Direct Testimony and Schedules
Ross L. Baumgarten

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-21-678
Exhibit___(RLB-1)

Cost Assignment and Allocation Principles

November 1, 2021

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Schedules

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Ross L. Baumgarten. I am employed by Xcel Energy Services Inc. (XES or Service Company), the service company subsidiary of Xcel Energy, as Manager of Service Company Accounting.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. As Manager of Service Company Accounting, I am responsible for the general administration of XES, including accounting, billing, allocations, policies and procedures, service agreements, internal audits, external audits, and external reporting to state and federal regulatory agencies. A description of my qualifications, duties, and responsibilities is set forth in Exhibit___(RLB-1), Schedule 1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. In my testimony, I:

- Present the Cost Assignment and Allocation Manual (CAAM) demonstrating how our cost assignment and allocation methodologies and processes ensure that our costs to serve customers are assigned to the appropriate entities;
- Outline the process for allocating XES charges;
- Identify unique features of the General Allocator and certain other allocations for the Northern States Power Company–Minnesota (NSPM) jurisdiction, and the adjustment necessary to implement the required allocation factor (Total Allocated Labor Hours With Overtime (FTE Hours) rather than Number of Employees) for interim rates and request

that the Company be permitted to dispense with this adjustment;

- Explain the Company's process for allocating costs between its gas and electric utilities;
- Discuss affiliate transactions between the Xcel Energy operating companies; and
- Explain the process for allocating costs to our non-regulated business activities.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

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

- Section II explains our cost assignment and allocation principles and processes, and shows they conform to the principles and guidance adopted by the Commission.
- Section III presents the conclusions of my testimony.

II. COST ASSIGNMENT AND ALLOCATION

Q. PLEASE SUMMARIZE THIS SECTION OF YOUR TESTIMONY.

A. In this section, I discuss the framework of our cost allocation and assignment principles, including the Service Agreement between XES and NSPM, and the NSPM CAAM. I then discuss the services provided by XES to NSPM, and how the cost of those services is either directly assigned (direct charge) or allocated (indirect charge) to the Company. I explain the allocation methods used, and quantify the adjustment in this case that results from the use of FTE Hours in Minnesota instead of the Number of Employees in our General Allocator and certain other allocations. Finally, I discuss how we handle transactions between Xcel Energy operating company affiliates and NSPM's non-regulated business activities.

A. Cost Assignment and Allocation Framework

Q. PLEASE SUMMARIZE THE COMPANY'S OVERALL PHILOSOPHY FOR RECORDING COSTS.

A. Our overall philosophy is to record costs for all products and services in a consistent, equitable manner to ensure they are recovered from the customers of the entity responsible for the costs incurred. This philosophy is designed to reasonably apportion fully distributed costs to individual operating companies, like NSPM, and to avoid cross-subsidization between the operating companies and any non-regulated business activities.

Q. ARE THERE GUIDING PRINCIPLES RELATED TO THIS PHILOSOPHY THAT ARE APPLIED BY XCEL ENERGY?

A. Yes. To implement this philosophy, our cost assignment and allocation process follows the guiding principles set forth in the Commission's decision in Docket No. E,G999/CI-90-1008. These principles are applied to both the regulated utility services and non-regulated business activities across Xcel Energy. NSPM's hierarchical cost allocation principles are as follows:

1) Tariffed rates shall be used to value tariffed services provided.
2) Costs shall be directly assigned to either regulated or non-regulated business activities whenever possible.
3) Costs that cannot be directly assigned are common costs, which shall be grouped into homogeneous cost categories. Each cost category shall be allocated based upon indirect cost causation.

4) When neither direct nor indirect measures of cost causation can be found, the cost category shall be allocated based upon a general allocator.

Using this process ensures that all subsidiaries are charged for their appropriate share of costs. Thus, our efforts to appropriately allocate and assign costs are aligned with our customers' expectations and interests that they pay for only those costs that are part of the services they receive from the Company.

Q. PLEASE SUMMARIZE THE COMPANY'S APPROACH TO COST ASSIGNMENT AND ALLOCATION USING THESE PRINCIPLES.

A. In accordance with the Commission's Order in Docket No. E,G002/CI-90-1008, the Company strives to direct charge or assign wherever possible. Direct charges occur when a service being rendered is for the benefit of a specific legal entity only. Allocated, or indirect, charges occur when services cannot be directly assigned to a specific legal entity.

Q. WHAT IS THE BASIS OF THE ALLOCATED CHARGES?

A. We use allocation percentages or ratios to assign non-Company-specific costs. These allocation percentages or ratios are calculated using allocation methods and formulas based on allocation statistics reflecting Company operations, such as the number of customers, dollar amount of revenues, dollar amount of plant assets, megawatt-hours (MWh) of generation, and number of customer bills. I discuss allocations further in Section II. C. below.

Q. HOW DOES THE COMPANY PUT THESE PRINCIPLES INTO PRACTICE?

A. We have a Service Agreement that describes the services provided by XES to NSPM (and the other operating companies and affiliates), as well as a CAAM that identifies the methodologies used to ensure expenditures are appropriately and consistently assigned or allocated:

- among utility operations within NSPM (natural gas and electric);
- among jurisdictions within NSPM (Minnesota, North Dakota, and South Dakota); and
- to the non-regulated business activities operated within NSPM.

The CAAM also helps promote a greater understanding of the Company's cost assignment and allocation principles by providing detailed reference information for both XES and NSPM personnel.

Q. ARE THESE DOCUMENTS SUBJECT TO COMMISSION APPROVAL?

A. Yes. In its November 20, 2014 Order in Docket No. E,G002/AI-14-234, the Commission approved the Second Amendment to the Service Agreement with certain modifications, and directed the Company to submit an annual filing for review and approval of any proposed changes to its allocation methods. We have subsequently submitted annual filings which have been approved or acknowledged (where approval was not required) by the Commission – most recently by Commission Order dated March 17, 2021 in Docket No. E,G002/AI-20-514. That Order approved the Fifth Amendment to the NSPM Service Agreement, which the Company filed with the Commission on May 29, 2020 (Docket No. E,G002/AI-20-514). Key updates included: 1) changes to recognize the realignment of Risk services as a part of the Internal Audit area due to changes in our executive structure; 2) addition of a definition for Total Assets Ratio including Xcel Energy Inc.'s Per Book Assets; and 3) addition of a new allocation method for advanced metering infrastructure costs. A copy of the Fifth Amendment to the NSPM Service Agreement is provided as Exhibit___(RLB-1), Schedule 2.

The Company's first CAAM was approved by the Commission as part of our natural gas rate case in Docket No. G002/GR-04-1511. NSPM's CAAM, updated effective September 30, 2021, is provided as Exhibit___(RLB-1), Schedule 3. Although the CAAM has been updated over the years since its first approval, the cost assignment and allocation principles applied by NSPM are not new and have been applied in the development of the test year cost of service in all of NSPM's rate cases since Docket No. G002/GR-04-1511.

Q. DOES THE CAAM REFLECT COST ALLOCATION PRINCIPLES THAT HAVE BEEN ADOPTED BY THE COMMISSION?

A. Yes. The principles reflected in the CAAM are based on the guiding principles set forth in the Commission's Order in Docket No. E,G999/CI-90-1008. In our May 26, 2021 Petition seeking approval of the current Service Agreement (Docket No. E,G002/AI-21-356), the Company re-affirmed its commitment to the cost allocation principles established in Docket No. E,G999/CI-90-1008, and described how its cost allocation procedures implement and adhere to those principles.

Q. WHAT WAS THE PURPOSE AND FUNCTION OF THE MOST RECENT UPDATES TO THE CAAM?

A. The CAAM is updated annually, as well as on an ad-hoc basis, to ensure that the included documentation and methodologies listed within the CAAM remain current. There have been a number of updates to the CAAM since the Company's 2010 test year rate case filing (Docket No. G002/GR-09-1153).

The changes between the version of the CAAM included with that rate case application and the current CAAM primarily relate to updates of active legal entities in the Xcel Energy holding company structure, the addition of new regulated and non-regulated business activities, the addition of customer accounting non-regulated overhead for the use of customer accounting service of NSPM, and minor text updates for additional clarity and consistency purposes.

Q. HOW IS THE CAAM USED IN THIS PROCEEDING?

A. The 2022 test year budgeted costs used by Company witness Mr. Benjamin C. Halama to develop the 2022 test year revenue requirement were developed using the principles contained in the current CAAM.

Q. HAS THE COMPANY PROVIDED A LIST OF, AND DESCRIPTIONS FOR, THE VARIOUS ALLOCATION METHODS USED FOR THE TEST YEAR?

A. Yes. A list of the allocation factors used by XES in its general ledger system for each of our operating companies is provided in Exhibit___(RLB-1), Schedule 4. This schedule also includes a description of each method, by Allocating Cost Center (ACC), as well as the 2022 test year percentage allocated to NSPM. Exhibit___(RLB-1), Schedule 5 presents a detailed description of the statistics used to calculate the allocation percentages for these methods, as well as the calculation of the NSPM allocation percentages by ACC. The detailed descriptions of the calculation of the allocation ratios can be found in Appendix A of the Service Agreement, included as Schedule 2.

Q. ARE THESE THE SAME ALLOCATION METHODS THAT ARE APPLIED IN OTHER JURISDICTIONS SERVED BY XCEL ENERGY UTILITY OPERATING COMPANIES?

