clause adjustment.

In March 2019, the MPUC approved NSP-Minnesota's settlement refund proposal. Additionally, the MPUC decided to withhold any decision as to NSP-Minnesota's prudence in connection with the incident at Sherco Unit 3 until after conclusion of an appeal pending between GE and NSP-Minnesota's insurers.

In February 2020, the Minnesota Court of Appeals affirmed the district court's judgment in favor of GE. In March 2020, NSP-Minnesota's insurers filed a petition seeking additional review by the Minnesota Supreme Court. In April 2020, the Minnesota Supreme Court denied the insurers' petition for further review, ending the litigation.

In January 2021, the Minnesota Office of the Attorney General and DOC recommended that NSP-Minnesota refund approximately $17 million of replacement power costs previously recovered through the fuel clause adjustment. NSP-Minnesota subsequently filed its response, asserting that it acted prudently in connection with the Sherco Unit 3 outage, the MPUC has previously disallowed $22 million of related costs and no additional refund or disallowance is appropriate.

A final decision by the MPUC is expected in mid-2024. A loss related to this matter is deemed remote.

MISO ROE Complaints — In November 2013 and February 2015, customer groups filed two ROE complaints against MISO TOs, which includes NSP-Minnesota and NSP-Wisconsin. The first complaint requested a reduction in base ROE transmission formula rates from 12.38% to 9.15% for the time period of Nov. 12, 2013 to Feb. 11, 2015, and removal of ROE adders (including those for RTO membership). The second complaint requested, for a subsequent time period, a base ROE reduction from 12.38% to 8.67%.

The FERC subsequently issued various related orders (including Opinion Nos. 569, 569A and 569B) related to ROE methodology/calculations and timing. NSP-Minnesota has processed refunds to customers for applicable complaint periods based on the ROE in the most recent applicable opinions.

The MISO TOs and various other parties have filed petitions for review of the FERC's most recent applicable opinions at the D.C. Circuit. In August 2022, the D.C. Circuit ruled that FERC had not adequately supported its conclusions, vacated FERC's related orders and remanded the issue back to FERC for further proceedings, which remain pending. Additional exposure, if any related to this matter is expected to be immaterial.

Environmental

New and changing federal and state environmental mandates can create financial liabilities for NSP-Minnesota, which are normally recovered through the regulated rate process.

Site Remediation

Various federal and state environmental laws impose liability where hazardous substances or other regulated materials have been or a portion of the cost to remediate sites where past activities of NSP-Minnesota's predecessors or other parties have caused environmental contamination.

Environmental contingencies could arise from various situations, including sites of former MGPs; and third-party sites, such as landfills, for which NSP-Minnesota is alleged to have sent wastes to that site.

Historical MGP, Landfill and Disposal Sites

NSP-Minnesota is investigating, remediating or performing post-closure actions at five MGP, landfill or other disposal sites across its service territories.

NSP-Minnesota has recognized its best estimate of costs/liabilities from final resolution of these issues, however, the outcome and timing are unknown. In addition, there may be insurance recovery and/or recovery from other potentially responsible parties, offsetting a portion of costs incurred.

Environmental Requirements — Water and Waste

Coal Ash Regulation — NSP-Minnesota's operations are subject to federal and state regulations that impose requirements for handling, storage, treatment and disposal of solid waste. Under the CCR Rule, utilities are required to complete groundwater sampling around their CCR landfills and surface impoundments. Currently, NSP-Minnesota has three regulated ash units in operation.

NSP-Minnesota is conducting groundwater sampling and monitoring and implementing assessment of corrective measures at certain CCR landfills and surface impoundments. No results above the groundwater protection standards in the rule were identified.

Federal Clean Water Act Section 316(b) — The Federal Clean Water Act requires the EPA to regulate cooling water intake structures to assure they reflect the best technology available for minimizing impingement and entrainment of aquatic species. NSP-Minnesota estimates capital expenditures of approximately $40 million may be required for NSP-Minnesota to comply with the requirements pending approval of mitigation plans from the Minnesota Pollution Control Agency. NSP-Minnesota anticipates these costs will be recoverable through regulatory mechanisms.

AROs — AROs have been recorded for NSP-Minnesota's assets. For nuclear assets, the ARO is associated with the decommissioning of NSP-Minnesota nuclear generating plants.

Aggregate fair value of NSP-Minnesota's legally restricted assets for funding future nuclear decommissioning was $2.9 billion and $3.3 billion at Dec. 31, 2022 and 2021, respectively.

NSP-Minnesota's AROs were as follows:

	2022				
(Millions of Dollars)	**Jan. 1, 2022**	**Amounts Incurred** (a)	**Accretion**	**Cash Flow Revisions** (b)	**Dec. 31, 2022**
Electric					
Nuclear	$ 2,056	$ —	$ 104	$ —	$ 2,160
Wind	384	25	15	(8)	416
Steam and other production	73	—	2	—	75
Distribution	16	—	—	—	16
Natural gas					
Transmission and distribution	55	—	2	2	59
Common					
Miscellaneous	1	—	—	—	1
Total liability	$ 2,585	$ 25	$ 123	$ (6)	$ 2,727

(a) Amounts incurred relate to the wind farms placed in service in 2022 (Dakota Range and Rock Aetna).

(b) In 2022, AROs were revised for changes in timing and estimates of cash flows. Changes in electric wind AROs were related to the repowering and extended retirement date of Nobles. Changes in gas transmission and distribution AROs were primarily related to changes in labor rates coupled with increased gas line mileage and number of services.

(Millions of Dollars)	Jan. 1, 2021	Amounts Incurred (a)	Accretion	Cash Flow Revisions (b)	Dec. 31, 2021
	2021				
Electric					
Nuclear	$ 1,957	$ —	$ 99	$ —	$ 2,056
Wind	270	101	13	—	384
Steam and other production	67	6	2	(2)	73
Distribution	16	—	—	—	16
Miscellaneous	—	—	—	—	—
Natural gas					
Transmission and distribution	39	—	2	14	55
Common					
Miscellaneous	1	—	—	—	1
Total liability	$ 2,350	$ 107	$ 116	$ 12	$ 2,585

(a) Amounts incurred relate to the wind farms placed in service in 2021 (Blazing Star 2, Mower and Freeborn) and removal of a utility scale battery asset.

(b) In 2021, AROs were revised for changes in timing and estimates of cash flows. Changes in gas transmission and distribution AROs were primarily related to changes in labor rates coupled with increased gas line mileage and number of services.

Indeterminate AROs — Outside of the recorded asbestos AROs, other plants or buildings may contain asbestos due to the age of many of NSP-Minnesota's facilities, but no confirmation or measurement of the cost of removal could be determined as of Dec. 31, 2022. Therefore, an ARO has not been recorded for these facilities.

Nuclear Related

Nuclear Insurance — NSP-Minnesota's public liability for claims from any nuclear incident is limited to $13.7 billion under the Price-Anderson amendment to the Atomic Energy Act. NSP-Minnesota has $450 million of coverage for its public liability exposure with a pool of insurance companies. The remaining $13.2 billion of exposure is funded by the Secondary Financial Protection Program available from assessments by the federal government.

NSP-Minnesota is subject to assessments of up to $138 million per reactor-incident for each of its three reactors, for public liability arising from a nuclear incident at any licensed nuclear facility in the United States. The maximum funding requirement is $20 million per reactor-incident during any one year. Maximum assessments are subject to inflation adjustments.

NSP-Minnesota purchases insurance for property damage and site decontamination cleanup costs from NEIL and EMANI. The coverage limits are $2.8 billion for each of NSP-Minnesota's two nuclear plant sites. NEIL also provides business interruption insurance coverage up to $350 million, including the cost of replacement power during prolonged accidental outages of nuclear generating units. Premiums are expensed over the policy term.

All companies insured with NEIL are subject to retroactive premium adjustments if losses exceed accumulated reserve funds. Capital has been accumulated in the reserve funds of NEIL and EMANI to the extent that NSP-Minnesota would have no exposure for retroactive premium assessments in case of a single incident under the business interruption and the property damage insurance coverage. NSP-Minnesota could be subject to annual maximum assessments of $12 million for business interruption insurance and $32 million for property damage insurance if losses exceed accumulated reserve funds.

Nuclear Fuel Disposal — NSP-Minnesota is responsible for temporarily storing spent nuclear fuel from its nuclear plants. The DOE is responsible for permanently storing spent fuel from U.S. nuclear plants, but no such facility is yet available.

NSP-Minnesota owns temporary on-site storage facilities for spent fuel at its Monticello and PI nuclear plants, which consist of storage pools and dry cask facilities. The Monticello dry-cask storage facility currently stores all 30 of the authorized canisters. The PI dry-cask storage facility currently stores 50 of the 64 authorized casks. Monticello's future spent fuel will continue to be placed in its spent fuel pool. The decommissioning plan addresses the disposition of spent fuel at the end of the licensed life. A CON for additional storage at the Monticello site has been filed with the MPUC, to support possible life extension to 2040. NSP-Minnesota expects a decision by year-end 2023.

Regulatory Plant Decommissioning Recovery — Decommissioning activities for NSP-Minnesota's nuclear facilities are planned to begin at the end of each unit's authorized retirement dates, which can be different than the currently approved NRC operating licenses. These decommissioning activities are planned to be completed at both facilities by 2101.

NSP-Minnesota's current operating licenses allow continued use of its Monticello nuclear plant until 2030 and its PI nuclear plant until 2033 for Unit 1 and 2034 for Unit 2. The MPUC reaffirmed a 60-year DECON scenario, where Monticello continues operations under a 10-year license extension (approved in April 2022). NRC approval of the extension is pending.

Future decommissioning costs of nuclear facilities are estimated through triennial periodic studies that assess the costs and timing of planned nuclear decommissioning activities for each unit. The 2020 nuclear decommissioning filing was approved by the MPUC and became effective in 2022.

Obligations for decommissioning are expected to be funded 100% by the external decommissioning trust fund. NSP-Minnesota had $2.9 billion and $3.3 billion of assets held in external decommissioning trusts at Dec. 31, 2022, and 2021, respectively.

See Note 10 to the consolidated financial statements for additional discussion.

Leases

NSP-Minnesota evaluates contracts that may contain leases, including PPAs and arrangements for the use of office space and other facilities, vehicles and equipment. A contract contains a lease if it conveys the exclusive right to control the use of a specific asset. A contract determined to contain a lease is evaluated further to determine if the arrangement is a finance lease.

ROU assets represent NSP-Minnesota's rights to use leased assets. The present value of future operating lease payments is recognized in current and noncurrent operating lease liabilities. These amounts, adjusted for any prepayments or incentives, are recognized as operating lease ROU assets.

Most of NSP-Minnesota's leases do not contain a readily determinable discount rate. Therefore, the present value of future lease payments is generally calculated using the estimated incremental borrowing rate (weighted average of 3.8%).

NSP-Minnesota has elected to utilize the practical expedient under which non-lease components, such as asset maintenance costs included in payments, are not deducted from minimum lease payments for the purposes of lease accounting and disclosure.

Leases with an initial term of 12 months or less are classified as short-term leases and are not recognized on the consolidated balance sheet.

Operating lease ROU assets:

(Millions of Dollars)	Dec. 31, 2022	Dec. 31, 2021
PPAs	$ 556	$ 556
Other	78	74
Gross operating lease ROU assets	634	630
Accumulated amortization	(310)	(222)
Net operating lease ROU assets	$ 324	$ 408

Components of lease expense:

(Millions of Dollars)	2022	2021	2020
Operating leases			
PPA capacity payments	$ 98	$ 96	$ 89
Other operating leases [(a)]	9	8	8
Total operating lease expense [(b)]	$ 107	$ 104	$ 97

(a) Includes short-term lease expense of $3 million, $2 million and $2 million for 2022, 2021 and 2020, respectively.
(b) PPA capacity payments are included in electric fuel and purchased power on the consolidated statements of income. Expense for other operating leases is included in O&M expense and electric fuel and purchased power.

Commitments under operating leases as of Dec. 31, 2022:

(Millions of Dollars)	PPA [(a)] [(b)] Operating Leases	Other Operating Leases	Total Operating Leases
2023	$ 98	$ 12	$ 110
2024	100	7	107
2025	79	8	87
2026	40	7	47
2027	—	7	7
Thereafter	—	24	24
Total minimum obligation	317	65	382
Interest component of obligation	(19)	(9)	(28)
Present value of minimum obligation	$ 298	$ 56	354
Less current portion			(98)
Noncurrent operating lease liabilities			$ 256
Weighted-average remaining lease term in years			7.6

(a) Amounts do not include PPAs accounted for as executory contracts and/or contingent payments, such as energy payments on renewable PPAs.
(b) PPA operating leases contractually expire at various dates through 2026.

PPAs and Fuel Contracts

Non-Lease PPAs — NSP-Minnesota has entered into PPAs with other utilities and energy suppliers for purchased power to meet system load and energy requirements, operating reserve obligations and as part of wholesale and commodity trading activities. In general, these agreements provide for energy payments, based on actual energy delivered and capacity payments. Certain PPAs, accounted for as executory contracts with various expiration dates through 2033, contain minimum energy purchase commitments. Total energy payments on those contracts were $182 million, $149 million and $112 million in 2022, 2021 and 2020, respectively.

Included in electric fuel and purchased power expenses for PPAs accounted for as executory contracts were payments for capacity of $60 million, $55 million and $52 million in 2022, 2021 and 2020, respectively.

Capacity and energy payments are contingent on the IPPs meeting contract obligations, including plant availability requirements. Certain contractual payments are adjusted based on market indices. The effects of price adjustments on financial results are mitigated through purchased energy cost recovery mechanisms.

At Dec. 31, 2022, the estimated future payments for capacity and energy that NSP-Minnesota is obligated to purchase pursuant to these executory contracts, subject to availability, were as follows:

(Millions of Dollars)	Capacity	Energy [(a)]
2023	$ 61	$ 50
2024	63	45
2025	26	51
2026	9	48
2027	7	55
Thereafter	3	28
Total [(b)]	$ 169	$ 277

(a) Excludes contingent energy payments for renewable energy PPAs.
(b) Includes amounts allocated to NSP-Wisconsin through intercompany charges.

Fuel Contracts — NSP-Minnesota has entered into various long-term commitments for the purchase and delivery of a significant portion of its coal, nuclear fuel and natural gas requirements. These contracts expire in various years between 2023 and 2037. NSP-Minnesota is required to pay additional amounts depending on actual quantities shipped under these agreements.

Estimated minimum purchases for these contracts as of Dec. 31, 2022:

(Millions of Dollars)	Coal	Nuclear fuel	Natural gas supply	Natural gas storage and transportation
2023	$ 227	$ 144	$ 130	$ 158
2024	110	112	1	148
2025	17	158	1	138
2026	1	37	—	143
2027	1	155	—	98
Thereafter	—	194	—	116
Total [(a)]	$ 356	$ 800	$ 132	$ 801

(a) Includes amounts allocated to NSP-Wisconsin through intercompany charges.

VIEs

Under certain PPAs, NSP-Minnesota purchases power from IPPs for which NSP-Minnesota is required to reimburse fuel costs, or to participate in tolling arrangements under which NSP-Minnesota procures the natural gas required to produce the energy that it purchases. NSP-Minnesota has determined that certain IPPs are VIEs. NSP-Minnesota is not subject to risk of loss from the operations of these entities, and no significant financial support is required other than contractual payments for energy and capacity. NSP-Minnesota evaluated each of these VIEs for possible consolidation, including review of qualitative factors such as the length and terms of the contract, control over O&M, control over dispatch of electricity, historical and estimated future fuel and electricity prices, and financing activities.

NSP-Minnesota concluded that these entities are not required to be consolidated in its consolidated financial statements because it does not have the power to direct the activities that most significantly impact the entities' economic performance. NSP-Minnesota had approximately 1,322 MW and 1,347 MW of capacity under long-term PPAs at Dec. 31, 2022 and 2021, respectively, with entities that have been determined to be VIEs. These agreements have expiration dates through 2039.