A. Yes, with one exception. A change to the General Allocator and certain other allocators used for the Minnesota jurisdiction of NSPM was required by the Commission's March 15, 2011 Order in Docket No. E,G002/AI-10-690. I discuss the impact of using the General Allocator and other allocators specific to Minnesota in Section II.C.1. below. Other than these exemptions required by Minnesota Commission Order, the allocation methods applied in this case are the same allocation methods that are in effect and approved in NSPM's other operating jurisdictions (North Dakota and South Dakota), and in the operating jurisdictions of the other Xcel Energy operating companies: Northern States Power Company–Wisconsin (NSPW), Public Service Company of Colorado (PSCo), and Southwestern Public Service Company (SPS).

Q. HAVE THERE BEEN ANY CHANGES TO THE COMPANY'S ACCOUNTING AND ALLOCATION SYSTEMS SINCE THE COMPANY'S 2010 TEST YEAR RATE CASE (DOCKET NO. G002/GR-09-1153)?

A. Yes. The Company implemented its new SAP General Ledger in January of 2016, and the Work and Asset Management system in phases in 2016 and 2017. Because it has been several years since these systems were implemented, prior to making this rate case filing, the Company has made a number of other filings with the Commission using SAP, such as rider recovery requests, our July 28, 2017 petition for approval of two contracts with Company affiliate Nicollet Projects I LLC regarding purchasing a portfolio of community solar garden projects,[1] and our October 3, 2019 request for approval of affiliated interest agreements between the Company and Mankato Energy Center LLC and

[1] *See In the Matter of Xcel Energy's Petition for Approval of Affiliated Interest Agreements*, Docket No. E002/AI-17-577, ORDER APPROVING AFFILIATED INTEREST AGREEMENTS (June 12, 2018).

Mankato Energy Center II LLC, which became non-regulated affiliates and wholly owned subsidiaries of Xcel Energy Inc.[2]

There were no changes in either the legal entities or functional organizations as part of the implementation of the SAP General Ledger, nor any changes to the calculation of allocation statistics. However, as with any new system, the terminology and process steps may differ somewhat from one system to another. Company witness Ms. Melissa L. Ostrom provides additional updates on the SAP General Ledger in her Direct Testimony.

Q. IS THE COST ASSIGNMENT AND ALLOCATION FRAMEWORK SUBJECT TO OVERSIGHT BY ANY OTHER REGULATORY AGENCIES?

A. Yes. The cost assignment and allocation framework utilized by XES is under the oversight of the Federal Energy Regulatory Commission (FERC) through periodic audits.

Q. HAS XES GONE THROUGH AN AUDIT BY THE FERC IN WHICH THE COST ASSIGNMENT AND ALLOCATION FRAMEWORK WAS REVIEWED?

A. Yes. XES underwent a FERC audit that covered the period of January 1, 2014 through December 31, 2018. The final audit report was issued on August 29, 2019, in FERC Docket No. FA17-4-000.

Q. WHAT WERE THE FINDINGS AS A RESULT OF THE FERC AUDIT THAT HAVE AN IMPACT ON THE TEST YEAR?

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[2] *See In the Matter of the Petition of Northern States Power Company for Approval of Affiliated Interest Purchase Power Agreement with Mankato Energy Center I and II*, Docket No. E002/AI-19-622, ORDER APPROVING AFFILIATED INTEREST AGREEMENTS AND OTHER ACTION (February 7, 2020).

A. The FERC audit of XES included two findings that impact costs assigned to NSPM, including the 2022 test year. The first finding addressed the allocation of capital software to the Company's non-utility affiliates. The second finding related to the cost allocation of XES income tax expense. There were no other findings identified in the FERC audit report that impact the test year.

Q. PLEASE EXPLAIN THE FIRST FINDING IN MORE DETAIL.

A. Historically, capital costs related to software applications have been recorded to the operating companies, the primary users of the applications. As other affiliate companies receive indirect benefits of certain corporate software applications, the FERC finding required a retrospective adjustment as well as a prospective change in how software capital costs are recorded, ensuring that all operating companies and affiliates that receive direct or indirect benefits from the software also receive a portion of the capital charges.

Q. WHAT CHANGES WERE MADE TO ADDRESS THIS AUDIT FINDING?

A. Effective upon the conclusion of the FERC audit, a retrospective adjustment was made to the impacted software application capital balances to assign costs to all operating companies and affiliates that receive direct or indirect benefits from the software. The allocation of software capital costs was updated on a prospective basis to include all operating companies and affiliates that receive direct or indirect benefits from the software.

Q. PLEASE EXPLAIN THE SECOND FINDING FROM THE FERC AUDIT.

A. Historically, XES income tax expense was allocated to operating companies which comprise the majority of XES activities that generate income tax expense. FERC found that XES should have allocated income tax expense to all Xcel

Energy companies that benefited from XES's activities that caused XES to incur income tax expense.

Q. WHAT DID THE COMPANY DO TO ADDRESS THIS TAX EXPENSE-RELATED AUDIT FINDING?

A. Effective January 1, 2020, XES income tax expense is being allocated to all operating companies and affiliates benefiting from XES's activities that cause XES to incur income tax expense.

Q. HAS FERC ISSUED ANY VERIFICATION THAT THE COMPANY HAS ADEQUATELY ADDRESSED ITS AUDIT FINDINGS?

A. The Company made a filing with FERC on April 29, 2020 (Docket No. FA-17-4-001) which provided a refund report for the FERC formula rates after the FERC audit. According to a January 28, 2021 notification, the Company addressed all findings to FERC's satisfaction subsequent to the audit. The notification further stated that all corrective actions had been completed, and that the implementation phase of the audit is closed.

Q. ARE THERE ANY FURTHER ITEMS RELATED TO THE FERC AUDIT THAT HAVE IMPACTED THE 2022 TEST YEAR?

A. No.

B. Xcel Energy Services Company Charges

Q. PLEASE DESCRIBE THE SERVICES PROVIDED BY XES.

A. Consistent with the CAAM and the Service Agreement, XES cost assignment and allocation processes apportion costs including:

- Operations and maintenance (O&M) costs of providing corporate services to XES affiliates, such as NSPM. These services typically include any managerial, financial, legal, engineering, marketing, auditing, statistical, advertising, publicity, tax, research or any other service, information or data, which is sold or furnished for a charge;
- O&M costs for preliminary planning related to capital software projects that benefit more than one operating company or other affiliate;
- Shared facilities O&M costs that are recorded in cost pools referred to in SAP as Allocating Cost Centers (ACCs). These costs may include (depending on the shared facility), administrative property services labor and non-labor costs, utility expenses, maintenance costs for structures and systems, a prorated share of property taxes (for owned buildings), and rent and occupancy expenses (for leased buildings); and
- Fleet, Warehousing, and Purchasing O&M costs that are recorded to ACCs.

Q. PLEASE PROVIDE AN OVERVIEW OF THE METHODS XES USES TO ASSIGN AND ALLOCATE COSTS TO THE COMPANY.

A. XES direct *assigns* costs when the specific operating company or affiliate (or the specific department or business area within the operating company or affiliate) that should be billed can be identified. For example, the XES Controller's organization can charge NSPM for the work that has been performed to prepare a regulatory filing in Minnesota. Another example is an XES engineer direct charging labor costs related to a gas distribution project directly to the Gas Distribution business area under the Minnesota Gas Jurisdiction. Direct charge internal orders are used to track and directly charge a specific affiliate as well as a specific jurisdiction and/or business area within that affiliate.

XES *allocates* costs when a service provided by XES employees cannot be directly assigned to one affiliate. A description of the XES allocation methodology for each service is provided in the Allocation Ratios section of Appendix A of the Service Agreement. To allocate costs that cannot be directly assigned, XES first identifies homogeneous cost pools known as ACCs that have the same cost driver and then selects the allocation method that has the most cost-causative relationship to the cost driver to allocate the charges within the ACC. Indirect charge internal orders are used to track and allocate costs that cannot be directly assigned to the appropriate ACC. For example, the Risk Management department negotiates the corporate umbrella insurance policies that benefit every operating affiliate. Therefore, the costs incurred by Risk Management to negotiate the policies would be considered indirect charges and are allocated proportionally to every operating affiliate.

Q. WHAT DOES XES DO TO ENSURE THAT XES COSTS ARE RECORDED, ASSIGNED, AND ALLOCATED CORRECTLY?

A. XES takes the following steps to ensure its costs are correctly recorded, assigned, and allocated:

- Makes the policies and procedures regarding the recording of costs available on the Xcel Energy internal web site for access by all Xcel Energy personnel;
- Provides mandatory training, delivered through a combination of classroom, online/computer-based and individual/one-on-one trainings;
- Conducts regular reviews of any allocations by Finance and Accounting department personnel; and
- Conducts internal audits of XES policies and procedures and their application.

The Company also monitors the accuracy of XES charges through formal and informal review processes, including business area reviews with the operating company Presidents.

Q. DOES XES REPORT ITS CHARGES TO THE XCEL ENERGY OPERATING COMPANIES AND AFFILIATES?

A. Yes. XES files a FERC Form 60 report on an annual basis. This report shows XES billings to the Xcel Energy operating companies and affiliates, including a list of approved allocation methods. A copy of the 2020 XES FERC Form 60 is provided as Exhibit___(RLB-1), Schedule 6.

C. Allocation Methods and Factors

Q. IN GENERAL, WHAT ARE THE METHODS USED TO ALLOCATE COSTS TO AND WITHIN THE COMPANY?

A. There are two primary allocation methods: the General Allocator and other Service Company cost allocators and the Utility Allocator. I will discuss each of these allocation methods in this section of my testimony.

Q. WHAT IS THE BASIS OF THESE ALLOCATION METHODS?

A. Each allocation method relies on underlying entity statistics relevant to the types of charges that need to be allocated to an Xcel Energy operating company, affiliate, or business area within an operating company. In this way, the Company seeks to align its cost allocation methods with a reasonable representation of cost causation.

Q. HOW OFTEN ARE THE OPERATING COMPANY AND AFFILIATE STATISTICS USED IN THE ALLOCATION FACTORS UPDATED?

A. The allocation ratios and allocation factors are recalculated annually effective for April business based on the prior calendar-year statistics.[3] XES will also update the statistics used in the allocation ratios and allocation factors when there is a significant change, such as the addition or deletion of an operating company or affiliate, if material.

Q. ARE THE ALLOCATION METHODS CONSISTENT ACROSS ALL XCEL ENERGY OPERATING COMPANIES?

A. No. As I mentioned previously, in Docket No. E,G002/AI-10-690, the Commission required that NSPM use a unique allocation method for its General Allocator and certain other allocators. Specifically, instead of using Number of Employees, as we do in all other jurisdictions, we use FTE Hours to allocate certain costs to the Minnesota jurisdiction. A list of the allocation factors for XES based on FTE Hours is provided in Exhibit___(RLB-1), Schedule 4(a). As I describe in more detail below, the Company is proposing to discontinue this adjustment, which is unique to NSPM, for purposes of setting final rates in this proceeding and future filings.

Q. HAVE THERE BEEN ANY CHANGES IN THE COMPANY'S USE OF ALLOCATIONS SINCE THE COMPANY'S 2010 TEST YEAR RATE CASE (DOCKET NO. G002/GR-09-1153)?

A. Yes. The Company previously utilized an "Allocating Workorders" method, by which the Company used specific workorders to assign certain types of Business Systems-related costs to various functional areas in the operating companies under the prior JDE General Ledger. With the switch to the SAP General

[3] XES annually updates four allocation statistics and allocation percentages related to the Joint Operating Agreement and trading activities starting with January business. The statistics are based on the prior calendar year.

Ledger, and as individual projects were completed, Allocating Workorders were phased out and are no longer utilized with all Business Systems costs now being direct-charged or utilizing approved cost allocation methodologies.

Q. WHAT DEGREE OF PRECISION DOES THE COMPANY ACHIEVE FOR ITS ALLOCATORS?

A. The Company has incorporated the use of four decimal places in the development of the relevant allocators since the Commission's Order in Docket No. E,G002/AI-10-690. We have likewise calculated the allocators in this case using four decimal places. We continue to believe that this provides a reasonable degree of precision.

1. General Allocator

Q. PLEASE DESCRIBE THE GENERAL ALLOCATOR.

A. As mentioned above, allocators are used when a service provided by XES employees cannot be directly assigned to an affiliate. The General Allocator is used to allocate common costs when neither direct nor indirect measures of cost causation can be used to assign costs to operating companies and/or affiliates. The calculation used in all jurisdictions other than Minnesota is comprised of three equally weighted factors: Total Assets, Total Revenues, and Number of Employees. However, in Minnesota this allocator currently uses FTE Hours instead of Number of Employees.

Q. PLEASE DISCUSS THE FTE HOURS COMPONENT IN MORE DETAIL.

A. The FTE Hours component of Minnesota's three-factor formula that makes up the General Allocator is calculated as a percentage of a portion of the total direct and allocated labor hours[4] for NSPM relative to the total direct and allocated labor hours for all affiliates receiving allocations through the General Allocator. FTE Hours is averaged together with Total Assets and Total Revenues, the other two allocation factors that make-up the General Allocator. In contrast, all other jurisdictions in which Xcel Energy operates use Number of Employees, rather than FTE Hours, as part of the three-factor formula that makes up the General Allocator.

Q. IS THE GENERAL ALLOCATOR THE ONLY ALLOCATION METHOD IN WHICH NUMBER OF EMPLOYEES WAS REPLACED WITH FTE HOURS TO ALLOCATE COSTS TO THE MINNESOTA GAS JURISDICTION?

A. No. FTE Hours is also included in other allocation methods besides the General Allocator, as noted in Exhibit___(RLB-1), Schedule 5(a). The greatest impact, however, is to the General Allocator.

Q. WHY IS FTE HOURS USED IN PLACE OF NUMBER OF EMPLOYEES IN MINNESOTA?

A. In a March 2011 Order in Docket No. E,G002/AI-10-690,[5] the Commission required the Company to use FTE Hours in place of Number of Employees. The Commission made this decision for two primary reasons:

> First, the labor component of the general allocator is designed in a way that results in no labor-related costs being allocated to unregulated subsidiaries that do not have their own payrolls. This is unreasonable on its face since no business can have labor costs of zero. Similarly,

[4] This includes productive regular, overtime, and premium hours.

[5] *In the Matter of Northern States Power Company's Cost Allocation Procedures and General Allocator,* Docket No. E,G002/AI-10-690, ORDER REQUIRING CHANGE IN GENERAL ALLOCATOR AND REQUIRING FILINGS (March 15, 2011); ERRATUM NOTICE (March 25, 2011).

> allocating the full costs of each employee to the subsidiary on whose payroll he or she appears overstates the labor costs of that subsidiary and understates the labor costs of any other subsidiary for whose benefit the employee occasionally performs services.[6]

Since the Commission's March 2011 Order, in each rate case, the Company has adjusted its allocation methods to reflect FTE Hours rather than Number of Employees.

Q. WHY DOES THE COMPANY FEEL THAT NUMBER OF EMPLOYEES IS A REASONABLE AND APPROPRIATE METHOD TO ALLOCATE COMPANY COSTS?

A. This method is based on the number of employees for each company, with common officers assigned to Xcel Energy Inc., and reasonably apportions fully distributed costs. Number of Employees provides for a baseline need of support provided to each company by the Service Company when combined with the other two factors that make up the General Allocator. Using Number of Employees provides for a consistent and stable metric driven by staffing levels to support current company needs as well as near-term needs. FTE Hours, in contrast, represents labor hours charged for a historical period that represents specific activities undertaken by employees within that period, which can result in a variable statistic driven by project-based work that can vary from period to period.

Using Number of Employees provides for a more stable statistic that represents current and future staffing needs, as Xcel Energy does not have a practice of hiring employees to fill short-term needs and then laying off the employees once

[6] Id. at 1-2, quoting *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E002/GR-08-1065, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 21 (Oct. 23, 2009).

the project is complete. Instead, the Company strategically deploys employees to support projects on an as-needed basis to maximize value for our customers and for the Company.

Q. ARE LABOR-RELATED COSTS ASSIGNED TO UNREGULATED SUBSIDIARIES WHEN THE COSTS ARE ALLOCATED BASED ON THE NUMBER OF EMPLOYEES?

A. Yes. The General Allocator uses Number of Employees with the common officers assigned to Xcel Energy Inc. as one of three components of the allocation ratio in all other jurisdictions. Assigning common officers to Xcel Energy Inc. along with the Total Revenues and Total Assets components of the General Allocator ensures that nonregulated companies receive a reasonable apportionment of allocated costs. As of December 31, 2020, there were 13 common officers assigned to Xcel Energy Inc., and therefore the Employee Ratio included 13 common officers, or 0.1666 percent of total headcount. By comparison, FTE Hours as calculated for the same period produced 7,837 FTE Hours charged to nonregulated companies, which represents 0.0364 percent of total FTE Hours. Therefore, using Number of Employees with the common officers assigned to Xcel Energy Inc. provides for a larger allocation of costs to Xcel Energy's nonregulated companies than using FTE Hours.

Q. DOES ALLOCATING THE FULL COSTS OF EACH EMPLOYEE TO THE SUBSIDIARY ON WHOSE PAYROLL HE OR SHE APPEARS OVERSTATE THE LABOR COSTS OF THAT SUBSIDIARY AND UNDERSTATE THE LABOR COSTS OF ANY OTHER SUBSIDIARY FOR WHOSE BENEFIT THE EMPLOYEE OCCASIONALLY PERFORMS SERVICES?

A. No, I believe the manual calculation we perform to calculate FTE Hours results in the opposite effect. In performing the calculation for the FTE Hours adjustment, hours charged to allocators that utilize Number of Employees are excluded so as not to skew the FTE Hours results. Excluding labor hours that are allocated by ratios utilizing Number of Employees results in the elimination of 18.3 percent of total Service Company labor hours, which includes a significant portion of hours charged by administrative functions including Human Resources, Accounting and Finance, Legal, and Business Systems. As a result of excluding these hours, the FTE Hours calculation does not provide for an accurate reflection of the level of support provided to each company by the Service Company.

Each employee is responsible for charging their labor, and associated labor overheads, based on the work that they are performing. When a Service Company employee performs work for a nonregulated company, the nonregulated company is direct-charged, assigning labor and labor-related overheads to that company. Similarly, if an operating company employee performs work for another operating company, the employee direct-charges their time to the company they are performing work for, charging labor and labor-related overheads to that company and providing a credit to the company for which that employee resides.

Q. ARE THERE OTHER REASONS THE COMPANY WISHES TO MOVE AWAY FROM MAKING AN ADJUSTMENT FOR THE MINNESOTA JURISDICTION?

A. Yes. Our systems allow us to use a single allocation calculation for each allocation method. Because Minnesota is the exception, our systems are set up to allocate costs using Number of Employees rather than FTE Hours.

Therefore, it is necessary that we manually make an adjustment to the costs allocated to the Minnesota Electric and Gas Jurisdiction annually for reporting purposes and also with each rate case filing in the Minnesota jurisdiction.