11. Other Comprehensive Income

Changes in accumulated other comprehensive loss, net of tax, for the years ended Dec. 31:

	2022		
(Millions of Dollars)	Gains and Losses on Interest Rate Cash Flow Hedges	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive loss at Jan. 1	$ (17)	$ (3)	$ (20)
Other comprehensive loss before reclassifications, net of taxes of $ —	$ —	$ 1	$ 1
Losses reclassified from net accumulated other comprehensive loss:			
Amortization of interest rate hedges	1 [a]	—	1
Net current period other comprehensive income	1	1	2
Accumulated other comprehensive loss at Dec. 31	$ (16)	$ (2)	$ (18)

	2021		
(Millions of Dollars)	Gains and Losses on Interest Rate Cash Flow Hedges	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive loss at Jan. 1	$ (19)	$ (3)	$ (22)
Losses reclassified from net accumulated other comprehensive loss:			
Amortization of interest rate hedges	2 [a]	—	2
Net current period other comprehensive income	2	—	2
Accumulated other comprehensive loss at Dec. 31	$ (17)	$ (3)	$ (20)

(a) Included in interest charges.

12. Segment Information

NSP-Minnesota evaluates performance based on profit or loss generated from the product or service provided. These segments are managed separately because the revenue streams are dependent upon regulated rate recovery, which is separately determined for each segment.

NSP-Minnesota has the following reportable segments:

- **Regulated Electric** — The regulated electric utility segment generates, transmits and distributes electricity in Minnesota, North Dakota and South Dakota. In addition, this segment includes sales for resale and provides wholesale transmission service to various entities in the United States. The regulated electric utility segment also includes wholesale commodity and trading operations.
- **Regulated Natural Gas** — The regulated natural gas utility segment transports, stores and distributes natural gas primarily in portions of Minnesota and North Dakota.

NSP-Minnesota also presents All Other, which includes operating segments with revenues below the necessary quantitative thresholds. Those operating segments primarily include steam revenue, appliance repair services, non-utility real estate activities and revenues associated with processing solid waste into refuse-derived fuel.

Asset and capital expenditure information is not provided for NSP-Minnesota's reportable segments. As an integrated electric and natural gas utility, NSP-Minnesota operates significant assets that are not dedicated to a specific business segment. Reporting assets and capital expenditures by business segment would require arbitrary and potentially misleading allocations, which may not necessarily reflect the assets that would be required for the operation of the business segments on a stand-alone basis.

Certain costs, such as common depreciation, common O&M expenses and interest expense are allocated based on cost causation allocators across each segment. In addition, a general allocator is used for certain general and administrative expenses, including office supplies, rent, property insurance and general advertising.

NSP-Minnesota's segment information:

(Millions of Dollars)	2022	2021	2020
Regulated Electric			
Operating revenues — external [a]	$ 5,617	$ 5,094	$ 4,571
Intersegment revenue	1	1	1
Total revenues	$ 5,618	$ 5,095	$ 4,572
Depreciation and amortization	953	869	773
Interest charges and financing costs	257	240	221
Income tax (benefit) expense	(127)	(53)	(14)
Net income	626	566	553
Regulated Natural Gas			
Operating revenues — external [b]	$ 1,022	$ 623	$ 493
Intersegment revenue	2	1	—
Total revenues	$ 1,024	$ 624	$ 493
Depreciation and amortization	60	56	51
Interest charges and financing costs	22	18	17
Income tax expense	14	6	7
Net income	45	29	30
All Other			
Total revenues	$ 45	$ 39	$ 37
Depreciation and amortization	1	1	1
Income tax (benefit) expense	1	(1)	1
Net income	4	11	8
Consolidated Total			
Total revenues [a][b]	$ 6,687	$ 5,758	$ 5,102
Reconciling eliminations	(3)	(2)	(1)
Total operating revenues	$ 6,684	$ 5,756	$ 5,101
Depreciation and amortization	1,014	926	825
Interest charges and financing costs	279	258	238
Income tax (benefit) expense	(112)	(48)	(6)
Net income	675	606	591

(a) Operating revenues include $514 million, $501 million and $440 million of affiliate electric revenue for the years ended Dec. 31, 2022, 2021 and 2020, respectively. See Note 13 for further information.

(b) Operating revenues include $0 million, $1 million and $1 million of affiliate gas revenue for the years ended Dec. 31, 2022, 2021 and 2020, respectively. See Note 13 for further information.

13. Related Party Transactions

Xcel Energy Services Inc. provides management, administrative and other services for the subsidiaries of Xcel Energy Inc., including NSP-Minnesota. The services are provided and billed to each subsidiary in accordance with service agreements executed by each subsidiary. NSP-Minnesota uses the services provided by Xcel Energy Services Inc. whenever possible. Costs are charged directly to the subsidiary and are allocated if they cannot be directly assigned.

Xcel Energy, Inc., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS have established a utility money pool arrangement.

See Note 5 for further information.

The electric production and transmission costs of the entire NSP System are shared by NSP-Minnesota and NSP-Wisconsin. The Interchange Agreement provides for the sharing of all costs of generation and transmission facilities of the system, including capital costs.

Significant affiliate transactions among the companies and related parties including billings under the Interchange Agreement for the years ended Dec. 31:

(Millions of Dollars)	2022	2021	2020
Operating revenues:			
Electric	$ 514	$ 501	$ 440
Gas	—	1	1
Operating expenses:			
Purchased power	70	67	59
Transmission expense	132	121	109
Other operating expenses — paid to Xcel Energy Services Inc.	673	615	584
Interest income	1	—	—
Interest expense	1	—	—

Accounts receivable and payable with affiliates at Dec. 31:

	2022		2021	
(Millions of Dollars)	Accounts Receivable	Accounts Payable	Accounts Receivable	Accounts Payable
NSP-Wisconsin	$ 4	$ —	$ 13	$ —
PSCo	—	2	16	—
SPS	—	3	—	2
Other subsidiaries of Xcel Energy Inc.	41	84	—	61
	$ 45	$ 89	$ 29	$ 63

ITEM 9 — CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A — CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

NSP-Minnesota maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms.

In addition, the disclosure controls and procedures ensure that information required to be disclosed is accumulated and communicated to management, including the CEO and CFO, allowing timely decisions regarding required disclosure. As of Dec. 31, 2022, based on an evaluation carried out under the supervision and with the participation of NSP-Minnesota's management, including the CEO and CFO, of the effectiveness of its disclosure controls and procedures, the CEO and CFO have concluded that NSP-Minnesota's disclosure controls and procedures were effective.

Internal Control Over Financial Reporting

No changes in NSP-Minnesota's internal control over financial reporting occurred during the most recent fiscal quarter ended Dec. 31, 2022 that materially affected, or are reasonably likely to materially affect, NSP-Minnesota's internal control over financial reporting. NSP-Minnesota maintains internal control over financial reporting to provide reasonable assurance regarding the reliability of the financial reporting. NSP-Minnesota has evaluated and documented its controls in process activities, general computer activities, and on an entity-wide level.

During the year and in preparation for issuing its report for the year ended Dec. 31, 2022 on internal controls under section 404 of the Sarbanes-Oxley Act of 2002, NSP-Minnesota conducted testing and monitoring of its internal control over financial reporting. Based on the control evaluation, testing and remediation performed, NSP-Minnesota did not identify any material control weaknesses, as defined under the standards and rules issued by the Public Company Accounting Oversight Board, as approved by the SEC and as indicated in NSP-Minnesota's Management Report on Internal Controls over Financial Reporting, which is contained in Item 8 herein.

This annual report does not include an attestation report of NSP-Minnesota's independent registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by NSP-Minnesota's independent registered public accounting firm pursuant to the rules of the SEC that permit NSP-Minnesota to provide only management's report in this annual report.

ITEM 9B — OTHER INFORMATION

None.

ITEM 9C — DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

PART III

Items 10, 11 and 12 of Part III of Form 10-K have been omitted from this report for NSP-Minnesota in accordance with conditions set forth in General Instructions I(1)(a) and (b) of Form 10-K for wholly-owned subsidiaries.

ITEM 10 — DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

ITEM 11 — EXECUTIVE COMPENSATION

ITEM 12 — SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

ITEM 13 — CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information required under this Item is contained in Xcel Energy Inc.'s definitive Proxy Statement for its 2023 Annual Meeting of Shareholders, which is incorporated by reference.

ITEM 14 — PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information required under this Item (aggregate fees billed to us by our principal accountant, Deloitte & Touche LLP (PCAOB ID No. 34)) is contained in Xcel Energy Inc.'s Proxy Statement for its 2023 Annual Meeting of Shareholders, which is incorporated by reference.

PART IV

ITEM 15 — EXHIBIT AND FINANCIAL STATEMENT SCHEDULES

1	Consolidated Financial Statements:
	Management Report on Internal Controls Over Financial Reporting — For the year ended Dec. 31, 2022.
	Report of Independent Registered Public Accounting Firm — Financial Statements
	Consolidated Statements of Income — For each of the three years ended Dec. 31, 2022, 2021 and 2020.
	Consolidated Statements of Comprehensive Income — For each of the three years ended Dec. 31, 2022, 2021 and 2020.
	Consolidated Statements of Cash Flows — For each of the three years ended Dec. 31, 2022, 2021 and 2020.
	Consolidated Balance Sheets — As of Dec. 31, 2022 and 2021.
	Consolidated Statements of Common Stockholder's Equity — For each of the three years ended Dec. 31, 2022, 2021 and 2020.
2	Schedule II — Valuation and Qualifying Accounts and Reserves for each of the years ended Dec. 31, 2022, 2021 and 2020.
3	Exhibits
*	Indicates incorporation by reference
+	Executive Compensation Arrangements and Benefit Plans Covering Executive Officers and Directors

Exhibit Number	Description	Report or Registration Statement	Exhibit Reference
3.01*	Articles of Incorporation and Amendments of Northern Power Corp. (renamed Northern States Power Co. (a Minnesota corporation) on Aug. 21, 2000)	NSP-Minnesota Form 10-12G dated Oct. 5, 2000	3.01
3.02*	By-Laws of NSP-Minnesota as Amended and Restated on Jan. 25, 2019	NSP-Minnesota Form 10-K for the year ended Dec. 31, 2018	3.02
4.01*	Supplemental and Restated Trust Indenture, dated May 1, 1988, from NSP-Minnesota to Harris Trust and Savings Bank, as Trustee, providing for the issuance of First Mortgage Bonds, Supplemental Indentures between NSP-Minnesota and said Trustee	Xcel Energy Inc. Form S-3 dated April 18, 2018	4(b)(3)
4.02*	Supplemental Trust Indenture, dated as of June 1, 1995, from NSP-Minnesota to Harris Trust and Savings Bank, as Trustee, creating $250 million aggregate principal amount of 7.125% First Mortgage Bonds, Series due July 1, 2025	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2017	4.11
4.03*	Supplemental Trust Indenture, dated as of March 1, 1998, from NSP-Minnesota to Harris Trust and Savings Bank, as Trustee, creating $150 million aggregate principal amount of 6.5% First Mortgage Bonds, Series due March 1, 2028	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2017	4.12
4.04*	Supplemental Trust Indenture, dated as of Aug. 1, 2000 (Assignment and Assumption of Trust Indenture)	NSP-Minnesota Form 10-12G dated Oct. 5, 2000	4.51
4.05*	Indenture, dated as of July 1, 1999, by and between NSP-Minnesota and The Bank of New York Mellon Trust Company, NA (as successor to Norwest Bank Minnesota, NA), as Trustee, providing for the issuance of Sr. Debt Securities	Xcel Energy Inc. Form S-3 dated April 18, 2018	4(b)(7)
4.06*	Supplemental Indenture No. 2, dated Aug. 18, 2000, supplemental to the Indenture, dated as of July 1, 1999, among Xcel Energy Inc., NSP-Minnesota and The Bank of New York Mellon Trust Company, NA (as successor to Wells Fargo Bank Minnesota, NA), as Trustee	NSP-Minnesota Form 10-12G dated Oct. 5, 2000	4.63
4.07*	Supplemental Trust Indenture, dated as of July 1, 2005, by and between NSP-Minnesota and The Bank of New York Mellon Trust Company, NA (as successor to BNY Midwest Trust Company), as Trustee, creating $250 million aggregate principal amount of 5.25% First Mortgage Bonds, Series due July 15, 2035	NSP-Minnesota Form 8-K dated July 14, 2005	4.01
4.08*	Supplemental Trust Indenture, dated as of May 1, 2006, by and between NSP-Minnesota and The Bank of New York Mellon Trust Company, NA (as successor to BNY Midwest Trust Company), as Trustee, creating $400 million aggregate principal amount of 6.25% First Mortgage Bonds, Series due June 1, 2036	NSP-Minnesota Form 8-K dated May 18, 2006	4.01
4.09*	Supplemental Trust Indenture, dated as of June 1, 2007, by and between NSP-Minnesota and The Bank of New York Mellon Trust Company, NA (as successor to BNY Midwest Trust Company), as Trustee, creating $350 million aggregate principal amount of 6.20% First Mortgage Bonds, Series due July 1, 2037	NSP-Minnesota Form 8-K dated June 19, 2007	4.01
4.10*	Supplemental Trust Indenture, dated as of Nov. 1, 2009, by and between NSP-Minnesota and The Bank of New York Mellon Trust Company., NA, as Trustee, creating $300 million aggregate principal amount of 5.35% First Mortgage Bonds, Series due Nov. 1, 2039	NSP-Minnesota Form 8-K dated Nov. 16, 2009	4.01
4.11*	Supplemental Trust Indenture, dated as of Aug. 1, 2010, by and between NSP-Minnesota and The Bank of New York Mellon Trust Company, NA, as Trustee, creating $250 million aggregate principal amount of 4.85% First Mortgage Bonds, Series due Aug. 15, 2040	NSP-Minnesota Form 8-K dated Aug. 4, 2010	4.01
4.12*	Supplemental Trust Indenture, dated as of Aug. 1, 2012, by and between NSP-Minnesota and The Bank of New York Mellon Trust Company, NA, as Trustee, creating $500 million aggregate principal amount of 3.40% First Mortgage Bonds, Series due Aug. 15, 2042	NSP-Minnesota Form 8-K dated Aug. 13, 2012	4.01
4.13*	Supplemental Trust Indenture, dated as of May 1, 2013, by and between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as Trustee, creating $400 million aggregate principal amount of 2.60% First Mortgage Bonds, Series due May 15, 2023	NSP-Minnesota Form 8-K dated May 20, 2013	4.01