Q. WHAT IS THE COMPANY PROPOSING IN THIS PROCEEDING?

A. For final rates in this proceeding, the Company is proposing to discontinue using FTE Hours as a unique component in the General Allocator as well as other allocation ratios using Number of Employees just for the Minnesota Electric and Gas Jurisdiction. As I discuss in more detail below, the requirement to use a different allocator (FTE Hours) in Minnesota makes our allocations inconsistent across jurisdictions and does not provide greater accuracy than allocations based on Number of Employees. All other jurisdictions we serve use allocations based on Number of Employees for purposes of setting rates. While both methods utilize prior year statistics in setting current year allocations, an allocation based on the Number of Employees is less subject to fluctuations.

Q. DO YOU EXPECT CHANGES IN FTE HOURS IN THE FUTURE?

A. Yes. If the FTE Hours adjustment were to continue to be utilized, we would continue to expect changes in FTE Hours each year based on operational needs and specific events in a given year. Overtime hours can change significantly from year to year based on the timing of major overhauls and/or outages at the generating plants, as well as overtime related to major storm events. While the Number of Employees is also subject to change, it is less volatile and it would be more consistent to utilize the same calculations across all jurisdictions.

Q. DID THE COMPANY NONETHELESS CALCULATE THE FTE HOURS ADJUSTMENT FOR PURPOSES OF THIS CASE?

A. Yes. Consistent with the Commission's prior orders, including Order Point 3 in the Commission's June 12, 2018 Order in Docket No. E002/AI-17-577,[7] for interim rates the Company utilized the FTE Hours adjustment in light of the existing Commission Order. This adjustment is discussed in the Company's Interim Rate Petition and supporting schedules. Additionally, the Company is providing the allocation percentages resulting in that adjustment in my Direct Testimony and Exhibit___(RLB-1), Schedules 5(a) and 5(b).

Schedule 5(a) shows the number of direct and allocated labor hours used to calculate the allocation ratios for the 2022 test year.

Schedule 5(b) shows the calculation of the adjustments to the 2022 test year (for NSPM Total Company), applying the difference between the Number of Employees factor and the FTE Hours factor included in Minnesota's General Allocator, as well as the other affected ACC allocators.

2. *Utility Allocations*

Q. WHAT IS THE PURPOSE OF COMMON UTILITY ALLOCATIONS?

A. Utility O&M allocations are developed to allocate NSPM common (electric and natural gas) utility Administrative and General (A&G) costs charged to FERC accounts 920 through 935 to the electric and natural gas utilities. They are also used to allocate NSPM common (electric and natural gas) utility customer accounting, customer information, and sales costs charged to FERC accounts 901 through 917 to the electric and natural gas utilities.

[7] *"The ASA between XES and Nicollet Projects will be subject to future review in rate recovery proceedings where Xcel will demonstrate that all cost allocations are consistent with past Commission orders."* at 7.

Q. WHAT METHOD IS USED TO ALLOCATE THE NSPM (TOTAL COMPANY) COMMON CUSTOMER-RELATED UTILITY COSTS BETWEEN THE ELECTRIC AND NATURAL GAS UTILITIES?

A. The method used to allocate common customer-related utility costs between electric and natural gas utilities is the number of customer bills. The method used to allocate the commodity portion of the bad debt between electric and natural gas utilities is associated revenues.

Q. IS THE METHOD USED TO ALLOCATE THE NSPM (TOTAL COMPANY) COMMON A&G-RELATED UTILITY COSTS BETWEEN THE ELECTRIC AND NATURAL GAS UTILITIES THE SAME AS WAS USED IN NSPM'S LAST ELECTRIC AND GAS RATE CASES?

A. Yes. In the 2022 budget, A&G-related FERC accounts 925 and 926 were allocated to the Minnesota electric and natural gas utilities based on labor. However, all other common A&G costs were allocated to the electric and natural gas utilities based on a weighted three-factor formula comprised of revenue, utility plant-in-service, and supervised O&M. (Supervised O&M refers to O&M costs which are included in FERC account 500 through FERC account 917). The three-factor formula measures three distinct aspects of the Company's operations and results in an appropriate assignment of costs to the electric and natural gas utilities. This is consistent with NSPM's hierarchical cost allocation principles described earlier in my testimony. Step 4 of these principles specifically addresses the use of the General Allocator when no cost causative link exists.

Q. ARE THE 2022 TEST YEAR O&M AND RATE BASE UTILITY ALLOCATION METHODOLOGIES AND ALLOCATION FACTORS PROVIDED IN YOUR TESTIMONY?

A. Yes. The 2022 test year O&M Utility Allocation methodology is explained in Section VI of the CAAM, provided as Schedule 3, and the 2022 test year Utility Allocation factors are further detailed in Exhibit___(RLB-1), Schedule 7. The 2022 test year utility rate base allocation methodology is explained in Section VI of the CAAM, and the 2022 test year utility rate base allocation factors are detailed in Mr. Halama's Direct Testimony.

D. Affiliate Transactions

Q. PLEASE EXPLAIN THE BENEFITS THAT SHARED O&M SERVICES BETWEEN NSPM (TOTAL COMPANY) AND THE AFFILIATED UTILITY OPERATING COMPANIES PROVIDE TO MINNESOTA GAS CUSTOMERS.

A. The provision of services by NSPM (Total Company) to other legal entities reduces overhead costs related to those services, which further reduces the amount of cost recovered from our customers. In addition, NSPM (Total Company) receives services from other operating companies at cost, which eliminates the need for NSPM (Total Company) itself to develop those services and incur the related overhead costs.

Q. WHAT TYPES OF O&M CHARGES BETWEEN NSPM (TOTAL COMPANY) AND OTHER AFFILIATED UTILITY OPERATING COMPANIES ARE INCLUDED IN THE 2022 TEST YEAR BUDGET?

A. The allocated O&M charges between NSPM (Total Company) and other Xcel Energy regulated operating companies in the 2022 test year are limited to small amounts of facilities costs and related labor overhead costs, which are discussed in Section V of the CAAM. Exhibit___(RLB-1), Schedule 8 provides a description and the dollar amounts of the charges between NSPM (Total Company) and NSPW (Total Company), PSCo, and SPS. For the 2022 test year, estimated charges from NSPM (Total Company) to NSPW (Total Company) total $0.09 million, and charges from NSPW (Total Company) to NSPM (Total Company) total $0.02 million. All test year charges between NSPM (Total Company) and either SPS and PSCo total less than $0.01 million, as illustrated in Schedule 8.

Q. ARE THERE ANY OTHER AFFILIATED INTEREST TRANSACTIONS THAT ARE RELEVANT TO THIS CASE?

A. Yes. I would like to provide additional information related to cost allocations for the Company's recent amended agreement with Liberty Paper, Inc. (Docket No. E002/M-19-663).

Q. HOW DOES THE LIBERTY PAPER, INC. AMENDED AGREEMENT RELATE TO COST ALLOCATIONS IN THIS PROCEEDING?

A. When the Commission approved the amended agreement with Liberty Paper, Inc., in its February 21, 2020 Order in Docket No. E002/M-19-663, the Commission included a requirement that, for the duration of steam sales to Liberty Paper, Inc., the Company must demonstrate the reasonableness of the Company's proposed cost allocations related to the steam sales. The allocation of costs to Liberty Paper, Inc., and the reasonableness of those costs, are discussed in Section III of NSPM's CAAM, provided as Schedule 3.

E. Non-Regulated Business Activity Allocations

Q. PLEASE IDENTIFY NSPM'S NON-REGULATED BUSINESS ACTIVITIES.

A. The Company's non-regulated business activities include the following, which are further described in Section III of NSPM's CAAM:

- HomeSmart (in-home appliance protection services);
- Infowise (provides energy management reporting solutions to non-residential customers);
- Customer Owned Street Lighting Maintenance (maintenance services to communities for street light systems);
- Sherco Steam Sales to Liberty Paper Inc. (steam supplied to meet thermal needs).

Q. WHAT IS THE AMOUNT OF THE NSPM (TOTAL COMPANY) NON-REGULATED BUSINESS ACTIVITIES?

A. The NSPM (Total Company) non-regulated business activities account for approximately 0.73 percent of NSPM (Total Company) total 2020 actual revenues and 0.25 percent of NSPM (Total Company) 2020 actual operating expenses (excluding purchased fuel, power and gas expenses). Exhibit___(RLB-1), Schedule 9 provides the supporting calculations. The 2020 Securities and Exchange Commission (SEC) Form 10-K for NSPM, provided as Exhibit___(RLB-1), Schedule 10, is the source of the statistics used in these calculations, and the applicable pages are referenced in the footnotes of Schedule 9.

Q. ARE ALLOCATIONS MADE TO THE NSPM (TOTAL COMPANY) NON-REGULATED BUSINESS ACTIVITY?

A. Yes. Non-regulated business activity allocations ensure that: 1) the costs for services provided to the NSPM (Total Company) non-regulated business activities are billed representing a fully-distributed cost; and 2) gas and electric utility operations are not subsidizing non-regulated business activities. In addition, NSPM (Total Company) allocates a portion of its corporate costs using the labor-related overhead and the corporate residual allocation presented in Exhibit___(RLB-1), Schedule 11. All allocations made to or by NSPM (Total Company) as a result of these activities related to affiliated interest agreements are reasonable and have not resulted in any customer subsidization of non-regulated activities of affiliated companies.

Q. HAVE THE TEST YEAR NON-REGULATED BUSINESS ACTIVITY ALLOCATION METHODOLOGY AND ALLOCATION FACTORS BEEN PROVIDED IN YOUR TESTIMONY?

A. Yes. The test year allocation methodology is explained in Section VII of the CAAM, and the test year non-regulated business activity allocation factors are listed in Schedule 11.

Q. ARE THERE ANY ADDITIONAL COMMISSION ORDERS REGARDING ALLOCATIONS THAT YOU HAVE NOT ADDRESSED IN YOUR DIRECT TESTIMONY?

A. Yes. In the Commission's August 3, 2015, Order in Docket No. E002/AI-14-759, the Commission required that the Company provide certain information related to Xcel Energy Transmission Development Company, LLC, or Xcel Energy Southwest Transmission Company, LLC. The Company acknowledges the reporting requirements under that Commission Order, but it has nothing to report at this time, as the transmission companies have not undertaken any relevant projects. Consequently, we ask to be released from any further reporting requirements related to these affiliated interests unless or until any such work is undertaken by Xcel Energy Transmission Development Company, LLC, or Xcel Energy Southwest Transmission Company, LLC.

III. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY

A. Our cost allocation processes are designed to ensure that the costs to provide service to our customers are recorded to the appropriate legal entities. They emphasize the importance of accuracy, facilitate business area accountability, and result in a reasonable, accurate forecast of the costs we expect to incur. In light of these guiding principles, Xcel Energy requests that the Commission approve the cost allocation methodologies used by the Company in setting final rates, including the use of Number of Employees instead of FTE Hours for the calculation of the Company's General Allocator. As discussed above in my Direct Testimony, the General Allocator is only used when a Service Company employees doing work for a nonregulated company is unable to direct-charge that labor because the work supports both regulated and nonregulated operations. Using Number of Employees in calculating the General Allocator provides for a more stable statistic that reflects the Company's strategic deployment of employees to support projects and allows for a more accurate reflection of the level of support provided by the Service Company.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Statement of Qualifications

Ross L. Baumgarten

Manager of Service Company Accounting
Xcel Energy Services Inc.

I received a Bachelor of Arts in Business Administration, with a major in accounting, from the University of St. Thomas in 2008.

My current position with Xcel Energy Services Inc. (XES) is Manager, Service Company Accounting. I am responsible for the general administration of XES, including accounting, billing, allocations, policies and procedures, service agreements, internal audits, external audits and external reporting to state and federal regulatory agencies.

I have been employed by XES since December 2013, holding positions in Service Company Accounting, Transmission Accounting, and External Reporting.

Prior to joining XES, I was employed by Grant Thornton LLP as a senior financial and operational auditor where I performed financial statement audits and benefit plan audits for companies in various industries including manufacturing, hospitality, and technology.

FIFTH AMENDMENT TO SERVICE AGREEMENT
BETWEEN
NORTHERN STATES POWER COMPANY,
a Minnesota corporation
AND
XCEL ENERGY SERVICES INC.

THIS FIFTH AMENDMENT TO SERVICE AGREEMENT ("Fifth Amendment") is made and entered into as of the 19th day of May 2020, by and between Northern States Power Company, a Minnesota corporation ("Client Company") and Xcel Energy Services Inc. ("Service Company").

WHEREAS, Client Company and Service Company entered into that certain Service Agreement dated as of August 15, 2004 ("Original Service Agreement");

WHEREAS, the Original Service Agreement has been amended from time to time;

WHEREAS, the Original Service Agreement was most recently amended by a Fourth Amendment to Service Agreement dated as of December 14, 2015 and filed in Compliance with the Minnesota Public Utilities Commission's November 19, 2015 Order in Docket No. E,G002/AI-15-536 ("Fourth Amendment" and the Original Service Agreement as amended, the "Amended Service Agreement");

WHEREAS the Amended Service Agreement is subject to the jurisdiction of state utility commissions and the Federal Energy Regulatory Commission;

WHEREAS, additional amendments to the Amended Service Agreement are necessary to recognize new allocation methodologies that are being implemented by the Client Company and Service Company;

WHEREAS, additional amendments to the Amended Service Agreement are necessary to recognize realignment of activities within certain Service Functions of the Service Company;

WHEREAS, Client Company and Service Company mutually desire, by means of this Fifth Amendment, to further amend the Amended Service Agreement as set forth below;

NOW THEREFORE, for and in consideration of the mutual covenants contained in this Fifth Amendment and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties agree as follows:

1. Appendix A to the Amended Service Agreement is deleted in its entirety and replaced with the contents of Schedule 1 to this Fifth Amendment.

2. Except as expressly amended by this Fifth Amendment, all other provisions of the Amended Service Agreement remain in full force and effect.

3. This Fifth Amendment to Service Agreement shall be subject to all necessary and prudent regulatory approvals.

[SIGNATURE PAGE FOLLOWS]

IN WITNESS WHEREOF, the parties hereto have executed this Fifth Amendment to Service Agreement to be executed as of the date and year first above written.

XCEL ENERGY SERVICES INC.

BY: Wendy B. Mahling
Name: Wendy B. Mahling
Title: Vice President, Secretary

NORTHERN STATES POWER COMPANY,
A MINNESOTA CORPORATION

BY: ChrBClar
Name: Christopher B. Clark
Title: President

[SIGNATURE PAGE TO FIFTH AMENDMENT TO SERVICE AGREEMENT]

Appendix A

DESCRIPTION OF SERVICES TO BE PROVIDED BY XCEL ENERGY SERVICES INC. AND DETERMINATION OF CHARGES FOR SUCH SERVICES TO THE OPERATING COMPANIES AND OTHER AFFILIATES

Description of Services Provided

A description of the services provided by Xcel Energy Services is detailed below. Identifiable costs will be directly assigned to the Operating Companies and other affiliates. For costs that are for services of a general nature and cannot be directly assigned, the method of allocation is described below for each service provided.

a) *Executive Management Services**

Description - Represents charges for Xcel Energy Inc. ("Xcel Energy") executive management and services, including, but not limited to, officers of Xcel Energy.

Method of Allocation - Executive Management Services indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio.

b) *Investor Relations**

Description - Provides communications to investors and the financial community. Coordinates the transfer agent and shareholder record keeping functions and plans the annual shareholder meeting.

Method of Allocation - Investor Relations indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio.

c) *Internal Audit & Risk**

Description - Reviews internal controls and procedures to ensure assets are safeguarded and transactions are properly authorized and recorded. Evaluates contract risks and trading risks.

Method of Allocation - Internal Audit and Risk indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio, except for:

(1) indirect costs associated with proprietary trading activities, which will be allocated based on the Joint Operating Agreement Peak Hour Megawatt Load Ratio, provided, however, that indirect costs provided jointly for both generation

trading activities and proprietary trading activities will be allocated based on the Joint Operating Agreement Labor Hours Ratio.

*d) Legal**

Description - Provides legal services related to labor and employment law, litigation, contracts, rates and regulation, environmental matters, real estate and other legal matters.

Method of Allocation - Legal indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio.

*e) Claims Services**

Description - Provides claims services related to casualty, public and company claims.

Method of Allocation - Claims Services indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio.

*f) Corporate Communications**

Description - Provides corporate communications, speech writing and coordinates media services. Provides advertising and branding development for the companies within the Xcel Energy system. Manages and tracks all charitable contributions made on behalf of the Xcel Energy system.

Method of Allocation - Corporate Communications indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio.

*g) Employee Communications**

Description - Develops and distributes communications to employees.

Method of Allocation - Employee Communications indirect costs will be allocated based on the Employee Ratio.

*h) Corporate Strategy & Business Development**

Description - Facilitates development of corporate strategy and prepares strategic plans, monitors corporate performance and evaluates business opportunities. Develops and facilitates process improvements.

Method of Allocation - Corporate Strategy & Business Development indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio.

*i) Government Affairs**

Description - Monitors, reviews and researches government legislation.

Method of Allocation - Government Affairs indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio.

*j) Facilities & Real Estate**

Description - Operates and maintains office buildings and service centers. Procures real estate and administers real estate leases. Administers contracts to provide security, housekeeping and maintenance services for such facilities. Procures office furniture and equipment.

Method of Allocation - Facilities & Real Estate indirect costs will be allocated based on the Employee Ratio.

*k) Facilities Administrative Services**

Description - Includes but is not limited to the functions of mail delivery, duplicating and records management.

Method of Allocation - Facilities Administrative Services indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio.

*l) Supply Chain**

Description - Includes contract negotiations, development and management of supplier relationships and acquisition of goods and services. Also includes inventory planning and forecasting, ordering, accounting and database management. Warehousing services includes receiving, storing, issuing, shipping, returns, and distribution of material and parts.

Method of Allocation - Supply Chain will be direct charged. Any management and oversight of the payment and reporting services activities that cannot be direct charged will be allocated based on the Invoice Transaction Ratio.

*m) Supply Chain Special Programs**

Description - Develops and implements special programs utilized across the company such as procurement cards, travel services, and compliance with corporate MWBE (minority women business expenditures) program goals.

Method of Allocation - Supply Chain Special Programs indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio.

*n) Human Resources**

Description - Establishes and administers policies related to employment, compensation and benefits. Maintains Human Resources computer system, the tuition reimbursement plan, and diversity program. Coordinates the bargaining strategy and labor agreements with union employees. Provides technical and professional development training and general Human Resources support services.

Method of Allocation - Human Resources indirect costs will be allocated based on the Employee Ratio.

*o) Finance & Treasury**

Description - Coordinates activities related to securities issuance, including maintaining relationships with financial institutions, cash management, investing activities and monitoring the capital markets. Performs financial and economic analysis.

Method of Allocation - Finance & Treasury indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio, except for:

(1) indirect costs associated with proprietary trading activities, which will be allocated based on the Joint Operating Agreement Peak Hour Megawatt Load Ratio, provided, however, that indirect costs provided jointly for both generation trading activities and proprietary trading activities will be allocated based on the Joint Operating Agreement Labor Hours Ratio.