4.14*	Supplemental Trust Indenture, dated as of May 1, 2014, by and between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as Trustee, creating $300 million aggregate principal amount of 4.125% First Mortgage Bonds, Series due May 15, 2044	NSP-Minnesota Form 8-K dated May 13, 2014	4.01
4.15*	Supplemental Trust Indenture, dated as of Aug. 1, 2015, by and between NSP-Minnesota and The Bank of New York Mellon Company, N.A., as Trustee, creating $300 million aggregate principal amount of 4.00% First Mortgage Bonds, Series due Aug. 15, 2045	NSP-Minnesota Form 8-K dated Aug. 11, 2015	4.01
4.16*	Supplemental Trust Indenture, dated as of May 1, 2016, by and between NSP-Minnesota and The Bank of NY Mellon Trust Company, N.A., as Trustee, creating $350 million aggregate principal amount of 3.60% First Mortgage Bonds, Series due May 15, 2046	NSP-Minnesota Form 8-K dated May 31, 2016	4.01
4.17*	Supplemental Trust Indenture, dated as of Sept. 1, 2017, by and between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as Trustee, creating $600 million aggregate principal amount of 3.60% First Mortgage Bonds, Series due Sept. 15, 2047	NSP-Minnesota Form 8-K dated Sept. 13, 2017	4.01
4.18*	Supplemental Trust Indenture, dated as of Sept. 1, 2019, by and between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as Trustee, creating $600 million aggregate principal amount of 2.90% First Mortgage Bonds, Series due March 1, 2050	NSP-Minnesota Form 8-K dated Sept. 10, 2019	4.01
4.19*	Supplemental Indenture, dated as of June 8, 2020, by and between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as Trustee, creating $700 million aggregate principal amount of 2.60% First Mortgage Bonds, Series due June 1, 2051	NSP-Minnesota 8-K dated June 15, 2020	4.01
4.20*	Supplemental Indenture, dated as of March 1, 2021, by and between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as Trustee, creating $425 million principal amount of 2.25% First Mortgage Bonds, Series due April 1, 2031 and $425 million principal amount of 3.20% First Mortgage Bonds, Series due April 1, 2052	NSP-Minnesota 8-K dated March 30, 2021	4.01
4.21*	Supplemental Indenture, dated as of May 1, 2022, by and between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as Trustee, creating $500 million aggregate principal amount of 4.50% First Mortgage Bonds, Series due June 1, 2052	NSP-Minnesota 8-K dated May 9, 2022	4.01
10.01*+	Xcel Energy Inc. Nonqualified Pension Plan (2009 Restatement)	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	10.02
10.02*+	Xcel Energy Senior Executive Severance and Change-in-Control Policy (2009 Amendment and Restatement)	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	10.05
10.03*+	Second Amendment to Exhibit 10.02 dated Oct. 26, 2011	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2011	10.18
10.04*+	Fifth Amendment to Exhibit 10.02 dated May 3, 2016	Xcel Energy Inc. Form 10-Q for the quarter ended June 30, 2016	10.01
10.05*+	Seventh Amendment to Exhibit 10.02 dated May 7, 2018	Xcel Energy Inc. Form 10-Q for the quarter ended June 30, 2018	10.01
10.06*+	Eighth Amendment to Exhibit 10.02 dated March 31, 2020	Xcel Energy Inc. Form 10-Q for the quarter ended March 31, 2020	10.02
10.07*+	Ninth Amendment to Exhibit 10.02 dated May 22, 2020	Xcel Energy Inc. Form 10-Q for the quarter ended June 30, 2020	10.01
10.08*+	Xcel Energy Inc. Supplemental Executive Retirement Plan as amended and restated Jan. 1, 2009	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	10.17
10.09*+	Xcel Energy Inc. Executive Annual Incentive Plan (as amended and restated effective Feb. 17, 2010)	Xcel Energy Inc. Definitive Proxy Statement dated April 6, 2010	Appendix A
10.10*+	First Amendment to Exhibit 10.09 dated Feb. 20, 2013	Xcel Energy Inc. Form 10-Q for the quarter ended March 31, 2013	10.01
10.11*+	Xcel Energy Inc. Executive Annual Incentive Award Plan Form of Restricted Stock Agreement	Xcel Energy Inc. Form 10-Q for the quarter ended Sept. 30, 2009	10.08
10.12*+	Xcel Energy Inc. Nonqualified Deferred Compensation Plan (2009 Restatement)	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	10.07
10.13*+	First Amendment to Exhibit 10.12 effective Nov. 29, 2011	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2011	10.17
10.14*+	Second Amendment to Exhibit 10.12 dated May 21, 2013	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2013	10.22
10.15*+	Third Amendment to Exhibit 10.12 dated Sept. 30, 2016	Xcel Energy Inc. Form 10-Q for the quarter ended Sept. 30, 2016	10.01
10.16*+	Fourth Amendment to Exhibit 10.12 dated Oct. 23, 2017	Xcel Energy Inc. Form 10-Q for the quarter ended Sept. 30, 2017	10.1
10.17*+	Xcel Energy Inc. Amended and Restated 2015 Omnibus Incentive Plan	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2018	10.34
10.18*+	Form of Terms and Conditions under the Xcel Energy Inc. Amended and Restated 2015 Omnibus Incentive Plan for Awards of Restricted Stock Units and/or Performance Share Units	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2018	10.35
10.19*+	Form of Award Agreement for Restricted Stock Units and/or Performance Share Units under the Xcel Energy Inc. Amended and Restated 2015 Omnibus Incentive Plan for awards since 2020	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2019	10.33
10.20*+	Stock Equivalent Plan for Non-Employee Directors of Xcel Energy Inc. as amended and restated effective Feb. 23, 2011	Xcel Energy Inc. Definitive Proxy Statement dated April 5, 2011	Schedule 14A
10.21*+	Stock Equivalent Program for Non-Employee Directors of Xcel Energy Inc. under the Xcel Energy Inc. 2015 Omnibus Incentive Plan	Xcel Energy Inc. Form 8-K dated May 26, 2015	10.02
10.22*+	Summary of Non-Employee Director Compensation, effective as of Oct. 1, 2021	Xcel Energy Inc. Form 10-Q for the quarter ended September 30, 2021	10.01
10.23*+	Stock Program for Non-Employee Directors of Xcel Energy Inc. as Amended and Restated on Dec. 12, 2017 under the 2015 Omnibus Incentive Plan	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2018	10.36
10.24*+	Form of Services Agreement between Xcel Energy Services Inc. and utility companies	Xcel Energy Inc. Form U5B dated Nov. 16, 2000	H-1
10.25*	Restated Interchange Agreement dated Jan. 16, 2001 between NSP-Wisconsin and NSP-Minnesota	NSP-Wisconsin Form S-4 dated Jan. 21, 2004	10.01

10.26*	Fourth Amended and Restated Credit Agreement, dated as of September 19, 2022, among NSP-Minnesota, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A. and Barclays Bank PLC, as Syndication Agents, and Citibank, N.A., MUFG Bank, Ltd., and Wells Fargo Bank, National Association, as Documentation Agents	Xcel Energy Inc. Form 8-K dated Sept. 19, 2022	99.02
23.01	Consent of Independent Registered Public Accounting Firm.		
31.01	Principal Executive Officer's certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.		
31.02	Principal Financial Officer's certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.		
32.01	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.		
101.INS	Inline XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document		
101.SCH	Inline XBRL Schema		
101.CAL	Inline XBRL Calculation		
101.DEF	Inline XBRL Definition		
101.LAB	Inline XBRL Label		
101.PRE	Inline XBRL Presentation		
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)		

SCHEDULE II

NSP-Minnesota and Subsidiaries Valuation and Qualifying Accounts Years Ended Dec. 31

	Allowance for bad debts		
(Millions of Dollars)	2022	2021	2020
Balance at Jan. 1	$ 45	$ 33	$ 23
Additions charged to costs and expenses	21	24	24
Additions charged to other accounts [(a)]	6	5	5
Deductions from reserves [(b)]	(26)	(17)	(19)
Balance at Dec. 31	$ 46	$ 45	$ 33

(a) Recovery of amounts previously written-off.
(b) Deductions related primarily to bad debt write-offs.

ITEM 16 — FORM 10-K SUMMARY

None.

Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this annual report to be signed on its behalf by the undersigned thereunto duly authorized.

NORTHERN STATES POWER COMPANY
(A MINNESOTA CORPORATION)

Feb. 23, 2023

/s/ BRIAN J. VAN ABEL
Brian J. Van Abel
Executive Vice President, Chief Financial Officer and Director

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities on the date indicated above.

/s/ ROBERT C. FRENZEL
Robert C. Frenzel
Chairman, Chief Executive Officer and Director
(Principal Executive Officer)

/s/ CHRISTOPHER B. CLARK
Christopher B. Clark
President and Director

/s/ BRIAN J. VAN ABEL
Brian J. Van Abel
Executive Vice President, Chief Financial Officer and Director
(Principal Accounting Officer and Principal Financial Officer)

SUPPLEMENTAL INFORMATION TO BE FURNISHED WITH REPORTS FILED PURSUANT TO SECTION 15(D) OF THE ACT BY REGISTRANTS WHICH HAVE NOT REGISTERED SECURITIES PURSUANT TO SECTION 12 OF THE ACT

NSP-Minnesota has not sent, and does not expect to send, an annual report or proxy statement to its security holder.

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING

We consent to the incorporation by reference in Registration Statement No. 333-255446-04 on Form S-3 of our report dated February 23, 2023, relating to the financial statements and financial statement schedule of Northern States Power Company, a Minnesota corporation, and subsidiaries appearing in this Annual Report on Form 10-K of Northern States Power Company, a Minnesota corporation, for the year ended December 31, 2022.

/s/ DELOITTE & TOUCHE LLP
Minneapolis, Minnesota
February 23, 2023

I, Robert C. Frenzel, certify that:

1. I have reviewed this report on Form 10-K of Northern States Power Company (a Minnesota corporation);
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: Feb. 23, 2023

/s/ ROBERT C. FRENZEL
Robert C. Frenzel
Chairman, Chief Executive Officer and Director

I, Brian J. Van Abel, certify that:

1. I have reviewed this report on Form 10-K of Northern States Power Company (a Minnesota corporation);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: Feb. 23, 2023

/s/ BRIAN J. VAN ABEL
Brian J. Van Abel
Executive Vice President, Chief Financial Officer and Director

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Northern States Power Company, a Minnesota corporation (NSP-Minnesota), on Form 10-K for the year ended Dec. 31, 2022, as filed with the SEC on the date hereof (Form 10-K), each of the undersigned officers of NSP-Minnesota certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to such officer's knowledge:

(1) The Form 10-K fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of NSP-Minnesota as of the dates and for the periods expressed in the Form 10-K.

Date: Feb. 23, 2023

/s/ ROBERT C. FRENZEL
Robert C. Frenzel
Chairman, Chief Executive Officer and Director

/s/ BRIAN J. VAN ABEL
Brian J. Van Abel
Executive Vice President, Chief Financial Officer and Director

The foregoing certification is being furnished solely pursuant to 18 U.S.C. Section 1350 and is not being filed as part of the Report or as a separate disclosure document.

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to NSP-Minnesota and will be retained by NSP-Minnesota and furnished to the SEC or its staff upon request.

Northern States Power Company Minnesota
Prepaid Pension Asset

Line No		2017	2018	2019	2020	2021	2022	2023	2024
2	**Beginning Asset (Liability) Balance**	129,569,692	154,828,347	183,510,347	195,621,202	208,196,202	210,125,202	187,653,202	180,555,202
3	Recognized Expense	(34,862,000)	(34,465,000)	(34,707,000)	(31,384,000)	(31,811,000)	(27,379,000)	(30,377,000)	(28,798,000)
4	Cash Contributions	60,740,655	63,147,000	46,817,855	43,959,000	34,109,000	4,907,000	23,279,000	20,623,000
5	Other	(620,000)				(369,000)			
6	**Ending Asset (Liability) Balance**	154,828,347	183,510,347	195,621,202	208,196,202	210,125,202	187,653,202	180,555,202	172,380,202
7									
8									

Line No		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
9		**2024 Test Year**												
11	**Beginning Asset (Liability) Balance**	180,555,202	198,778,369	196,378,535	193,978,702	191,578,869	189,179,035	186,779,202	184,379,369	181,979,535	179,579,702	177,179,869	174,780,035	180,555,202
12	Recognized Expense	(2,399,833)	(2,399,833)	(2,399,833)	(2,399,833)	(2,399,833)	(2,399,833)	(2,399,833)	(2,399,833)	(2,399,833)	(2,399,833)	(2,399,833)	(2,399,833)	(28,798,000)
13	Cash Contributions	20,623,000												20,623,000
14	**Ending Asset (Liability) Balance**	198,778,369	196,378,535	193,978,702	191,578,869	189,179,035	186,779,202	184,379,369	181,979,535	179,579,702	177,179,869	174,780,035	172,380,202	172,380,202
15														
16	**Beginning Asset (Liability) Balance**	180,555,202												172,380,202
17	ADIT Percent	-27.97%												-27.97%
18	ADIT Amount	(50,504,540)												(48,217,845)
19	Net Prepaid Pension Asset	130,050,662												124,162,357
20	% to MN Gas	7.73%												7.73%
21	**Actual Total**	10,056,167												9,600,854
22													**2024 Forecast BOY & EOY Average**	**9,828,511**

Northern Sates Power Company Minnesota
Prepaid Pension Asset

Line No		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
2	**Beginning Asset (Liability) Balance**	(20,181,500)	(20,181,500)	(6,480,500)	22,166,500	71,689,833	102,395,562	115,599,406	114,121,017	129,569,692	154,828,347	183,510,347	195,621,202	208,196,202	210,125,202	187,653,202
3	Recognized Expense		(6,481,000)	(12,728,000)	(28,981,000)	(41,706,000)	(38,911,000)	(34,213,000)	(33,981,000)	(34,862,000)	(34,465,000)	(34,707,000)	(31,384,000)	(31,811,000)	(27,379,000)	(30,377,000)
4	Cash Contributions		20,182,000	41,375,000	79,584,333	72,411,729	52,114,844	32,734,611	49,429,675	60,740,655	63,147,000	46,817,855	43,959,000	34,109,000	4,907,000	23,279,000
5	Other				(1,080,000)					(620,000)				(369,000)		
6	**Ending Asset (Liability) Balance**	(20,181,500)	(6,480,500)	22,166,500	71,689,833	102,395,562	115,599,406	114,121,017	129,569,692	154,828,347	183,510,347	195,621,202	208,196,202	210,125,202	187,653,202	180,555,202
	Expense and Contribution Support Reference*		A1	A2	A3	A4	A5	A6	A7	A8	A9	A10	A11	A12	A13	A14

*NSPM amounts indicated by red boxes on reference documents

WELLS FARGO

T OF
ND OTHER RECEIPTS

XCEL ENERGY PENSION PLAN

DECEMBER 31,2009
THROUGH DECEMBER 31,2010

DATE	DESCRIPTION	
CONTRIBUTIONS		
EMPLOYER CONTRIBUTION		
12/01/10	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION DIS OPS	1,466,000.00
2/01/10	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPM	20,182,000.00
12/01/10	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPW	3,086,000.00
12/01/10	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION XEPC	8,000.00
12/01/10	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION XS	9,390,000.00
	TOTAL EMPLOYER CONTRIBUTION	34,132,000.00
	TOTAL CONTRIBUTIONS	34,132,000.00

XCEL ENERGY INC. - Qualified Pension Plans
FAS 87 Budget Estimates by Legal Entity
($ in Thousands)

EXHIBIT I
Page 1 of 6

2010	Service Cost	Interest Cost	Expected Return on Assets	Amortizations: Prior Service Cost	Amortizations: Net (Gain)/Loss	Net Cost	Aggregate Normal Cost	Recognized Expense	January 1 Prepaid (Accrued)	Contribution
Xcel Energy Pension Plan (XEPP)										
Discontinued Operations[1]	-	3,974	(5,640)	1,055	1,056	445	N/A	445	26,629	1,466
Xcel Energy Nuclear	5,570	3,725	(5,293)	234	58	4,294	449	449	5,819	1,397
NSP - MN	21,166	50,204	(71,318)	11,492	17,670	29,214	6,032	6,032	401,187	18,785
NSP - WI	4,260	8,311	(11,800)	1,629	2,463	4,863	N/A	4,863	57,487	3,086
Xcel Services[2]	19,001	25,270	(35,882)	4,391	1,880	14,660	N/A	14,660	76,739	9,390
XEPC (former EMI)	-	21	(30)	20	(28)	(17	N/A	(17)	(426)	8
Total XEPP	49,997	91,505	(129,963)	18,821	23,099	53,459	6,481	26,432	567,435	34,132
NCE Non-Bargaining Pension Plan										
Discontinued Operations - Cheyenne	-	190	(217)	121	69	163	N/A	163	1,435	-
PSCo	4,581	8,960	(10,236)	3,432	(98)	6,639	N/A	6,639	8,116	-
SPS	2,294	4,104	(4,690)	1,504	3,329	6,541	N/A	6,541	55,139	-
Total NCE	6,875	13,254	(15,143)	5,057	3,300	13,343	N/A	13,343	64,690	-
SPS Bargaining Plan										
SPS	4,714	15,893	(22,852)	-	1,497	(748)	N/A	(748)	129,375	-
Total SPS	4,714	15,893	(22,852)	-	1,497	(748)	N/A	(748)	129,375	-
PSCo Bargaining Plan										
Discontinued Operations - Cheyenne	-	679	(987)	7	394	93	N/A	93	6,868	-
PSCo	11,561	43,679	(63,373)	(3,228)	20,025	8,664	N/A	8,664	326,580	-
Total PSCo	11,561	44,358	(64,360)	(3,221)	20,419	8,757	N/A	8,757	333,448	-
Total Xcel Energy	73,147	165,010	(232,318)	20,657	48,315	74,811	6,481	47,784	1,094,948	34,132

[1] Includes NRG, BMG, Viking, Natro Gas, Utility Engineering, Seren, Quixx, Crockett and QPS
[2] Includes Eloigne

NSPM
Aggregate Cost
6,481,000

Assumptions	
Discount Rate - FAS 87	6.00%
Discount Rate - Aggregate Normal Cost	8.00%
Salary Scale	4.00%
Expected Return on Assets	
XEPP	8.00%
NCE	7.00%
SPS	6.75%
PSCo	8.00%

Recognized Expense: Total FAS 87 expense, excluding Minnesota and Xcel Energy Nuclear, plus aggregate normal cost allocated to Minnesota and Xcel Energy Nuclear.

Assumed mortality table is RP-2000.
Contributions are allocated based on PBO for each legal entity.
See October 1, 2010 letter for additional information on data, assumptions, methods and plan provisions.

WELLS FARGO

FD411
DETAIL STATEMENT OF
CONTRIBUTIONS AND OTHER RECEIPTS

XCEL - TOTAL PENSION PLAN COMPOSITE
BASE CURRENCY: USD

PAGE 103
DECEMBER 31,2010
THROUGH DECEMBER 31,2011

DATE	DESCRIPTION	
CONTRIBUTIONS		
EMPLOYER CONTRIBUTION		
01/03/11	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION DIS OPS	2,992,000.00
01/03/11	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPM	41,375,000.00
01/03/11	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPW	6,446,000.00
01/03/11	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION XEPC	15,000.00
01/03/11	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION XS	19,807,000.00
	TOTAL EMPLOYER CONTRIBUTION	70,635,000.00
	TOTAL CONTRIBUTIONS	70,635,000.00

XCEL ENERGY INC. - Qualified Pension Plans
U.S. GAAP Cost Estimates by Legal Entity
($ in Thousands)

EXHIBIT I
Page 1 of 6

				Amortizations						
2011	Service Cost	Interest Cost	Expected Return on Assets	Prior Service Cost	Net (Gain)/Loss	Net Cost	Aggregate Normal Cost	Recognized Cost	January 1 Prepaid (Accrued)	Contribution
Xcel Energy Pension Plan (XEPP)										
Discontinued Operations[1]	-	3,819	(5,461)	1,055	2,025	1,438	N/A	1,438	27,650	2,992
Xcel Energy Nuclear	6,042	3,589	(5,144)	264	424	5,175	878	878	2,922	3,023
NSP - MN	21,974	48,357	(69,097)	12,905	28,312	42,451	11,850	11,850	390,758	38,352
NSP - WI	4,271	8,031	(11,484)	1,895	4,070	6,783	N/A	6,783	55,710	6,446
Xcel Services[2]	19,616	24,510	(35,068)	4,548	5,909	19,515	N/A	19,515	71,469	19,807
XEPC (former EMI)	-	21	(29)	18	(28)	(18)	N/A	(18)	(401)	15
Total XEPP	51,903	88,327	(126,283)	20,685	40,712	75,344	12,728	40,446	548,108	70,635
NCE Non-Bargaining Pension Plan										
Discontinued Operations - Cheyenne	-	181	(212)	121	108	198	N/A	198	1,272	219
PSCo	5,215	9,363	(10,941)	3,450	1,166	8,253	N/A	8,253	1,477	11,310
SPS	2,507	4,086	(4,793)	1,505	4,217	7,522	N/A	7,522	48,598	5,176
Total NCE	7,722	13,630	(15,946)	5,076	5,491	15,973	N/A	15,973	51,347	16,705
SPS Bargaining Plan										
SPS	5,183	15,950	(21,523)	-	4,829	4,439	N/A	4,439	130,123	-
Total SPS	5,183	15,950	(21,523)	-	4,829	4,439	N/A	4,439	130,123	-
PSCo Bargaining Plan										
Discontinued Operations - Cheyenne	-	634	(843)	-	518	309	N/A	309	6,775	741
PSCo	12,511	42,871	(57,005)	(3,228)	26,960	22,109	N/A	22,109	317,916	49,259
Total PSCo	12,511	43,505	(57,848)	(3,228)	27,478	22,418	N/A	22,418	324,691	50,000
Total Xcel Energy	77,319	161,412	(221,600)	22,533	78,510	118,174	12,728	83,276	1,054,269	137,340

[1] Includes NRG, BMG, Viking, Natro Gas, Utility Engineering, Seren, Quixx, Crockett and QPS
[2] Includes Eloigne

Assumptions	
Discount Rate - U.S. GAAP	5.50%
Discount Rate - Aggregate Cost	8.00%
Salary Scale	4.00%
Expected Return on Assets	
XEPP	8.00%
NCE	7.00%
SPS	6.75%
PSCo	7.00%
Assumed Asset Return	0.00% in 2011 and equal to expected return thereafter

Recognized Cost: Total U.S. GAAP cost, excluding Minnesota and Xcel Energy Nuclear, plus aggregate normal cost allocated to Minnesota and Xcel Energy Nuclear.

Assumed mortality table is RP-2000.
Contributions already made are allocated in accordance with the January 31, 2011 trust statements. Expected contributions are allocated based on PBO for each legal entity.
See August 19, 2011 letter for additional information on data, assumptions, methods and plan provisions.

NSPM Aggregate Cost
12,728,000

FD411
DETAIL STATEMENT OF
CONTRIBUTIONS AND OTHER RECEIPTS

XCEL - TOTAL PENSION PLAN COMPOSITE
BASE CURRENCY: USD

PAGE 113
DECEMBER 31,2011
THROUGH DECEMBER 31,2012

DATE	DESCRIPTION	
CONTRIBUTIONS		
EMPLOYER CONTRIBUTION		
01/13/12	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION DIS OPS	6,003,000.00
01/13/12	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPM	79,306,000.00
01/13/12	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPW	12,261,000.00
01/13/12	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION XEPC	32,000.00
01/13/12	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION XS	38,309,000.00
12/20/12	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPM	278,333.00
12/20/12	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPW	260,804.00
12/20/12	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION XS	6,130,737.00
12/26/12	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION DISC OPS	19,010.00
12/26/12	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPM	232,772.00

Total NSPM Conribution	
$	79,306,000
$	278,333
$	79,584,333

XCEL ENERGY INC. - Qualified Pension Plans
U.S. GAAP Cost Estimates by Legal Entity
($ in Thousands)

EXHIBIT I
Page 1 of 2

2012	Service Cost	Interest Cost	Expected Return on Assets	Amortizations: Prior Service Cost	Amortizations: Net (Gain)/Loss	Net Cost	Aggregate Normal Cost	Recognized Cost	January 1 Prepaid (Accrued)	Contribution
Xcel Energy Pension Plan (XEPP)										
Discontinued Operations[1]	-	3,671	(5,048)	956	3,014	2,593	N/A	2,593	29,204	6,003
Xcel Energy Nuclear	6,356	3,543	(4,854)	242	913	6,200	2,082	2,082	770	5,802
NSP - MN	23,055	45,676	(62,461)	11,577	39,216	57,063	26,899	26,899	386,659	73,504
NSP - WI	4,568	7,670	(10,489)	1,771	5,843	9,363	N/A	9,363	55,373	12,261
Xcel Services[2]	21,146	24,135	(33,017)	4,725	10,855	27,844	N/A	27,844	71,761	38,309
XEPC (former EMI)	-	21	(29)	14	(24)	(18)	N/A	(18)	(368)	32
Total XEPP	55,125	84,716	(115,898)	19,285	59,817	103,045	28,981	68,763	543,399	135,911
NCE Non-Bargaining Pension Plan										
Discontinued Operations - Cheyenne	-	178	(237)	114	156	211	N/A	211	1,293	314
PSCo	5,978	9,402	(12,483)	3,456	3,129	9,482	N/A	9,482	4,537	16,381
SPS	2,780	3,923	(5,232)	1,438	5,150	8,059	N/A	8,059	46,253	7,149
Total NCE	8,758	13,503	(17,952)	5,008	8,435	17,752	N/A	17,752	52,083	23,844
SPS Bargaining Plan										
SPS	5,740	15,677	(19,696)	-	7,663	9,384	N/A	9,384	125,684	5,792
Total SPS	5,740	15,677	(19,696)	-	7,663	9,384	N/A	9,384	125,684	5,792
PSCo Bargaining Plan										
Discontinued Operations - Cheyenne	-	576	(730)	-	582	428	N/A	428	7,207	352
PSCo	16,741	41,703	(52,819)	(3,228)	31,073	33,470	N/A	33,470	345,066	24,648
Total PSCo	16,741	42,279	(53,549)	(3,228)	31,655	33,898	N/A	33,898	352,273	25,000
Total Xcel Energy	86,364	156,175	(207,095)	21,065	107,570	164,079	28,981	129,797	1,073,439	190,547

[1] Includes NRG, BMG, Viking, Natro Gas, Utility Engineering, Seren, Quixx, Crockett and QPS
[2] Includes Eloigne

Assumptions

Discount Rate - U.S. GAAP	5.00%
Discount Rate - Aggregate Cost	7.50%
Salary Scale	4.00%
Expected Return on Assets	
XEPP	7.50%
NCE	7.50%
SPS	6.50%
PSCo	6.50%

Recognized Cost: Total U.S. GAAP cost, excluding Minnesota and Xcel Energy Nuclear, plus aggregate normal cost allocated to Minnesota and Xcel Energy Nuclear.

See June 22, 2012 letter for additional information on data, assumptions, methods and plan provisions.
Contributions already made are allocated in accordance with the January 31, 2012 trust statements.

NSPM Aggregate Cost
28,981,000

WELLS FARGO

FD411
DETAIL STATEMENT OF
CONTRIBUTIONS AND OTHER RECEIPTS

XCEL - TOTAL PENSION PLAN COMPOSITE
BASE CURRENCY: USD

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DECEMBER 31,2012
THROUGH DECEMBER 31,2013

DATE	DESCRIPTION	
CONTRIBUTIONS		
EMPLOYER CONTRIBUTION		
01/11/13	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION DISC OPS	5,364,000.00
01/11/13	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPM - $66,627,000 AND XCEL NUCLEAR - $5,482,000	5,482,000.00
01/11/13	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPM - $66,627,000 AND XCEL NUCLEAR - $5,482,000	66,627,000.00
01/11/13	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPW	11,281,000.00
01/11/13	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION XCEL SERVICES	35,865,000.00
01/11/13	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION XEPC	31,000.00
09/03/13	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION	88,483.00
09/03/13	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION	47,875.00
09/03/13	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION	6,953.00
09/03/13	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION	12,851.00
09/03/13	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION	76.00
09/03/13	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION	41.00

Total NSPM Conribution
$ 66,627,000
$ 5,482,000
$ 271,933
$ 30,796
$ 72,411,729

WELLS FARGO

FD411
DETAIL STATEMENT OF
CONTRIBUTIONS AND OTHER RECEIPTS

XCEL - TOTAL PENSION PLAN COMPOSITE
BASE CURRENCY: USD

PAG[illegible]
DECEMBER 31,2012
THROUGH DECEMBER 31,2013

DATE	DESCRIPTION	
09/03/13	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION	15,083.00
09/03/13	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION	27,877.00
09/03/13	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION	88,139.00
09/03/13	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION	7,336.00
09/03/13	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION	162,900.00
09/03/13	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION	13,558.00
12/31/13	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION DISC OPS	2,243.00
12/31/13	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPM - $28,430 - XCEL NUCLEAR $2,366	28,430.00
12/31/13	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPM - $28,430 - XCEL NUCLEAR $2,366	2,366.00
12/31/13	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPW	4,865.00
12/31/13	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION XCEL SERVICES	15,442.00
12/31/13	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION XEPC	13.00
	TOTAL EMPLOYER CONTRIBUTION	125,174,531.00
	TOTAL CONTRIBUTIONS	125,174,531.00

$ 88,139	
$ 7,336	
$ 162,900	
$ 13,558	
$ 271,933	See below for support that total was NSPM plan contribution
$ 28,430	
$ 2,366	
$ 30,796	

WELLS FARGO

Custom
09/03/2013 04:45 PM ET
CUSTOMER ID: XCELE402
OPERATOR ID: LARSM402
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XCEL ENERGY INC.
Intraday Composite Report
As of 09/03/2013
Treasury Information Reporting

WELLS FARGO BANK, N.A.
NORTHERN STATES POWER COMPANY

Debit Transactions

9/3/2013 506 / BOOK TRANSFER DEBIT **Debit Amount:** 271,933.00
Cust Ref: COMPLETE **Bank Ref:**
Wells Ref: 130903108514
000000000840245 WELLS FARGO BANK NA TRUST CLEARING ACCOUNT MAC N9306-04B EC13090351901393 ORG=
Xcel Energy 414 Nicollet Mall Minneapolis MN 55 401 USA RFB=00845310 OBI=XEPP Plan Contributio
n NSPMN Attn: Brandon Krause /FTR/ BNF=D 000000000840245 Trust Wire Clearing
Completed Timestamp 130903115445 (Time Released)

Account Net Amount **-271,933.00**

XCEL ENERGY INC. - Qualified Pension Plans
U.S. GAAP Cost Estimates by Legal Entity
($ in Thousands)

EXHIBIT I
Page 1 of 6

2013	Service Cost	Interest Cost	Expected Return on Assets	Amortizations: Prior Service Cost	Amortizations: Net (Gain)/Loss	Net Cost	Aggregate Normal Cost	Recognized Cost	January 1 Prepaid (Accrued)	Contribution
Xcel Energy Pension Plan (XEPP)										
Discontinued Operations[1]	-	3,263	(4,747)	596	4,135	3,247	N/A	3,247	32,505	5,364
Xcel Energy Nuclear	7,161	3,352	(4,833)	65	1,723	7,468	3,205	3,205	331	5,482
NSP - MN	26,006	40,382	(58,319)	1,992	51,265	61,326	38,501	38,501	401,704	66,627
NSP - WI	5,682	6,924	(9,995)	417	7,924	10,952	N/A	10,952	58,179	11,281
Xcel Services[2]	22,612	22,040	(31,844)	2,913	17,673	33,394	N/A	33,394	86,199	35,865
XEPC (former EMI)	-	19	(28)	-	(15)	(24)	N/A	(24)	(318)	31
Total XEPP	61,461	75,980	(109,766)	5,983	82,705	116,363	41,706	89,275	578,600	124,650
NCE Non-Bargaining Pension Plan										
Discontinued Operations - Cheyenne	-	139	(220)	82	219	220	N/A	220	1,396	271
PSCo	6,171	7,505	(11,844)	2,164	6,221	10,217	N/A	10,217	12,031	14,681
SPS	2,975	3,139	(4,980)	870	6,343	8,347	N/A	8,347	45,533	6,169
Total NCE	9,146	10,783	(17,044)	3,116	12,783	18,784	N/A	18,784	58,960	21,121
SPS Bargaining Plan										
SPS	6,640	14,769	(18,990)	-	10,805	13,224	N/A	13,224	121,796	15,682
Total SPS	6,640	14,769	(18,990)	-	10,805	13,224	N/A	13,224	121,796	15,682
PSCo Bargaining Plan										
Discontinued Operations - Cheyenne	-	503	(675)	-	661	489	N/A	489	7,125	391
PSCo	19,035	38,655	(51,977)	(3,228)	37,197	39,682	N/A	39,682	335,909	29,609
Total PSCo	19,035	39,158	(52,652)	(3,228)	37,858	40,171	N/A	40,171	343,034	30,000
Total Xcel Energy	96,282	140,690	(198,452)	5,871	144,151	188,542	41,706	161,454	1,102,390	191,453

NSPM
Aggregate Cost
41,706,000

[1] Includes NRG, BMG, Viking, Natro Gas, Utility Engineering, Seren, Quixx, Crockett and QPS
[2] Includes Eloigne

Assumptions

Discount Rate - U.S. GAAP	
XEPP	4.03%
NCE	3.58%
SPS	4.17%
PSCo	4.09%
Discount Rate - Aggregate Cost	7.25%
Salary Scale	3.75%
Expected Return on Assets	
XEPP	7.25%
NCE	7.10%
SPS	6.35%
PSCo	6.35%
Assumed Mortality Table	
Bargaining Participants	RP-2000 Blue Collar projected with scale AA to 2013 for all participants
Non-bargaining Participants	RP-2000 White Collar projected with scale AA to 2013 for all participants

Recognized Cost: Total U.S. GAAP cost, excluding Minnesota and Xcel Energy Nuclear, plus aggregate normal cost allocated to Minnesota and Xcel Energy Nuclear.