*p) Accounting, Financial Reporting & Taxes**

Description - Maintains the books and records. Prepares financial and statistical reports, tax filings and ensures compliance with the applicable laws and regulations. Maintains the accounting systems. Coordinates the budgeting process.

Method of Allocation – Accounting, Financial Reporting & Taxes indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio, except for:

(1) indirect costs associated with proprietary trading activities, which will be

allocated based on the Joint Operating Agreement Peak Hour Megawatt Load Ratio, provided, however, that indirect costs provided jointly for both generation trading activities and proprietary trading activities will be allocated based on the Joint Operating Agreement Labor Hours Ratio.

*q) Payment & Reporting**

Description - Processes payments to vendors and prepares statistical reports.

Method of Allocation - Payment & Reporting indirect costs will be allocated based on the Invoice Transaction Ratio.

*r) Receipts Processing**

Description - Processes payments received from customers of the Operating Companies and affiliates.

Method of Allocation - Receipts Processing indirect costs will be allocated based on the Customer Bills Ratio.

*s) Payroll**

Description - Processes payroll including but not limited to time reporting, calculation of salaries and wages, payroll tax reporting and compliance reports.

Method of Allocation - Payroll indirect costs will be allocated based on the Employee Ratio.

*t) Rates & Regulation**

Description - Determines the Operating Companies' regulatory strategy, revenue requirements and rates for electric and gas customers. Coordinates the regulatory compliance requirements and maintains relationships with the regulatory bodies.

Method of Allocation - Rates & Regulation indirect costs will be allocated based on the Direct Labor Ratio.

*u) Energy Supply Engineering and Environmental**

Description - Provides engineering services to the generation business. Establishes policies and procedures for compliance with environmental laws and regulations. Researches emerging environmental issues and monitors compliance with environmental requirements. Oversees environmental cleanup projects.

Method of Allocation - Energy Supply Engineering and Environmental services will be direct charged; administrative support functions that cannot be direct charged will be allocated based on the Total Plant Ratio.

*v) Energy Supply Business Resources**

Description - Provides performance, specialists and analytical services to the Operating Companies' generation facilities.

Method of Allocation - Energy Supply Business Resources indirect costs will be allocated based on the MWh Generation Ratio.

*w) Energy Markets Regulated Trading & Marketing**

Description - Provides electric trading services to the Operating Companies' electric generation systems including load management, system optimization and resource acquisition.

Method of Allocation - Energy Markets Regulated Trading & Marketing indirect costs will be allocated based on the Total MWh Sales Ratio, except for:

(1) indirect costs associated with proprietary trading activities, which will be allocated based on the Joint Operating Agreement Peak Hour Megawatt Load Ratio, provided, however, that indirect costs provided jointly for both generation trading activities and proprietary trading activities will be allocated based on the Joint Operating Agreement Labor Hours Ratio.

*x) Energy Markets - Fuel Procurement**

Description - Purchases fuel for Operating Companies electric generation systems (excluding nuclear).

Method of Allocation - Energy Markets Fuel Procurement indirect costs will be allocated based on the MWh Generation Ratio.

*y) Energy Delivery Marketing**

Description - Develops new business opportunities and markets the products and services for the Delivery Business Unit.

Method of Allocation - Energy Delivery Marketing will be direct charged.

*z) Energy Delivery Construction, Operations & Maintenance (COM)**

Description - Constructs, maintains and operates electric and gas delivery systems.

Method of Allocation - Energy Delivery COM indirect costs will be allocated based on the Delivery Services Gross Plant Ratio.

*aa) Energy Delivery Engineering/Design**

Description - Provides engineering and design services in support of capacity planning, construction, operations and material standards.

Method of Allocation - Energy Delivery Engineering/Design services will be direct charged; administrative support functions that cannot be direct charged will be allocated based on the Delivery Services Gross Plant Ratio.

*bb) Marketing & Sales**

Description - Provides marketing and sales services for the Operating Companies and affiliates for their electric and natural gas customers including strategic planning, segment identification, business analysis, sales planning and customer service.

Method of Allocation - Marketing & Sales indirect costs will be allocated based on the Revenue Ratio.

*cc) Customer Service**

Description - Provides service activities to retail and wholesale customers. These services include meter reading, customer billing, call center and credit and collections.

Method of Allocation - Customer Service indirect costs will be allocated based on the Customers Ratio. Indirect costs associated with administering low income and certified medical customer assistance programs will be allocated based on a composite of the average of the Special Needs Customer Contacts Ratio and Residential Customers Ratio.

*dd) Business Systems**

Description - Provides basic information technology services such as: application management, voice and data network operations and management, customer support services, problem management services, security administration and systems management. In addition, Business Systems acts as a single point of contact for delivery of all technical services to Xcel Energy. They partner with vendors to ensure the delivery of benchmarking, continuous improvement, and leadership around strategic initiatives and key developments in the marketplace.

Method of Allocation - Business Systems indirect costs will be allocated using any of the allocation ratios or combination of ratios.

*ee) Aviation Services**

Description - Provides aviation and travel services to employees.

Method of Allocation - Aviation Services will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio, and the Total Assets Ratio.

*ff) Fleet**

Description - Oversees the Operating Companies' Fleet Services Group.

Method of Allocation - Fleet will be direct charged.

*Corporate Governance activities within this Service Function will be allocated using the average of the Total Assets Ratio including Xcel Energy Inc.'s Per Book Assets, Revenue Ratio with intercompany dividends assigned to Xcel Energy Inc., and Employee Ratio.

Allocation Ratios

The following ratios will be utilized as outlined above.

Revenue Ratio - Based on the sum of the monthly revenue amounts for the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Revenue Ratio with intercompany dividends assigned to Xcel Energy Inc. - Based on the sum of the monthly revenue amounts for the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. Xcel Energy Inc. will be assigned the amount of intercompany dividends. This ratio will be determined annually, or at such time as may be required due to significant changes.

Employee Ratio - Based on the number of employees at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes. For regulatory purposes, in the Minnesota jurisdiction, the Total Allocated Labor Hours Including Overtime shall be used. Total Allocated Labor Hours Including Overtime (FTE Hours) is the methodology ordered by the Minnesota Public Utilities Commission in Docket No. E,G002/AI-10-690, which is based on the number of labor hours including overtime for employees at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies.

Employee Ratio with number of common officers assigned to Xcel Energy Inc. - Based on the number of employees at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. Xcel Energy Inc. will be assigned the number of common officers. This ratio will be determined annually, or at such time as may be required due to significant changes.

Total Assets Ratio - Based on the total assets as of December 31 for the prior year, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Total Assets Ratio including Xcel Energy Inc's Per Book Assets - Based on the total assets as of December 31 for the prior year, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. Xcel Energy Inc. will be assigned the per book assets of Xcel Energy Inc. This ratio will be determined annually, or at such time as may be required due to significant changes.

Square Footage Ratio - Based on the total square footage as of December 31 for the prior year. The numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Invoice Transaction Ratio - Based on the sum of the monthly number of invoice transactions processed for the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually or at such time as may be required due to significant changes.

Customer Bills Ratio - Based on the average of the monthly total number of customer bills issued during the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

MWh Generation Ratio - Based on the sum of the monthly electric MWh generated by type of generator during the prior year ending December 31, the numerator of which is for an applicable Operating Company and the denominator of which is for all applicable Operating Companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Total MWh Sales Ratio - Based on the sum of the monthly electric MWh hours sold during the prior year ending December 31, the numerator of which is for an applicable Operating Company and the denominator of which is for all applicable Operating Companies. This includes sales to ultimate customers, wholesale customers, and non-requirement sales for resale. This ratio will be determined annually, or at such time as may be required due to significant changes.

Customers Ratio - Based on the average of the monthly total electric customers (and/or gas customers, or residential, business and large commercial and industrial customers, where applicable) for the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Delivery Services Gross Plant Ratio - Based on transmission and distribution gross, both electric and, for the prior year ending December 31, the numerator of which is an applicable Operating Company and the denominator of which is for all applicable Operating Companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Provided, however, as follows:
(1) If the costs being allocated are directly related only to electric transmission, the ratio shall be based on the electric transmission gross plant;
(2) If the costs being allocated are directly related only to electric distribution, the ratio shall be based on the electric distribution gross plant;
(3) If the costs being allocated are directly related only to gas transmission, the ratio shall be based on the gas transmission gross plant;
(4) If the costs being allocated are directly related only to gas distribution, the ratio shall be based on the gas distribution gross plant;
(5) If the costs being allocated are directly related only to electric transmission and electric distribution, the ratio shall be based on the sum of the electric transmission gross plant and the electric distribution gross plant;
(6) If the costs being allocated are directly related only to electric transmission and gas transmission, the ratio shall be based on the sum of the electric transmission gross plant and the gas transmission gross plant;
(7) If the costs being allocated are directly related only to electric transmission and gas distribution, the ratio shall be based on the sum of the electric transmission gross plant and the gas distribution gross plant;
(8) If the costs being allocated are directly related only to electric distribution and gas transmission, the ratio shall be based on the sum of the electric distribution gross plant and the gas transmission gross plant;
(9) If the costs being allocated are directly related only to electric distribution and gas distribution, the ratio shall be based on the sum of the electric distribution gross plant and the gas distribution gross plant;
(10) If the costs being allocated are directly related only to gas transmission and gas distribution, the ratio shall be based on the sum of the gas transmission gross plant and the gas distribution gross plant;
(11) If the costs being allocated are directly related only to electric transmission, electric distribution, and gas transmission, the ratio shall be based on the sum of the electric transmission gross plant, the electric distribution gross plant, and the gas transmission gross plant;
(12) If the costs being allocated are directly related only to electric transmission, electric distribution, and gas distribution, the ratio shall be based on the sum of the electric transmission gross plant, the electric distribution gross plant, and the gas distribution gross plant;
(13) If the costs being allocated are directly related only to electric transmission, gas transmission, and gas distribution, the ratio shall be based on the sum of the electric transmission gross plant, the gas transmission gross plant, and the gas distribution gross plant;
(14) If the costs being allocated are directly related only to electric distribution, gas

transmission, and gas distribution, the ratio shall be based on the sum of the electric distribution plant, the gas transmission gross plant, and the gas distribution gross plant.

Meters Ratio - Based on the number of meters at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

Provided, however, as follows:
(1) If the costs being allocated are directly related only to Advanced Metering Infrastructure ("AMI") enabled meters, the ratio shall be based on the number of AMI enabled meters.

Customer Contacts Ratio - Based on the total annual number of customer contacts at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

If the costs being allocated are directly related only to the support of special needs customers, such as those receiving low income energy assistance and those having certified medical conditions, the Special Needs Customer Contacts Ratio shall be used.

Special Needs Customer Contacts Ratio – Based on the number of contacts received by the special needs customer department at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

Accounts Payable Transactions Ratio - Based on the total annual number of accounts payable transactions by system application at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

Inventory Transactions Ratio - Based on the total annual number of inventory transactions by system application at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

Work Management Transactions Ratio - Based on the total annual number of work management transactions by system application at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

Purchasing Transactions Ratio - Based on the total annual number of purchasing transactions by system application at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

Total Plant Ratio - Based on total property, plant and equipment at the end of the prior year ending December 31, the numerator of which is an applicable Operating Company and the denominator of which is for all applicable Operating Companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

Provided, however, as follows:
(1) If the costs being allocated are directly related only to electric production, the ratio shall be based on the total electric production plant;
(2) If the costs being allocated are directly related only to electric transmission, the ratio shall be based on the total electric transmission plant;
(3) If the costs being allocated are directly related only to electric distribution, the ratio shall be based on the total electric distribution plant;
(4) If the costs being allocated are directly related only to gas transmission, the ratio shall be based on the total gas transmission plant;
(5) If the costs being allocated are directly related only to gas distribution, the ratio shall be based on the total gas distribution plant;
(6) If the costs being allocated are directly related only to intangible plant, the ratio shall be based on the total intangible plant;
(7) If the costs being allocated are directly related only to electric production and electric transmission, the ratio shall be based on the sum of the total electric production plant and the total electric transmission plant;
(8) If the costs being allocated are directly related only to electric production and electric distribution, the ratio shall be based on the sum of the total electric production plant and the total electric distribution plant;
(9) If the costs being allocated are directly related only to electric production and gas transmission, the ratio shall be based on the sum of the total electric production plant and the total gas transmission plant;
(10) If the costs being allocated are directly related only to electric production and gas distribution, the ratio shall be based on the sum of the total electric production plant and the total gas distribution plant;
(11) If the costs being allocated are directly related only to electric production and

intangible plant, the ratio shall be based on the sum of the total electric production plant and the total intangible plant;

(12) If the costs being allocated are directly related only to electric transmission and electric distribution, the ratio shall be based on the sum of the total electric transmission plant and the total electric distribution plant;

(13) If the costs being allocated are directly related only to electric transmission and gas transmission, the ratio shall be based on the sum of the total electric transmission plant and the total gas transmission plant;

(14) If the costs being allocated are directly related only to electric transmission and gas distribution, the ratio shall be based on the sum of the total electric transmission plant and the total gas distribution plant;

(15) If the costs being allocated are directly related only to electric transmission and intangible plant, the ratio shall be based on the sum of the total electric transmission plant and the total intangible plant;

(16) If the costs being allocated are directly related only to electric distribution and gas transmission, the ratio shall be based on the sum of the total electric distribution plant and the total gas transmission plant;

(17) If the costs being allocated are directly related only to electric distribution and gas distribution, the ratio shall be based on the sum of the total electric distribution plant and the total gas distribution plant;

(18) If the costs being allocated are directly related only to electric distribution and intangible plant, the ratio shall be based on the sum of the total electric distribution plant and the total intangible plant;

(19) If the costs being allocated are directly related only to gas transmission and gas distribution, the ratio shall be based on the sum of the total gas transmission plant and the total gas distribution plant;

(20) If the costs being allocated are directly related only to gas transmission and intangible plant, the ratio shall be based on the sum of the total gas transmission plant and the total intangible plant;

(21) If the costs being allocated are directly related only to gas distribution and intangible plant, the ratio shall be based on the sum of the total gas distribution plant and the total intangible plant;

(22) If the costs being allocated are directly related only to electric production, electric transmission, and electric distribution, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, and the total electric distribution plant;

(23) If the costs being allocated are directly related only to electric production, electric transmission, and gas transmission, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, and the total gas transmission plant;

(24) If the costs being allocated are directly related only to electric production, electric transmission, and gas distribution, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, and the total gas distribution plant;

(25) If the costs being allocated are directly related only to electric production, electric transmission, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, and the total

intangible plant;
(26) If the costs being allocated are directly related only to electric production, electric distribution, and gas transmission, the ratio shall be based on the sum of the total electric production plant, the total electric distribution plant, and the total gas transmission plant;
(27) If the costs being allocated are directly related only to electric production, electric distribution, and gas distribution, the ratio shall be based on the sum of the total electric production plant, the total electric distribution plant, and the total gas distribution plant;
(28) If the costs being allocated are directly related only to electric production, electric distribution, and intangible, the ratio shall be based on the sum of the total electric production plant, the total electric distribution plant, and the total intangible plant;
(29) If the costs being allocated are directly related only to electric production, gas transmission, and gas distribution, the ratio shall be based on the sum of the total electric production plant, the total gas transmission plant, and the total gas distribution plant;
(30) If the costs being allocated are directly related only to electric production, gas transmission, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total gas transmission plant, and the total intangible plant;
(31) If the costs being allocated are directly related only to electric production, gas distribution, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total gas distribution plant, and the total intangible plant;
(32) If the costs being allocated are directly related only to electric transmission, electric distribution, and gas transmission, the ratio shall be based on the sum of the total electric transmission plant, the total electric distribution plant, and the total gas transmission plant;
(33) If the costs being allocated are directly related only to electric transmission, electric distribution, and gas distribution, the ratio shall be based on the sum of the total electric transmission plant, the total electric distribution plant, and the total gas distribution plant;
(34) If the costs being allocated are directly related only to electric transmission, electric distribution, and intangible plant, the ratio shall be based on the sum of the total electric transmission plant, the total electric distribution plant, and the total intangible plant;
(35) If the costs being allocated are directly related only to electric transmission, gas transmission, and gas distribution, the ratio shall be based on the sum of the total electric transmission plant, the total gas transmission plant, and the total gas distribution plant;
(36) If the costs being allocated are directly related only to electric transmission, gas transmission, and intangible plant, the ratio shall be based on the sum of the total electric transmission plant, the total gas transmission plant, and the total intangible plant;
(37) If the costs being allocated are directly related only to electric transmission, gas distribution, and intangible plant, the ratio shall be based on the sum of the total

electric transmission plant, the total gas distribution plant, and the total intangible plant;
(38) If the costs being allocated are directly related only to electric distribution, gas transmission, and intangible plant, the ratio shall be based on the sum of the total electric distribution plant, the total gas transmission plant, and the total intangible plant;
(39) If the costs being allocated are directly related only to electric distribution, gas distribution, and intangible plant, the ratio shall be based on the sum of the total electric distribution plant, the total gas distribution plant, and the total intangible plant;
(40) If the costs being allocated are directly related only to electric distribution, gas distribution, and gas transmission, the ratio shall be based on the sum of the total electric distribution plant, the total gas distribution plant, and the total gas transmission plant;
(41) If the costs being allocated are directly related only to gas transmission, gas distribution, and intangible plant, the ratio shall be based on the sum of the total gas transmission plant, the total gas distribution plant, and the total intangible plant;
(42) If the costs being allocated are directly related only to electric production, electric transmission, electric distribution, and gas transmission, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, the total electric distribution plant, and the total gas transmission plant;
(43) If the costs being allocated are directly related only to electric production, electric transmission, electric distribution, and gas distribution, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, the total electric distribution plant, and the total gas distribution plant;
(44) If the costs being allocated are directly related only to electric production, electric transmission, electric distribution, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, the total electric distribution plant, and the total intangible plant;
(45) If the costs being allocated are directly related only to electric production, electric transmission, gas transmission, and gas distribution, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, the total gas transmission plant, and the total gas distribution plant;
(46) If the costs being allocated are directly related only to electric production, electric transmission, gas transmission, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, the total gas transmission plant, and the total intangible plant;
(47) If the costs being allocated are directly related only to electric production, electric distribution, gas transmission, and gas distribution, the ratio shall be based on the sum of the total electric production plant, the total electric distribution plant, the total gas transmission plant, and the total gas distribution plant;
(48) If the costs being allocated are directly related only to electric production, electric distribution, gas transmission, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total electric distribution plant, the total gas transmission plant, and the total intangible plant;
(49) If the costs being allocated are directly related only to electric production, electric distribution, gas distribution, and intangible plant, the ratio shall be based