See February 7, 2013 letter for additional information on data, assumptions, methods and plan provisions.
Contributions already made are allocated in accordance with the January 8, 2013 contribution directives provided by Xcel Energy.

2/7/2013
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WELLS FARGO

FD411
DETAIL STATEMENT OF
CONTRIBUTIONS AND OTHER RECEIPTS

XCEL - TOTAL PENSION PLAN COMPOSITE
BASE CURRENCY: USD

PAGE 325
DECEMBER 31,2013
THROUGH DECEMBER 31,2014

DATE	DESCRIPTION	
CONTRIBUTIONS		
EMPLOYER CONTRIBUTION		
01/14/14	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION DISC OPS	3,689,000.00
01/14/14	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPM - 47,523,000 AND XCEL NUCLEAR - 4,575,000	47,523,000.00
01/14/14	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPM - 47,523,000 AND XCEL NUCLEAR - 4,575,000	4,575,000.00
01/14/14	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPW	8,030,000.00
01/14/14	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION XCEL SERVICES	26,161,000.00
01/14/14	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION XEPC	22,000.00
06/30/14	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION DISC OPS	22.00
06/30/14	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPM AND NUCLEAR	279.00
06/30/14	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPM AND NUCLEAR	27.00
06/30/14	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPW	47.00

Total NSPM Conribution
$ 47,523,000
$ 4,575,000
$ 279
$ 27
$ 15,082
$ 1,456
$ 52,114,844

WELLS FARGO

FD411
DETAIL STATEMENT OF
CONTRIBUTIONS AND OTHER RECEIPTS

XCEL - TOTAL PENSION PLAN COMPOSITE
BASE CURRENCY: USD

PAGE 326
DECEMBER 31,2013
THROUGH DECEMBER 31,2014

DATE	DESCRIPTION	
07/01/14	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION XCEL SERVICES	154.00
12/01/14	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION DISC OPS	1,175.00
12/01/14	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPM AND XCEL NUCLEAR	15,082.00
12/01/14	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPM AND XCEL NUCLEAR	1,456.00
12/01/14	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPW	2,551.00
12/01/14	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION XCEL SERVICES	8,325.00
12/01/14	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION XEPC	7.00
	TOTAL EMPLOYER CONTRIBUTION	90,029,125.00
	TOTAL CONTRIBUTIONS	90,029,125.00

XCEL ENERGY INC. - Qualified Pension Plans
Cost Estimates by Legal Entity
($ in Thousands)

EXHIBIT I
Page 1 of 6

				Amortizations						
2014	Service Cost	Interest Cost	Expected Return on Assets	Prior Service Cost	Net (Gain)/Loss	Net Cost	Aggregate Cost Compensation Method	Aggregate Cost 20-year Amortization Method	January 1 Prepaid (Accrued)	Contribution
Xcel Energy Pension Plan (XEPP)										
Discontinued Operations[1]	-	3,485	(4,660)	-	3,668	2,493	N/A	N/A	34,644	3,689
Xcel Energy Nuclear	6,876	4,227	(5,633)	44	1,078	6,592	3,426	2,428	(1,632)	4,575
NSP - MN	22,823	43,082	(57,287)	892	43,707	53,217	35,485	25,147	407,285	47,523
NSP - WI	4,527	7,257	(9,642)	111	6,617	8,870	N/A	N/A	58,556	8,030
Xcel Services[2]	20,993	24,087	(32,085)	245	13,749	26,989	N/A	N/A	88,822	26,161
XEPC (former EMI)	-	21	(28)	-	(14)	(21)	N/A	N/A	(263)	22
Total XEPP	55,219	82,159	(109,335)	1,292	68,805	98,140	38,911	27,575	587,412	90,000
NCE Non-Bargaining Pension Plan										
Discontinued Operations - Cheyenne	-	159	(222)	-	190	127	N/A	N/A	1,447	179
PSCo	6,264	9,110	(12,726)	136	5,079	7,863	N/A	N/A	16,520	10,390
SPS	3,122	3,905	(5,460)	54	5,351	6,972	N/A	N/A	43,365	4,431
Total NCE	9,386	13,174	(18,408)	190	10,620	14,962	N/A	N/A	61,332	15,000
SPS Bargaining Plan										
SPS	6,062	16,539	(20,719)	-	7,975	9,857	N/A	N/A	124,408	-
Total SPS	6,062	16,539	(20,719)	-	7,975	9,857	N/A	N/A	124,408	-
PSCo Bargaining Plan										
Discontinued Operations - Cheyenne	-	580	(760)	-	549	369	N/A	N/A	7,031	328
PSCo	17,675	44,167	(57,983)	(3,228)	28,813	29,444	N/A	N/A	326,103	24,672
Total PSCo	17,675	44,747	(58,743)	(3,228)	29,362	29,813	N/A	N/A	333,134	25,000
Total Xcel Energy	88,342	156,619	(207,205)	(1,746)	116,762	152,772	38,911	27,575	1,106,286	130,000

NSPM Aggregate Cost
41,706,000

[1] Includes NRG, BMG, Viking, Natro Gas, Utility Engineering, Seren, Quixx, Crockett and QPS
[2] Includes Eloigne

Assumptions

Discount Rate - U.S. GAAP	
XEPP	4.74%
NCE	4.32%
SPS	5.00%
PSCo	4.89%
Discount Rate - Aggregate Normal Cos	7.25%
Salary Scale	3.75%
Expected Return on Assets	
XEPP	7.25%
NCE	7.10%
SPS	6.85%
PSCo	6.75%
Assumed Mortality Table	
Bargaining Participants	RP-2000 Blue Collar projected with scale AA to 2021 for retirees and 2029 for other participants
Non-bargaining Participants	RP-2000 White Collar projected with scale AA to 2021 for retirees and 2029 for other participants

See May 7, 2014 letter for additional information on data, assumptions, methods and plan provisions.
Contributions already made are allocated in accordance with the January 14, 2014 contribution directives provided by Xcel Energy.

5/7/2014
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FD411
DETAIL STATEMENT OF
CONTRIBUTIONS AND OTHER RECEIPTS

XCEL - TOTAL PENSION PLAN COMPOSITE
BASE CURRENCY: USD

PAGE 648
THROUGH DECEMBER 31,2014
DECEMBER 31,2015

DATE	DESCRIPTION	
CONTRIBUTIONS		
EMPLOYER CONTRIBUTION		
01/15/15	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION DISC OPS	2,543,000.00
01/15/15	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPM AND XCEL NUCLEAR	29,693,000.00
01/15/15	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPM AND XCEL NUCLEAR	3,010,000.00
01/15/15	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPW	4,927,000.00
01/15/15	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION XCEL SERVICES	17,811,000.00
01/15/15	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION XEPC	16,000.00
07/02/15	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION DISC OPS	1,694.00
07/02/15	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPM AND XCEL NUCLEAR	19,782.00
07/02/15	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPM AND XCEL NUCLEAR	2,005.00
07/02/15	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPW	3,282.00

Total NSPM Conribution
$ 29,693,000
$ 3,010,000
$ 19,782
$ 2,005
$ 8,920
$ 904
$ 32,734,611

WELLS FARGO

MENT OF
S AND OTHER RECEIPTS

XCEL - TOTAL PENSION PLAN COMPOSITE
BASE CURRENCY: USD

PAGE 649
THROUGH DECEMBER 31,2014
DECEMBER 31,2015

DATE	DESCRIPTION	
07/02/15	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION XCEL SERVICES	11,865.00
07/02/15	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION XEPC	10.00
12/08/15	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION DISC OPS	764.00
12/08/15	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPM AND XCEL NUCLEAR	8,920.00
12/08/15	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPM AND XCEL NUCLEAR	904.00
12/08/15	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPW	1,480.00
12/08/15	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION XCEL SERVICES	5,350.00
12/08/15	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION XEPC	5.00
	TOTAL EMPLOYER CONTRIBUTION	58,056,061.00
	TOTAL CONTRIBUTIONS	58,056,061.00

XCEL ENERGY INC. - Qualified Pension Plans
Benefit Cost Estimates by Legal Entity
($ in Thousands)

EXHIBIT I
Page 1 of 6

2015	Service Cost	Interest Cost	Expected Return on Assets	Amortizations: Prior Service Cost	Amortizations: Net (Gain)/Loss	Net Cost	Aggregate Cost Compensation Method	Aggregate Cost 20-year Amortization Method	January 1 Prepaid (Accrued)[1]	Contribution	PBO
Xcel Energy Pension Plan (XEPP)											
Discontinued Operations[2]	-	3,382	(4,924)	-	3,994	2,452	N/A	N/A	35,842	2,543	85,512
Xcel Energy Nuclear	7,270	4,004	(5,829)	44	1,239	6,728	3,149	2,401	(3,648)	3,010	101,201
NSP - MN	24,286	39,210	(57,001)	892	44,953	52,340	31,064	23,689	401,607	29,693	998,470
NSP - WI	4,759	6,520	(9,483)	111	6,804	8,711	N/A	N/A	57,718	4,927	165,669
Xcel Services[3]	23,730	23,646	(34,416)	245	15,943	29,148	N/A	N/A	92,732	17,811	598,887
XEPC (former EMI)	-	21	(31)	-	(9)	(19)	N/A	N/A	(220)	16	528
Total XEPP	60,045	76,783	(111,684)	1,292	72,924	99,360	34,213	26,090	584,031	58,000	1,950,267
NCE Non-Bargaining Pension Plan											
Discontinued Operations - Cheyenne	-	158	(250)	-	188	96	N/A	N/A	1,499	203	4,261
PSCo	5,830	7,908	(12,511)	92	4,594	5,913	N/A	N/A	16,458	10,170	213,403
SPS	3,459	3,602	(5,701)	39	4,657	6,056	N/A	N/A	38,696	4,627	97,098
Total NCE	9,289	11,668	(18,462)	131	9,439	12,065	N/A	N/A	56,653	15,000	314,762
SPS Bargaining Plan											
SPS	7,547	16,582	(22,909)	-	10,430	11,650	N/A	N/A	114,985	7,000	403,592
Total SPS	7,547	16,582	(22,909)	-	10,430	11,650	N/A	N/A	114,985	7,000	403,592
PSCo Bargaining Plan											
Discontinued Operations - Cheyenne	-	542	(756)	-	576	362	N/A	N/A	6,991	126	13,577
PSCo	22,430	42,949	(60,079)	(3,228)	31,783	33,855	N/A	N/A	321,416	9,874	1,064,554
Total PSCo	22,430	43,491	(60,835)	(3,228)	32,359	34,217	N/A	N/A	328,407	10,000	1,078,131
Total Xcel Energy	99,311	148,524	(213,890)	(1,805)	125,152	157,292	34,213	26,090	1,084,076	90,000	3,746,752

[1] Includes $4,730 transfer from NCE to XEPP for non-de minimis asset transfer on December 31, 2014
[2] Includes NRG, BMG, Viking, Natro Gas, Utility Engineering, Seren, Quixx, Crockett and QPS
[3] Includes Eloigne

NSPM Aggregate Cost
34,213,000

Assumptions

Discount Rate - ASC 715	
XEPP	4.09%
NCE	3.84%
SPS	4.21%
PSCo	4.15%
Discount Rate - Aggregate Normal Cost	7.25%
Salary Scale	3.75%
Expected Return on Assets	
XEPP	7.25%
NCE	7.10%
SPS	7.25%
PSCo	6.75%
Assumed Mortality Table	
Bargaining Participants	RP-2014 Blue Collar projected with generational mortality improvements using an adjusted SOA MP-2014 methodology
Non-bargaining Participants	RP-2014 White Collar, as adjusted for 2014 Xcel Energy mortality study, projected with generational mortality improvements using an adjusted SOA MP-2104 methodology

See February 2, 2015 letter for additional information on data, assumptions, methods and plan provisions.
Contributions already made are allocated in accordance with the January 15, 2015 contribution directives provided by Xcel Energy on January 12, 2015.

WELLS FARGO

FD411
DETAIL STATEMENT OF
CONTRIBUTIONS AND OTHER RECEIPTS

XCEL - TOTAL PENSION PLAN COMPOSITE
BASE CURRENCY: USD

PAGE 1.046
DECEMBER 31,2015
THROUGH DECEMBER 31,2016

DATE	DESCRIPTION	
CONTRIBUTIONS		
EMPLOYER CONTRIBUTION		
01/04/16	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION DISC OPS	3,805,000.00
01/04/16	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPM AND XCEL NUCLEAR	44,773,000.00
01/04/16	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPM AND XCEL NUCLEAR	4,629,000.00
01/04/16	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPW	7,436,000.00
01/04/16	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION XCEL SERVICES	29,333,000.00
01/04/16	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION XEPC	24,000.00
12/06/16	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION DISC OPS	2,119.00
12/06/16	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPM	25,109.00
12/06/16	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPW	4,126.00
12/06/16	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION XCEL NUCLEAR	2,566.00

Total NSPM Conribution	
$	44,773,000
$	4,629,000
$	25,109
$	2,566
$	49,429,675

XCEL ENERGY INC. - Qualified Pension Plans
Benefit Cost by Legal Entity
($ in Thousands)

EXHIBIT I
Page 1 of 6

2016	Service Cost	Interest Cost	Expected Return on Assets	Amortizations: Prior Service Cost	Amortizations: Net (Gain)/Loss	Net Cost	Aggregate Cost Compensation Method	Aggregate Cost 20-year Amortization Method	January 1 Prepaid (Accrued)1	Contribution	PBO
Xcel Energy Pension Plan (XEPP)											
Discontinued Operations[2]	-	3,510	(4,715)	-	3,353	2,148	N/A	N/A	35,936	3,805	78,354
Xcel Energy Nuclear	6,523	4,246	(5,706)	44	559	5,666	3,150	2,608	(7,363)	4,629	94,849
NSP - MN	21,784	41,185	(55,238)	892	36,218	44,841	30,831	25,528	378,989	44,773	928,274
NSP - WI	4,417	6,816	(9,157)	111	5,392	7,579	N/A	N/A	53,939	7,436	152,545
Xcel Services[3]	23,328	26,949	(36,170)	245	12,661	27,013	N/A	N/A	85,540	29,333	605,484
XEPC (former EMI)	-	22	(30)	-	(7)	(15)	N/A	N/A	(185)	24	495
Total XEPP	56,052	82,728	(111,016)	1,292	58,176	87,232	33,981	28,136	546,856	90,000	1,860,001
NCE Non-Bargaining Pension Plan											
Discontinued Operations - Cheyenne	-	170	(232)	-	157	95	N/A	N/A	1,606	133	3,948
PSCo	5,196	8,803	(12,001)	1	3,503	5,502	N/A	N/A	19,102	6,906	205,036
SPS	3,087	3,770	(5,141)	-	3,421	5,137	N/A	N/A	34,788	2,961	87,644
Total NCE	8,283	12,743	(17,374)	1	7,081	10,734	N/A	N/A	55,496	10,000	296,628
SPS Bargaining Plan											
SPS	6,674	17,489	(22,461)	-	8,565	10,267	N/A	N/A	110,335	15,000	379,750
Total SPS	6,674	17,489	(22,461)	-	8,565	10,267	N/A	N/A	110,335	15,000	379,750
PSCo Bargaining Plan											
Discontinued Operations - Cheyenne	-	540	(680)	-	449	309	N/A	N/A	6,755	115	11,934
PSCo	20,730	46,602	(58,768)	(3,212)	23,268	28,620	N/A	N/A	297,435	9,885	1,019,820
Total PSCo	20,730	47,142	(59,448)	(3,212)	23,717	28,929	N/A	N/A	304,190	10,000	1,031,754
Total Xcel Energy	91,739	160,102	(210,299)	(1,919)	97,539	137,162	33,981	28,136	1,016,877	125,000	3,568,133

[1] Includes $4,128 transfer from NCE to XEPP for non-de minimis asset transfer on December 31, 2015
[2] Includes NRG, BMG, Viking, Natro Gas, Utility Engineering, Seren, Quixx, Crockett and QPS
[3] Includes Eloigne

NSPM Aggregate Cost
33,981,000

Assumptions

Discount Rate - U.S. GAAP	
XEPP	4.64%
NCE	4.48%
SPS	4.73%
PSCo	4.71%
Discount Rate - Aggregate Normal Cost	7.10%
Salary Scale	4.00%
Expected Return on Assets	
XEPP	7.10%
NCE	6.90%
SPS	6.75%
PSCo	6.50%
Assumed Mortality Table	
Bargaining Participants	RP-2014 Blue Collar projected with generational mortality improvements using an adjusted SOA MP-2014 methodology
Non-bargaining Participants	RP-2014 White Collar, as adjusted for 2014 Xcel Energy mortality study, projected with generational mortality improvements using an adjusted SOA MP-2014 methodology

See May 13, 2016 letter for additional information on data, assumptions, methods, and plan provisions.
Contributions already made are allocated in accordance with the January 4, 2016 contribution directives provided by Xcel Energy on January 26, 2016.

WELLS FARGO

ENT OF
AND OTHER RECEIPTS

XCEL - TOTAL PENSION PLAN COMPOSITE
BASE CURRENCY: USD

PAGF 76
DECEMBER 31,2016
THROUGH DECEMBER 31,2017

DATE	DESCRIPTION	
CONTRIBUTIONS		
EMPLOYER CONTRIBUTION		
01/03/17	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION DISC OPS	4,569,000.00
01/03/17	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPM	53,700,000.00
01/03/17	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPW	8,963,000.00
01/03/17	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION XCEL NUCLEAR	5,711,000.00
01/03/17	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION XCEL SERVICES	37,024,000.00
01/03/17	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION XEPC	33,000.00
12/04/17	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION	1,467.00
12/04/17	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION	6,138.00
12/04/17	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION	916.00
12/04/17	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION	721.00
12/04/17	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION	8,739.00
12/04/17	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION	5.00

Total NSPM Conribution
$ 53,700,000
$ 5,711,000
$ 319,000
$ 1,001,000
$ 9,655
$ 7,040,655

$ 916	
$ 8,739	
$ 9,655	See below for support that total was NSPM plan contribution

WELLS FARGO

ENT OF
AND OTHER RECEIPTS

XCEL - TOTAL PENSION PLAN COMPOSITE
BASE CURRENCY: USD

PAGF 77
DECEMBER 31,2016
THROUGH DECEMBER 31,2017

DATE	DESCRIPTION	
12/28/17	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPM	319,000.00
12/28/17	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPW	320,000.00
12/28/17	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION XCEL NUCLEAR	1,001,000.00
12/28/17	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION XCEL SERVICES	8,650,000.00
	TOTAL EMPLOYER CONTRIBUTION	120,307,986.00
	TOTAL CONTRIBUTIONS	120,307,986.00

WELLS FARGO

Intraday Composite Report

Custom

As of 12/01/2017

CUSTOMER ID: XCELE402
OPERATOR ID: SEING402

XCEL ENERGY INC.
12/01/2017 04:17 PM ET

Commercial Electronic Office® **Treasury Information Reporting**

WELLS FARGO BANK, N.A.
NSPMN-NORTHERN STATES POWER-MN

Debit Transactions

12/1/2017 506 / BOOK TRANSFER DEBIT **Debit Amount:** 9,655.00
Cust Ref: COMPLETE **Bank Ref:**
Unique ID: RG171201121753
Wells Ref: 171201121753
000000000840245 WELLS FARGO BANK NA TRUST WIRE CLEARING ACCOUNT 550 S 4TH STREET 14TH FLOOR MI
NNEAPOLIS MN 55415 EC17120130077106 ORG=Xcel Energy 414 Nicollet Mall Minneapolis MN 55 401 US
A RFB=00378035 OBI=XEPP PLAN CONTRIBUTION Attn: LeAnn Grathwohl /FTR/ BNF=D 000000000840245 Tr
ust Wire Clearing
Completed Timestamp 171201121233 (Time Released)

Account Net Amount **-9,655.00**

XCEL ENERGY INC. - Qualified Pension Plans
Benefit Cost by Legal Entity
($ in Thousands)

EXHIBIT I
Page 1 of 6

2017	Service Cost	Interest Cost	Expected Return on Assets	Amortizations: Prior Service Cost	Amortizations: Net (Gain)/Loss	Net Cost	Aggregate Cost Compensation Method	Aggregate Cost 20-year Amortization Method	January 1 Prepaid (Accrued)	Contribution	PBO
Xcel Energy Pension Plan (XEPP)											
Discontinued Operations[1]	-	3,070	(4,547)	-	3,676	2,199	N/A	N/A	37,594	4,569	77,403
Xcel Energy Nuclear	6,578	3,905	(5,777)	44	748	5,498	3,308	2,743	(8,397)	5,711	98,345
NSP - MN	21,253	36,802	(54,289)	1,016	38,861	43,643	31,554	26,166	378,945	53,700	938,163
NSP - WI	4,618	6,218	(9,180)	138	5,846	7,640	N/A	N/A	53,800	8,963	157,457
Xcel Services[2]	24,702	25,913	(38,193)	245	15,589	28,256	N/A	N/A	95,517	37,024	658,883
XEPC (former EMI)	-	22	(32)	-	(3)	(13)	N/A	N/A	(146)	33	537
Total XEPP	57,151	75,930	(112,018)	1,443	64,717	87,223	34,862	28,909	557,313	110,000	1,930,788
NCE Non-Bargaining Pension Plan											
Discontinued Operations - Cheyenne	-	155	(226)	-	174	103	N/A	N/A	1,645	132	4,117
PSCo	4,828	7,769	(11,356)	1	3,937	5,179	N/A	N/A	16,497	6,883	204,341
SPS	3,008	3,333	(4,871)	-	3,278	4,748	N/A	N/A	28,980	2,985	87,994
Total NCE	7,836	11,257	(16,453)	1	7,389	10,030	N/A	N/A	47,122	10,000	296,452
SPS Bargaining Plan											
SPS	6,750	16,377	(23,012)	-	9,703	9,818	N/A	N/A	115,195	20,000	395,607
Total SPS	6,750	16,377	(23,012)	-	9,703	9,818	N/A	N/A	115,195	20,000	395,607
PSCo Bargaining Plan											
Discontinued Operations - Cheyenne	-	456	(608)	-	454	302	N/A	N/A	6,561	111	11,290
PSCo	22,452	42,789	(57,179)	(3,212)	24,418	29,268	N/A	N/A	278,738	9,889	1,047,481
Total PSCo	22,452	43,245	(57,787)	(3,212)	24,872	29,570	N/A	N/A	285,299	10,000	1,058,771
Total Xcel Energy	94,189	146,809	(209,270)	(1,768)	106,681	136,641	34,862	28,909	1,004,929	150,000	3,681,618

[1] Includes NRG, BMG, Viking, Natro Gas, Utility Engineering, Seren, Quixx, Crockett and QPS
[2] Includes Eloigne

Assumptions	
Discount Rate - U.S. GAAP	
XEPP	4.11%
NCE	3.97%
SPS	4.25%
PSCo	4.21%
Discount Rate - Aggregate Normal Cost	7.10%
Salary Scale	3.75%
Expected Return on Assets	
XEPP	7.10%
NCE	6.90%
SPS	6.75%
PSCo	6.50%
Assumed Mortality Table	
Bargaining Participants	RP-2014 Blue Collar projected with generational mortality improvements using an adjusted SOA MP-2016 methodology
Non-bargaining Participants	RP-2014 White Collar, as adjusted for 2014 Xcel Energy mortality study, projected with generational mortality improvements using an adjusted SOA MP-2016 methodology

See May 17, 2017 letter for additional information on data, assumptions, methods and plan provisions.
Contributions already made are allocated in accordance with the January 3, 2017 contribution directives provided by Xcel Energy on January 23, 2017.

NSPM Aggregate Cost
34,862,000

WELLS FARGO

FD411
DETAIL STATEMENT OF
CONTRIBUTIONS AND OTHER RECEIPTS

XCEL - TOTAL PENSION PLAN COMPOSITE
BASE CURRENCY: USD

PAGE 44
DECEMBER 31,2017
THROUGH DECEMBER 31,2018

DATE	DESCRIPTION	
CONTRIBUTIONS		
EMPLOYER CONTRIBUTION		
01/02/18	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION	56,623,000.00
01/02/18	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION	9,597,000.00
01/02/18	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION	42,356,000.00
01/02/18	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION	36,000.00
01/02/18	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION	6,524,000.00
01/02/18	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION	4,864,000.00
	TOTAL EMPLOYER CONTRIBUTION	120,000,000.00
	TOTAL CONTRIBUTIONS	120,000,000.00

Total NSPM Conribution	
$ 56,623,000	
$ 6,524,000	
$ 63,147,000	See below for support that total was NSPM plan contribution

WELLS FARGO

Intraday Composite Report

Custom

As of 01/02/2018

CUSTOMER ID: XCELE402
OPERATOR ID: SEING402

XCEL ENERGY INC.
01/02/2018 02:52 PM ET

Commercial Electronic Office® **Treasury Information Reporting**

WELLS FARGO BANK, N.A.
NSPMN-NORTHERN STATES POWER-MN

Debit Transactions

1/2/2018

506 / BOOK TRANSFER DEBIT
Cust Ref: COMPLETE
Unique ID: RG180102130080
Wells Ref: 180102130080
000000000840245 WELLS FARGO BANK NA TRUST WIRE CLEARING ACCOUNT 550 S 4TH STREET 14TH FLOOR MI
NNEAPOLIS MN 55415 EC18010264770578 ORG=Xcel Energy 414 Nicollet Mall Minneapolis MN 55 401 US
A RFB=00387346 OBI=OBI: XEPP Plan Contribution - NSPMN /FTR/ BNF=D 000000000840245 Trust Wire
Clearing
Completed Timestamp 180102124216 (Time Released)

Debit Amount: 63,147,000.00
Bank Ref:

Account Net Amount **-63,147,000.00**

XCEL ENERGY INC. - Qualified Pension Plans
Cost by Legal Entity
($ in Thousands)

EXHIBIT I
Page 1 of 6

2018	Service Cost	Interest Cost	Expected Return on Assets	Amortizations: Prior Service Cost	Amortizations: Net (Gain)/Loss	Net Cost	Settlement Charge [1]	Aggregate Cost Compensation Method	Aggregate Cost 20-year Amortization Method	January 1 Prepaid (Accrued)	Contribution	PBO
Xcel Energy Pension Plan (XEPP)												
Discontinued Operations[2]	-	2,736	(4,539)	-	3,615	1,812	-	N/A	N/A	35,418	4,864	78,815
Xcel Energy Nuclear	6,284	3,738	(6,200)	(214)	1,129	4,737	-	3,574	3,042	(9,131)	6,524	107,357
NSP - MN	21,644	31,479	(51,967)	100	37,329	38,585	-	30,891	26,292	342,488	56,623	927,782
NSP - WI	4,777	5,442	(9,025)	(30)	5,673	6,837	-	N/A	N/A	48,153	9,597	156,748
Xcel Services[3]	22,849	23,771	(39,361)	(985)	17,078	23,352	-	N/A	N/A	87,739	42,356	690,963
XEPC (former EMI)	-	21	(34)	-	2	(11)	-	N/A	N/A	(101)	36	584
Total XEPP	55,554	67,187	(111,126)	(1,129)	64,826	75,312	-	34,465	29,334	504,566	120,000	1,962,249
NCE Non-Bargaining Pension Plan												
Discontinued Operations - Cheyenne	-	133	(218)	-	177	92	-	N/A	N/A	1,675	137	3,931
PSCo	4,297	6,958	(11,341)	(165)	4,403	4,152	-	N/A	N/A	18,891	6,830	206,586
SPS	2,656	3,045	(4,957)	(137)	3,386	3,993	-	N/A	N/A	27,599	3,033	91,051
Total NCE	6,953	10,136	(16,516)	(302)	7,966	8,237	-	N/A	N/A	48,165	10,000	301,568
SPS Bargaining Plan												
SPS	7,062	15,365	(23,370)	-	10,682	9,739	-	N/A	N/A	125,403	5,000	424,828
Total SPS	7,062	15,365	(23,370)	-	10,682	9,739	-	N/A	N/A	125,403	5,000	424,828
PSCo Bargaining Plan												
Discontinued Operations - Cheyenne	-	404	(571)	-	469	302	-	N/A	N/A	6,370	150	11,411
PSCo	24,788	40,296	(57,179)	(3,212)	26,855	31,548	-	N/A	N/A	259,393	14,850	1,127,594
Total PSCo	24,788	40,700	(57,750)	(3,212)	27,324	31,850	-	N/A	N/A	265,763	15,000	1,139,005
Total Xcel Energy	94,357	133,388	(208,762)	(4,643)	110,798	125,138	-	34,465	29,334	943,897	150,000	3,827,650

[1] Settlement accounting may be required if lump sum benefit payments exceed the sum of service cost and interest on a plan by plan basis. No settlements have been estimated at this time.
[2] Includes NRG, BMG, Viking, Natro Gas, Utility Engineering, Seren, Quixx, Crockett and QPS
[3] Includes Eloigne

NSPM Aggregate Cost
34,465,000

Assumptions

Discount Rate - U.S. GAAP	
XEPP	3.60%
NCE	3.52%
SPS	3.71%
PSCo	3.68%
Discount Rate - Aggregate Normal Cost	7.10%
Salary Scale	3.75%
Expected Return on Assets	
XEPP	7.10%
NCE	6.90%
SPS	6.75%
PSCo	6.50%
Assumed Mortality Table	
Bargaining Participants	RP-2014 Blue Collar projected with generational mortality improvements using an adjusted SOA MP-2016 methodology
Non-bargaining Participants	RP-2014 White Collar, as adjusted for 2014 Xcel Energy mortality study, projected with generational mortality improvements using an adjusted SOA MP-2016 methodology

See May 18, 2018 letter for additional information on data, assumptions, methods, and plan provisions.
Contributions already made are allocated in accordance with the January 2, 2018 contribution directives provided by Xcel Energy on January 3, 2018.

MENT OF
S AND OTHER RECEIPTS

XCEL - TOTAL PENSION PLAN COMPOSITE
BASE CURRENCY: USD

PAGE 48
DECEMBER 31,2018
THROUGH DECEMBER 31,2019

DATE	DESCRIPTION	
CONTRIBUTIONS		
EMPLOYER CONTRIBUTION		
01/02/19	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION DISC OPS	3,785,000.00
01/02/19	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPM / XCEL NUCLEAR	41,669,000.00
01/02/19	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPM / XCEL NUCLEAR	5,052,000.00
01/02/19	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPW	7,239,000.00
01/02/19	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION XCEL SERVICES	32,227,000.00
01/02/19	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION XEPC	28,000.00
12/03/19	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION XCEL ENERGY PERFORMANCE CONTRACTING CASH PROCESSES	58.00
12/06/19	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION	14,924.00
12/06/19	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION	86,154.00
12/06/19	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION	10,701.00
12/06/19	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION	7,890.00
12/06/19	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION	67,546.00

Total NSPM Conribution	
$ 41,669,000	
$ 5,052,000	
$ 96,855	See below for support that total was NSPM plan contribution
$ 46,721,000	

Intraday Composite Report

Custom Intraday Report
As of 12/03/2019
Company: XCEL ENERGY INC.

12/03/2019 01:06 PM ET

Commercial Electronic Office® — **Treasury Information Reporting**

WELLS FARGO BANK, N.A.
NSPMN-NORTHERN STATES POWER-MN

Debit Transactions

12/3/2019 506 / BOOK TRANSFER DEBIT — **Debit Amount:** 96,855.00
Cust Ref: COMPLETE — **Bank Ref:**
Unique ID: RG191203088290
Wells Ref: 191203088290
000000000840245 WELLS FARGO BANK NA TRUST WIRE CLEARING ACCOUNT MAC # N9310-140, 550 S 4TH ST MINNEAPOLIS MN US 55415 EC19120310178385 ORG=Xcel Energy 414 Nicollet Mall Minneapolis MN 55 4 01 USA RFB=00641545 /FTR/ BNF=D 000000000840245 Trust Wire Clearing
Completed Timestamp 191203111708 (Time Released)

XCEL ENERGY INC. - Qualified Pension Plans
Cost by Legal Entity
($ in Thousands)

EXHIBIT I
Page 1 of 6

2019	Service Cost	Interest Cost	Expected Return on Assets	Amortizations Prior Service Cost	Amortizations Net (Gain)/Loss	Net Cost	Settlement Charge [1]	Aggregate Cost Compensation Method	Aggregate Cost 20-year Amortization Method	January 1 Prepaid (Accrued)	Contribution	PBO
Xcel Energy Pension Plan (XEPP)												
Discontinued Operations[2]	-	3,051	(4,468)	-	3,050	1,633	-	N/A	N/A	33,632	3,785	73,890
Xcel Energy Nuclear	5,834	4,153	(6,079)	(214)	630	4,324	-	3,834	3,392	(8,658)	5,052	100,213
NSP - MN	19,598	32,928	(48,176)	100	29,580	34,030	-	30,873	27,312	313,067	41,669	806,830
NSP - WI	4,433	5,709	(8,356)	(30)	4,447	6,203	-	N/A	N/A	43,681	7,239	139,764
Xcel Services[3]	21,737	26,095	(38,200)	(985)	13,112	21,759	-	N/A	N/A	84,737	32,227	632,568
XEPC (former EMI)	-	23	(33)	-	2	(8)	-	N/A	N/A	(58)	28	546
Total XEPP	51,602	71,959	(105,312)	(1,129)	50,821	67,941	-	34,707	30,704	466,401	90,000	1,753,811
NCE Non-Bargaining Pension Plan												
Discontinued Operations - Cheyenne	-	146	(203)	-	146	89	-	N/A	N/A	1,545	65	3,601
PSCo	3,915	7,642	(10,625)	(165)	3,321	4,088	-	N/A	N/A	17,104	3,434	187,999
SPS	2,431	3,347	(4,645)	(137)	2,608	3,604	-	N/A	N/A	23,427	1,501	83,030
Total NCE	6,346	11,135	(15,473)	(302)	6,075	7,781	-	N/A	N/A	42,076	5,000	274,630
SPS Bargaining Plan												
SPS	6,377	16,788	(23,998)	-	8,741	7,908	-	N/A	N/A	120,664	15,000	394,752
Total SPS	6,377	16,788	(23,998)	-	8,741	7,908	-	N/A	N/A	120,664	15,000	394,752
PSCo Bargaining Plan												
Discontinued Operations - Cheyenne	-	416	(547)	-	421	290	-	N/A	N/A	6,218	386	9,963
PSCo	21,667	43,985	(57,881)	(3,212)	22,122	26,681	-	N/A	N/A	242,695	39,614	1,041,247
Total PSCo	21,667	44,401	(58,428)	(3,212)	22,543	26,971	-	N/A	N/A	248,913	40,000	1,051,210
Total Xcel Energy	85,992	144,283	(203,211)	(4,643)	88,180	110,601	-	34,707	30,704	878,054	150,000	3,474,403

[1] Settlement accounting may be required if lump sum benefit payments exceed the sum of service cost and interest on a plan by plan basis. No settlements have been estimated at this time.
[2] Includes NRG, BMG, Viking, Natro Gas, Utility Engineering, Seren, Quixx, Crockett and QPS
[3] Includes Eloigne

NSPM Aggregate Cost
34,707,000

Assumptions

Discount Rate - U.S. GAAP	
XEPP	4.31%
NCE	4.25%
SPS	4.37%
PSCo	4.36%
Discount Rate - Aggregate Normal Cost	7.10%
Salary Scale	3.75%
Expected Return on Assets	
XEPP	7.10%
NCE	6.90%
SPS	6.75%
PSCo	6.50%
Assumed Mortality Table	
Bargaining Participants	RP-2014 Blue Collar projected with generational mortality improvements using an adjusted SOA MP-2016 methodology
Non-bargaining Participants	RP-2014 White Collar, as adjusted for 2014 Xcel Energy mortality study, projected with generational mortality improvements using an adjusted SOA MP-2016 methodology

See March 29, 2019 letter for additional information on data, assumptions, methods, and plan provisions.
Contributions already made are allocated in accordance with the January 2, 2019 contribution directives.

WELLS FARGO

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ND OTHER RECEIPTS

XCEL - TOTAL PENSION PLAN COMPOSITE
BASE CURRENCY: USD

PAGE 44
THROUGH DECEMBER 31,2019
DECEMBER 31,2020

DATE	DESCRIPTION	
CONTRIBUTIONS		
EMPLOYER CONTRIBUTION		
01/02/20	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION DISC OPS	3,493,000.00
01/02/20	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPM	39,113,000.00
01/02/20	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPW	6,734,000.00
01/02/20	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION XCEL NUCLEAR	4,846,000.00
01/02/20	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION XCEL SERVICES	30,787,000.00
01/02/20	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION XEPC	27,000.00
	TOTAL EMPLOYER CONTRIBUTION	85,000,000.00
	TOTAL CONTRIBUTIONS	85,000,000.00

Total NSPM Conribution	
$	39,113,000
$	4,846,000
$	43,959,000

XCEL ENERGY INC. - Qualified Pension Plans
Cost by Legal Entity
($ in Thousands)

EXHIBIT I
Page 1 of 6

2020	Service Cost	Interest Cost	Expected Return on Assets	Amortizations: Prior Service Cost	Amortizations: Net (Gain)/Loss	Net Cost	Settlement Charge [1]	Aggregate Cost Compensation Method	Aggregate Cost 20-year Amortization Method	January 1 Prepaid (Accrued)	Contribution	PBO
Xcel Energy Pension Plan (XEPP)												
Discontinued Operations[2]	-	2,572	(4,525)	-	3,345	1,392	-	N/A	N/A	35,792	3,493	76,854
Xcel Energy Nuclear	5,830	3,543	(6,236)	(214)	874	3,797	-	3,529	3,222	(7,919)	4,846	105,931
NSP - MN	21,118	27,680	(48,698)	179	31,625	31,904	-	27,855	25,437	320,792	39,113	836,251
NSP - WI	4,723	4,790	(8,441)	(24)	4,764	5,812	-	N/A	N/A	44,732	6,734	143,385
Xcel Services[3]	23,511	22,522	(39,614)	(985)	15,191	20,625	-	N/A	N/A	95,273	30,787	675,394
XEPC (former EMI)	-	21	(35)	-	7	(7)	-	N/A	N/A	(22)	27	714
Mankato Energy Center[4]	78	-	-	-	-	78	-	N/A	N/A	-	78	-
Total XEPP	55,260	61,128	(107,549)	(1,044)	55,806	63,601	-	31,384	28,659	488,648	85,078	1,838,529
NCE Non-Bargaining Pension Plan												
Discontinued Operations - Cheyenne	-	116	(200)	-	151	67	-	N/A	N/A	1,426	193	3,579
PSCo	3,875	6,204	(10,688)	(165)	3,891	3,117	-	N/A	N/A	15,687	10,379	191,074
SPS	2,484	2,632	(4,525)	(137)	2,639	3,093	-	N/A	N/A	20,024	4,428	81,928
Total NCE	6,359	8,952	(15,413)	(302)	6,681	6,277	-	N/A	N/A	37,137	15,000	276,581
SPS Bargaining Plan												
SPS	7,148	15,243	(24,816)	-	10,477	8,052	-	N/A	N/A	127,961	10,000	436,854
Total SPS	7,148	15,243	(24,816)	-	10,477	8,052	-	N/A	N/A	127,961	10,000	436,854
PSCo Bargaining Plan												
Discontinued Operations - Cheyenne	-	351	(529)	-	448	270	-	N/A	N/A	6,314	354	10,217
PSCo	26,603	39,586	(59,815)	(2,650)	25,984	29,708	-	N/A	N/A	255,652	39,646	1,138,688
Total PSCo	26,603	39,937	(60,344)	(2,650)	26,432	29,978	-	N/A	N/A	261,966	40,000	1,148,905
Total Xcel Energy	95,370	125,260	(208,122)	(3,996)	99,396	107,908	-	31,384	28,659	915,712	150,078	3,700,869

NSPM Aggregate Cost
31,384,000

[1] Settlement accounting may be required if lump sum benefit payments exceed the sum of service cost and interest on a plan by plan basis. No settlements have been estimated at this time.
[2] Includes NRG, BMG, Viking, Natro Gas, Utility Engineering, Seren, Quixx, Crockett and QPS
[3] Includes Eloigne
[4] Cost reflects final census data. See May 15, 2020 letter for additional details.

Assumptions

Discount Rate - U.S. GAAP	
XEPP	3.48%
NCE	3.39%
SPS	3.58%
PSCo	3.58%
Discount Rate - Aggregate Normal Cost	7.10%
Salary Scale	3.75%
Expected Return on Assets	
XEPP	7.10%
NCE	6.90%
SPS	6.75%
PSCo	6.50%
Assumed Mortality Table	
Bargaining Participants	Pri-2012 Blue Collar, as adjusted for 2019 Xcel Energy mortality study, projected with generational mortality improvements using an adjusted SOA MP-2019 methodology
Non-bargaining Participants	Pri-2012 White Collar, as adjusted for 2019 Xcel Energy mortality study, projected with generational mortality improvements using an adjusted SOA MP-2019 methodology

See May 15, 2020 letter for additional information on data, assumptions, methods, and plan provisions.
Contributions already made are allocated in accordance with the January 2, 2020 contribution directives.

WELLS FARGO

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ND OTHER RECEIPTS

XCEL - TOTAL PENSION PLAN COMPOSITE

BASE CURRENCY: USD

PAGE 44

THROUGH DECEMBER 31,2020
DECEMBER 31,2021

DATE	DESCRIPTION	
CONTRIBUTIONS		
EMPLOYER CONTRIBUTION		
01/04/21	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION DISC OPS	2,649,000.00
01/04/21	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPM	29,346,000.00
01/04/21	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPW	5,182,000.00
01/04/21	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION XCEL NUCLEAR	3,797,000.00
01/04/21	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION XCEL SERVICES	24,009,000.00
01/04/21	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION XEPC	17,000.00
12/28/21	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPM	966,000.00
12/28/21	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPW	114,000.00
12/28/21	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION XCEL SERVICES	4,230,000.00
	TOTAL EMPLOYER CONTRIBUTION	70,310,000.00
	TOTAL CONTRIBUTIONS	70,310,000.00

Total NSPM Conribution
$ 29,346,000
$ 3,797,000
$ 966,000
$ 34,109,000

XCEL ENERGY INC. - Qualified Pension Plans
Cost by Legal Entity
($ in Thousands)

EXHIBIT I
Page 1 of 6

2021	Service Cost	Interest Cost	Expected Return on Assets	Amortizations Prior Service Cost	Amortizations Net (Gain)/Loss	Net Cost	Settlement Charge [1]	Aggregate Cost Compensation Method	Aggregate Cost 20-year Amortization Method	January 1 Prepaid (Accrued)	Contribution	PBO
Xcel Energy Pension Plan (XEPP)												
Discontinued Operations[2]	-	2,044	(4,263)	-	3,553	1,334	-	N/A	N/A	37,850	2,649	80,128
Xcel Energy Nuclear	6,024	2,889	(6,016)	(214)	1,111	3,794	-	3,675	3,365	(6,870)	3,797	114,229
NSP - MN	23,508	21,941	(45,631)	179	32,968	32,965	-	28,136	25,760	328,001	29,346	874,567
NSP - WI	5,244	3,910	(8,150)	(24)	5,028	6,008	-	N/A	N/A	45,654	5,182	154,058
Xcel Services[3]	26,755	18,660	(38,828)	(985)	17,242	22,844	-	N/A	N/A	109,357	24,009	737,012
XEPC (former EMI)	-	14	(28)	-	8	(6)	-	N/A	N/A	12	17	526
Total XEPP	61,531	49,458	(102,916)	(1,044)	59,910	66,939	-	31,811	29,125	514,004	65,000	1,960,520
NCE Non-Bargaining Pension Plan												
Discontinued Operations - Cheyenne	-	88	(200)	-	155	43	-	N/A	N/A	1,552	179	3,665
PSCo	3,829	4,516	(10,292)	(165)	3,877	1,765	-	N/A	N/A	20,196	9,657	188,758
SPS	2,660	2,059	(4,666)	(137)	2,576	2,492	-	N/A	N/A	20,190	4,164	86,992
Total NCE	6,489	6,663	(15,158)	(302)	6,608	4,300	-	N/A	N/A	41,938	14,000	279,415
SPS Bargaining Plan												
SPS	7,869	13,164	(25,026)	-	11,524	7,531	-	N/A	N/A	129,909	10,000	474,732
Total SPS	7,869	13,164	(25,026)	-	11,524	7,531	-	N/A	N/A	129,909	10,000	474,732
PSCo Bargaining Plan												
Discontinued Operations - Cheyenne	-	277	(505)	-	467	239	-	N/A	N/A	6,398	292	10,162
PSCo	28,219	34,128	(62,428)	16	28,702	28,637	-	N/A	N/A	265,590	35,708	1,239,490
Total PSCo	28,219	34,405	(62,933)	16	29,169	28,876	-	N/A	N/A	271,988	36,000	1,249,652
Total Xcel Energy	104,108	103,690	(206,033)	(1,330)	107,211	107,646	-	31,811	29,125	957,839	125,000	3,964,319

NSPM
Aggregate Cost
31,811,000

[1] Settlement accounting may be required if lump sum benefit payments exceed the sum of service cost and interest on a plan by plan basis. No settlements have been estimated at this time.
[2] Includes NRG, BMG, Viking, Natro Gas, Utility Engineering, Seren, Quixx, Crockett, QPS and MEC
[3] Includes Eloigne

Assumptions

Discount Rate - U.S. GAAP	
XEPP	2.65%
NCE	2.50%
SPS	2.84%
PSCo	2.83%
Discount Rate - Aggregate Normal Cost	6.60%
Salary Scale	3.75%
Expected Return on Assets	
XEPP	6.60%
NCE	6.60%
SPS	6.35%
PSCo	6.35%
Assumed Mortality Table	
Bargaining Participants	Pri-2012 Blue Collar, as adjusted for 2019 Xcel Energy mortality study, projected with generational mortality improvements using an adjusted SOA MP-2020 methodology
Non-bargaining Participants	Pri-2012 White Collar, as adjusted for 2019 Xcel Energy mortality study, projected with generational mortality improvements using an adjusted SOA MP-2020 methodology

See May 12, 2021 letter for additional information on data, assumptions, methods, models and plan provisions.
Contributions already made are allocated in accordance with the January 4, 2021 contribution directives.

Principal® Custody Solutions

FD411
DETAIL STATEMENT OF
CONTRIBUTIONS AND OTHER RECEIPTS

XCEL - TOTAL PENSION PLAN COMPOSITE
BASE CURRENCY: USD

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DECEMBER 31,2021
THROUGH DECEMBER 31,2022

DATE	DESCRIPTION	
CONTRIBUTIONS		
EMPLOYER CONTRIBUTION		
01/03/22	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION DISC OPS	411,000.00
01/03/22	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPM	4,375,000.00
01/03/22	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPW	779,000.00
01/03/22	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION XCEL NUCLEAR	532,000.00
01/03/22	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION XCEL SERVICES	3,900,000.00
01/03/22	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION XEPC	3,000.00
	TOTAL EMPLOYER CONTRIBUTION	10,000,000.00
	TOTAL CONTRIBUTIONS	10,000,000.00

Total NSPM Conribution	
$	4,375,000
$	532,000
$	4,907,000

XCEL ENERGY INC. - Qualified Pension Plans
Cost by Legal Entity
($ in Thousands)

EXHIBIT I
Page 1 of 6

2022	Service Cost	Interest Cost	Expected Return on Assets	Amortizations: Prior Service Cost	Amortizations: Net (Gain)/Loss	Net Cost	Settlement Charge [1]	Aggregate Cost Compensation Method	Aggregate Cost 20-year Amortization Method	January 1 Prepaid (Accrued)	Contribution	PBO
Xcel Energy Pension Plan (XEPP)												
Discontinued Operations[2]	-	2,207	(4,202)	-	2,680	685	-	N/A	N/A	35,029	411	74,675
Xcel Energy Nuclear	5,028	2,807	(5,334)	(214)	370	2,657	-	3,003	2,913	(6,689)	532	96,209
NSP - MN	22,030	22,313	(42,291)	179	23,248	25,479	-	24,376	23,649	289,923	4,375	780,985
NSP - WI	4,793	4,092	(7,772)	(24)	3,460	4,549	-	N/A	N/A	39,906	779	140,856
Xcel Services[3]	25,870	20,614	(39,189)	(985)	11,529	17,839	-	N/A	N/A	98,950	3,900	704,838
XEPC (former EMI)	-	15	(28)	-	5	(8)	-	N/A	N/A	30	3	498
Total XEPP	57,721	52,048	(98,816)	(1,044)	41,292	51,201	-	27,379	26,562	457,149	10,000	1,798,061
NCE Non-Bargaining Pension Plan												
Discontinued Operations - Cheyenne	-	97	(191)	-	123	29	-	N/A	N/A	1,688	-	3,382
PSCo	3,547	5,043	(10,295)	(165)	2,470	600	-	N/A	N/A	28,276	-	175,115
SPS	2,543	2,374	(4,840)	(137)	1,726	1,666	-	N/A	N/A	22,069	-	83,587
Total NCE	6,090	7,514	(15,326)	(302)	4,319	2,295	-	N/A	N/A	52,033	-	262,084
SPS Bargaining Plan												
SPS	7,271	14,113	(26,220)	-	8,717	3,881	-	N/A	N/A	132,378	-	461,057
Total SPS	7,271	14,113	(26,220)	-	8,717	3,881	-	N/A	N/A	132,378	-	461,057
PSCo Bargaining Plan												
Discontinued Operations - Cheyenne	-	281	(522)	-	371	130	-	N/A	N/A	6,451	309	9,315
PSCo	25,903	36,244	(67,389)	16	20,041	14,815	-	N/A	N/A	272,661	39,691	1,187,695
Total PSCo	25,903	36,525	(67,911)	16	20,412	14,945	-	N/A	N/A	279,112	40,000	1,197,010
Total Xcel Energy	96,985	110,200	(208,273)	(1,330)	74,740	72,322	-	27,379	26,562	920,672	50,000	3,718,212

NSPM Aggregate Cost
27,379,000

[1] Settlement accounting may be required if lump sum benefit payments exceed the sum of service cost and interest on a plan by plan basis. No settlements have been estimated at this time.
[2] Includes NRG, BMG, Viking, Natro Gas, Utility Engineering, Seren, Quixx, Crockett, QPS and MEC
[3] Includes Eloigne

Assumptions

Discount Rate - U.S. GAAP	
XEPP	3.07%
NCE	3.02%
SPS	3.14%
PSCo	3.14%
Discount Rate - Aggregate Normal Cost	6.60%
Salary Scale	3.75%
Expected Return on Assets	
XEPP	6.60%
NCE	6.60%
SPS	6.35%
PSCo	6.35%
Assumed Mortality Table	
Bargaining Participants	Pri-2012 Blue Collar, as adjusted for 2019 Xcel Energy mortality study, projected with generational mortality improvements using an adjusted SOA MP-2020 methodology
Non-bargaining Participants	Pri-2012 White Collar, as adjusted for 2019 Xcel Energy mortality study, projected with generational mortality improvements using an adjusted SOA MP-2020 methodology

See June 30, 2022 letter for additional information on data, assumptions, methods, models and plan provisions.
Contributions already made are allocated in accordance with the January 3, 2022 contribution directives.

Principal® Custody Solutions

FD411
DETAIL STATEMENT OF CONTRIBUTIONS AND OTHER RECEIPTS

XCEL - TOTAL PENSION PLAN COMPOSITE

BASE CURRENCY: USD

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DECEMBER 31,2022 THROUGH JANUARY 31,2023

DATE	DESCRIPTION	
CONTRIBUTIONS		
EMPLOYER CONTRIBUTION		
01/03/23	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION DISC OPS 12229280	2,000,000.00
01/03/23	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION EXCEL SERVICES 12229280	20,743,000.00
01/03/23	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPM 12229280	20,656,000.00
01/03/23	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION NSPW 12229280	3,965,000.00
01/03/23	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION XCEL NUCLEAR 12229280	2,623,000.00
01/03/23	ADDITION TO ACCOUNT EMPLOYER CONTRIBUTION XEPC 12229280	13,000.00
	TOTAL EMPLOYER CONTRIBUTION	50,000,000.00
	TOTAL CONTRIBUTIONS	50,000,000.00

Total NSPM Conribution	
$	20,656,000
$	2,623,000
$	23,279,000

XCEL ENERGY INC. - Qualified Pension Plans
Cost by Legal Entity
($ in Thousands)

EXHIBIT I
Page 1 of 6

2023	Service Cost	Interest Cost	Expected Return on Assets	Amortizations: Prior Service Cost	Amortizations: Net (Gain)/Loss	Net Cost	Settlement Charge [1]	Aggregate Cost Compensation Method	Aggregate Cost 20-year Amortization Method	January 1 Prepaid (Accrued)	Contribution	PBO
Xcel Energy Pension Plan (XEPP)												
Discontinued Operations[2]	-	3,168	(4,076)	-	1,540	632	-	N/A	N/A	30,165	2,013	57,482
Xcel Energy Nuclear	3,920	4,029	(5,187)	(214)	(360)	2,188	-	3,398	3,411	(9,042)	2,623	73,506
NSP - MN	17,195	31,654	(40,755)	222	11,753	20,069	-	26,979	27,077	231,069	20,656	583,547
NSP - WI	3,791	6,142	(7,906)	(21)	1,585	3,591	-	N/A	N/A	30,575	3,965	111,490
Xcel Services[3]	23,075	32,284	(41,545)	(985)	3,902	16,731	-	N/A	N/A	66,917	20,743	589,576
Total XEPP	47,981	77,277	(99,469)	(998)	18,420	43,211	-	30,377	30,488	349,684	50,000	1,415,601
NCE Non-Bargaining Pension Plan												
Discontinued Operations - Cheyenne	-	134	(166)	-	38	6	-	N/A	N/A	1,525	-	2,445
PSCo	2,925	7,545	(9,438)	(165)	453	1,320	-	N/A	N/A	24,927	-	137,586
SPS	2,214	3,659	(4,583)	(137)	407	1,560	-	N/A	N/A	18,521	-	67,890
Total NCE	5,139	11,338	(14,187)	(302)	898	2,886	-	N/A	N/A	44,973	-	207,921
SPS Bargaining Plan												
SPS	4,778	19,370	(28,281)	-	1,195	(2,938)	-	N/A	N/A	128,497	-	345,723
Total SPS	4,778	19,370	(28,281)	-	1,195	(2,938)	-	N/A	N/A	128,497	-	345,723
PSCo Bargaining Plan												
Discontinued Operations - Cheyenne	-	384	(509)	-	71	(54)	-	N/A	N/A	6,630	-	6,939
PSCo	15,938	50,101	(67,005)	16	1,684	734	-	N/A	N/A	297,537	-	894,432
Total PSCo	15,938	50,485	(67,514)	16	1,755	680	-	N/A	N/A	304,167	-	901,371
Total Xcel Energy	73,836	158,470	(209,451)	(1,284)	22,268	43,839	-	30,377	30,488	827,321	50,000	2,870,616

NSPM
Aggregate Cost
30,377,000

[1] Settlement accounting may be required if lump sum benefit payments exceed the sum of service cost and interest on a plan by plan basis. No settlements have been estimated at this time.
[2] Includes NRG, BMG, Viking, Natro Gas, Utility Engineering, Seren, Quixx, Crockett, QPS, MEC, and XEPC (former EMI)
[3] Includes Eloigne

Assumptions

Discount Rate - U.S. GAAP	
XEPP	5.80%
NCE	5.80%
SPS	5.80%
PSCo	5.82%
Discount Rate - Aggregate Normal Cost	7.25%
Salary Scale	4.25%
Expected Return on Assets	
XEPP	7.25%
NCE	6.75%
SPS	7.00%
PSCo	6.50%
Assumed Mortality Table	
Bargaining Participants	Pri-2012 Blue Collar, as adjusted for 2019 Xcel Energy mortality study, projected with generational mortality improvements using an adjusted SOA MP-2020 methodology
Non-bargaining Participants	Pri-2012 White Collar, as adjusted for 2019 Xcel Energy mortality study, projected with generational mortality improvements using an adjusted SOA MP-2020 methodology

See June 2, 2023 letter for additional information on data, assumptions, methods, models and plan provisions.
Contributions already made are allocated in accordance with the January 3, 2023 contribution directives.

wtw

Schedule 12
2024 Test Year Active Health Care O&M Costs by Category

Allocation Percentages		
Company	MN Gas O&M	MN Gas O&M State of MN
NSPM	8.28%	89.80%
XES	2.55%	89.80%

	NSPM			XES			Totals	
	Total Cost	MN Gas O&M	MN Gas O&M State of MN	Total Cost	MN Gas O&M	MN Gas O&M State of MN	MN Gas O&M	MN Gas O&M State of MN
Misc Benefit Programs & Costs								
Adoption Assistance	2,407	199	179	4,729	121	108	320	287
HR Service Center	14,832	1,228	1,102	977,118	24,946	22,402	26,174	23,505
Communications, Printing & Postage	51,192	4,237	3,805	100,583	2,568	2,306	6,805	6,111
Ergonomists for field workers	-	-	-	120,000	3,064	2,751	3,064	2,751
Return to Work (STD/LTD)	-	-	-	150,000	3,830	3,439	3,830	3,439
Financial Planning	0	-	-	537,820	13,731	12,330	13,731	12,330
Cobra Admin Fees	-	-	-		-	-	-	-
H&W Audit Fees	11,845	980	880	23,274	594	534	1,575	1,414
Flex Spending - Admin Fees (HCRA, DCRA, TRA)	20,353	1,685	1,513	39,991	1,021	917	2,706	2,430
Bus Pass Subsidy	45,000	3,724	3,345	220,000	5,617	5,044	9,341	8,389
Tuition Reimbursement Program	183,366	15,176	13,629	360,282	9,198	8,260	24,374	21,889
STD and LTD admin fees	192,437	15,927	14,303	266,146	6,795	6,102	22,722	20,405
Wellness Clinics / Programs	746,427	61,778	55,478	1,466,595	37,442	33,624	99,221	89,103
WTW H&W admin fees payable from VEBA trust	65,706	5,438	4,884	129,101	3,296	2,960	8,734	7,844
WTW H&W admin fees not payable from VEBA trust	155,454	12,866	11,554	305,439	7,798	7,003	20,664	18,557
Total Misc Benefit Programs & Costs	**1,489,020**	**123,240**	**110,672**	**4,701,079**	**120,020**	**107,780**	**243,259**	**218,452**
Active Health Care								
VEBA Paid Claims MEDICAL	38,258,572	3,166,491	2,843,582	49,998,239	1,276,466	1,146,296	4,442,957	3,989,878
VEBA Paid Claims PHARMACY	9,908,817	820,109	736,476	14,981,940	382,492	343,487	1,202,601	1,079,963
VEBA Paid Claims DENTAL	2,048,689	169,561	152,270	3,752,043	95,790	86,022	265,351	238,292
VEBA Paid Claims VISION		-	-		-	-	-	-
HSA Funding	8,191	678	609	71,400	1,823	1,637	2,501	2,246
Employee Withholdings	(3,864,672)	(319,862)	(287,243)	(8,057,668)	(205,714)	(184,736)	(525,576)	(471,979)
Pharmacy Rebates	(2,518,254)	(208,425)	(187,170)	(4,768,893)	(121,751)	(109,335)	(330,176)	(296,505)
Administration Fees	1,124,920	93,105	83,610	2,276,343	58,116	52,189	151,220	135,799
Opt-out Funding, Affordable Care Act		-	-		-	-	-	-
Total Active Health Care	**44,966,263**	**3,721,657**	**3,342,134**	**58,253,405**	**1,487,222**	**1,335,559**	**5,208,879**	**4,677,693**
Life, LTD & Business Travel Ins								
Life Insurance	2,539,255	210,163	188,731	3,772,384	96,310	86,488	306,473	275,219
Life insurance withholdings	(2,018,433)	(167,057)	(150,021)	(3,200,905)	(81,720)	(73,386)	(248,776)	(223,407)
Business Travel Insurance	23,781	1,968	1,768	36,685	937	841	2,905	2,609
LTD insurance premiums	2,143,337	177,394	159,304	2,997,147	76,518	68,715	253,912	228,019
Total Life, LTD & Business Travel Ins	**2,687,940**	**222,469**	**199,782**	**3,605,311**	**92,044**	**82,658**	**314,513**	**282,440**
Total	**49,143,223**	**4,067,366**	**3,652,588**	**66,559,795**	**1,699,286**	**1,525,998**	**5,766,651**	**5,178,585**
Affiliate Charges							38	34
Grand Total	**49,143,223**	**4,067,366**	**3,652,588**	**66,559,795**	**1,699,286**	**1,525,998**	**5,766,689**	**5,178,619**

Trend Assumptions

Medical

Medical and Pharmacy Trend

Medical underwriting trend encompasses several components. It is not solely the price inflation for a given medical service unit. The components found in trend include the following:

- **Unit price inflation**: Annual price inflation for a fixed "market basket" of services
- **Technology and intensity**: The additional cost of newer, more expensive technology and services (advanced imaging, advancements in prescription drugs, etc.).
- **Utilization**: Greater use of medical services over time. Driven by an aging population and the availability of greater medical technology.
- **Cost-shifting**: Typically occurs as a result of costs being held down (fixed fee schedules for government programs such as Medicare and Medicaid) which are passed on to private payers, notably employer-sponsored medical plans.
- **Plan design leveraging (high deductible plans)**: When plans with high member cost sharing (such as deductibles >$1,000) don't periodically increase their fixed cost elements (deductibles, out-of-pocket maximums), they tend to experience a "leveraged" (higher) trend due to medical trend pushing more people above deductibles and out-of-pocket maximums each year.
- **Impact of large claims**: The incidence of large claims in a population is another factor affecting observed trend.

The factors above in large part explain why observed medical trends have exceeded historical CPI increases by a significant margin. Currently, medical trends are lower than the rate of CPI, which is a change from prior years when medical trends were higher than CPI.

Survey data shows that U.S. medical cost is expected to rise between 6.5% and 6.8% for 2023

1. Pricewaterhouse Coopers medical cost trend: Behind the numbers 2022 (2023 report not yet available)
   - Expected medical and Rx cost increase 6.5% (2022)

https://www.pwc.com/us/en/industries/health-industries/library/assets/pwc-hri-behind-the-numbers-2022.pdf

2. Aon Carrier Trend Report
   - Expected medical cost increase 9.2% (global) / 6.5% (U.S.)

https://www.aon.com/getmedia/01fefa12-0ca6-4d5a-8754-cf8691bcc19b/global-medical-trend-rates-report.pdf

3. Willis Towers Watson Global Medical Trends Survey Report
   - Expected medical cost increase 6.8%

https://www.wtwco.com/en-US/insights/2022/10/2023-global-medical-trends-survey-report

Summary

The total cost trend is based on expected cost increases for medical, specialty pharmacy and non-specialty pharmacy as they have different expected cost increases:

- Based on WTW analysis, medical cost trend is estimated to be 6% and pharmacy trend in total to be 10%
  - 10% pharmacy trend is made up of a Specialty pharmacy trend of 13% and a Non-specialty pharmacy trend of 3%
  - PWC's trend recommendation was 18%, however, this included impact of pending legislation and is not an actuarial trend; after discussion with Xcel Energy, it was decided to use a pharmacy trend of 14%
    - 10% trend was used to trend pharmacy claims to 2022; 14% trend was used from 2022 to 2024
- Each pricing group has a different split of the total cost between medical and pharmacy cost, but total (composite) trend is estimated to fall between 5.5% and 6.0%