on the sum of the total electric production plant, the total electric distribution plant, the total gas distribution plant, and the total intangible plant;
(50) If the costs being allocated are directly related only to electric production, gas transmission, gas distribution, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total gas transmission plant, the total gas distribution plant, and the total intangible plant;
(51) If the costs being allocated are directly related only to electric transmission, electric distribution, gas transmission, and gas distribution, the ratio shall be based on the sum of the total electric transmission plant, the total electric distribution plant, the total gas transmission plant, and the total gas distribution plant;
(52) If the costs being allocated are directly related only to electric transmission, electric distribution, gas transmission, and intangible plant, the ratio shall be based on the sum of the total electric transmission plant, the total electric distribution plant, the total gas transmission plant, and the total intangible plant;
(53) If the costs being allocated are directly related only to electric transmission, electric distribution, gas distribution, and intangible plant, the ratio shall be based on the sum of the total electric transmission plant, the total electric distribution plant, the total gas distribution plant, and the total intangible plant;
(54) If the costs being allocated are directly related only to electric transmission, gas transmission, gas distribution, and intangible plant, the ratio shall be based on the sum of the total electric transmission plant, the total gas transmission plant, the total gas distribution plant, and the total intangible plant;
(55) If the costs being allocated are directly related only to electric distribution, gas transmission, gas distribution, and intangible plant, the ratio shall be based on the sum of the total electric distribution plant, the total gas transmission plant, the total gas distribution plant, and the total intangible plant;
(56) If the costs being allocated are directly related only to electric production, electric transmission, gas distribution, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, the total gas distribution plant, and the total intangible plant;
(57) If the costs being allocated are directly related only to electric production, electric transmission, electric distribution, gas distribution, and gas transmission, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, the total electric distribution plant, the total gas distribution plant, and the total gas transmission plant;
(58) If the costs being allocated are directly related only to electric production, electric transmission, electric distribution, gas transmission, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, the total electric distribution plant, the total gas transmission plant, and the total intangible plant;
(59) If the costs being allocated are directly related only to electric production, electric distribution, gas distribution, gas transmission, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total electric distribution plant, the total gas distribution plant, the total gas transmission plant, and the total intangible plant;
(60) If the costs being allocated are directly related only to electric production, electric transmission, gas distribution, gas transmission, and intangible plant, the

ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, the total gas distribution plant, the total gas transmission plant, and the total intangible plant;
(61) If the costs being allocated are directly related only to electric production, electric transmission, electric distribution, gas distribution, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, the total electric distribution plant, the total gas distribution plant, and the total intangible plant;
(62) If the costs being allocated are directly related only to electric transmission, electric distribution, gas distribution, gas transmission, and intangible plant, the ratio shall be based on the sum of the total electric transmission plant, the total electric distribution plant, the total gas distribution plant, the total gas transmission plant, and the total intangible plant.

Total Phones Ratio - Based on the number of phones at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

Total Radios Ratio - Based on the number of radios at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

Total Computers Ratio - Based on the number of computers at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

Total Software Applications Users Ratio - Based on the number of users of a specific software application at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

Joint Operating Agreement Peak Hour Megawatt Load Ratio - Based on that certain Joint Operating Agreement among Northern States Power Company, a Minnesota corporation, Northern States Power Company, a Wisconsin corporation, Public Service Company of Colorado, Southwestern Public Service Company, and Xcel Energy Services Inc., as agent, dated as of October 1, 2004, as may be amended from time to time, that designates costs to be allocated based on peak hour of megawatt load for previous year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Joint Operating Agreement Labor Hours Ratio - Based on that certain Joint Operating Agreement among Northern States Power Company, a Minnesota corporation, Northern States Power Company, a Wisconsin corporation, Public Service Company of Colorado, Southwestern Public Service Company, and Xcel Energy Services Inc., as agent, dated as of October 1, 2004, as may be amended from time to time, that designates costs to be allocated based on labor hours at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company and the denominator of which is for all applicable Operating Companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Direct Labor Ratio – Based on fully-loaded direct-charged Rates and Regulation labor dollars charged to individual operating affiliates by the Rates and Regulation service function. The numerator of which is the fully-loaded direct-charged labor dollars to individual operating affiliates by Rates and Regulation service function and the denominator of which is the total fully-loaded direct-charged labor dollars to all affiliates by the Rates and Regulation service function.

Northern States Power Company

Cost Assignment and Allocation Manual

September 2021

Table of Contents

Section

I. INTRODUCTION

This Cost Assignment and Allocation Manual ("CAAM") was developed to specify the procedures that Northern States Power Company, a Minnesota corporation ("NSPM" or the "Company") follows in assigning and allocating costs among utility departments (electric and gas), among regulated services and non-regulated business activities and among jurisdictions.

NSPM was incorporated in 2000 under the laws of Minnesota and is a wholly owned operating utility subsidiary of Xcel Energy Inc. ("Xcel Energy" or the "Parent"). Xcel Energy was initially established as a registered holding company under the Public Utility Holding Company Act of 1935 ("PUHCA 1935"), with oversight by the Securities and Exchange Commission ("SEC"). On August 8, 2005, the Energy Policy Act of 2005 was signed into law. This repealed PUHCA 1935 and enacted the Public Utility Holding Company Act of 2005 ("PUHCA 2005"), which became effective on February 8, 2006. Responsibility for oversight of public utility holding companies was transferred from the SEC to the Federal Energy Regulatory Commission ("FERC") as a result of the Energy Policy Act of 2005.

NSPM 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. NSPM also purchases, transports, distributes, and sells natural gas to retail customers and transports customer-owned natural gas in Minnesota and North Dakota.

NSPM owns the following direct subsidiaries: United Power and Land Company, which holds real estate; and NSP Nuclear Corporation.

As a member of a holding company system, NSPM receives administrative, management, environmental, and other support services from Xcel Energy Services Inc. ("XES" or the "Service Company"), a centralized service company. The Service Company provides services to Xcel Energy and its subsidiaries, at cost, pursuant to service agreements. The service agreement between NSPM and XES, including all amendments to the original Service Agreement, have been submitted to, and approved by, the Minnesota Public Utilities Commission ("Commission"). The cost allocation methodologies under which XES costs are assigned and allocated are set forth in that Commission approved service agreement, and while those allocation methodologies are not the subject of this NSPM CAAM, they are referenced in several sections herein.

The Service Company is referenced in the CAAM for the following reasons:

- The Service Company is listed as an affiliate company in the Transaction with Affiliates section for the services it provides to NSPM.
- The Service Company and all other companies in the Xcel Energy holding company system of companies are included in the Corporate Organization section to provide a listing of all affiliates of NSPM.
- The Service Company is referenced in the Cost Assignment and Allocation Process section because this section covers processes that may cross multiple legal entities.

The NSPM CAAM contains the following sections:

- Introduction (Section I)
- Corporate Organization (Section II)
- Description of Services (Section III)
- Transactions with Affiliates (Section IV)
- Cost Assignment and Allocation Process (Section V)
- Utility Allocations (Section VI)
- Non-regulated Business Activity Allocations (Sections VII)
- Jurisdictional Allocations (Section VIII)

DEFINITIONS

Abbreviations or Acronyms

The following abbreviations or acronyms are used within the CAAM document:

A&G	Administrative and general
AFUDC	Allowance for funds used during construction
ACC	Allocating cost center
CAAM	Cost Assignment and Allocation Manual
CIP	Conservation improvement program
Commission	Minnesota Public Utilities Commission
FERC	Federal Energy Regulatory Commission
FICA	Federal Insurance Contributions Act
FUTA	Federal Unemployment Tax Act
GAAP	Generally Accepted Accounting Principals
HR	Human Resources
IT	Information Technology
NSPM or the Company	Norther States Power Company, a Minnesota corporation
NSPW	Northern States Power Company, a Wisconsin corporation
NSP System	The electric production and transmission system of NSPM and NSPW operated on an integrated basis and managed by NSPM
O&M	Operating and maintenance
PSCo	Public Service Company of Colorado, a Colorado corporation
PUCHA 1935	Public Utility Holding Company Act of 1935
PUCHA 2005	Public Utility Holding Company Act of 2005
RTU	Remote terminal unit
SAP	SAP general ledger and work and asset management system
SCADA	Supervisory control and data acquisition
SEC	Securities and Exchange Commission
SKF	Statistical key figure
SPS	Southwestern Public Service Company, a New Mexico corporation
SUTA	State Unemployment Tax Authority
Utility subsidiaries or operating companies	NSPM, NSPW, PSCo, and SPS
Xcel Energy or the Parent	Xcel Energy Inc. and its subsidiaries
XES or the Service Company	Xcel Energy Services Inc.

Terms

The following terms are used within the CAAM document:

Accounts Payable – the payment and reporting department of XES.

A&G – includes activity in FERC accounts 920-935, Administrative and General Expenses.

ACC – an organizational unit that collects cost to be allocated using the allocation ratios or factors included in the SKF.

Assessment – the process used by the accounting system to allocate costs from an ACC to the receiving cost element.

Cost Element – an organizational unit to SAP that is used to track costs in the accounting system as they move through the various processing steps.

Customer Accounting Costs – includes activity in FERC accounts 901-903, Customer Accounts Expenses; FERC accounts 906-910, Customer Service and Informational Expenses; and FERC accounts 911-917, Sales Expenses.

Final Cost Center – final cost center defined by business function, company code, and profit center.

Home Cost Center – captures only labor and payroll postings and maps to HR departments.

Internal Order – internal orders are accounting mechanisms used to track expenses associated with certain projects or functions.

Non-Operations and Maintenance Allocations – allocations designed to apportion expenses recorded in accounts other than O&M to electric, gas, thermal and nonutility. The non-O&M costs apportioned include depreciation, payroll taxes, miscellaneous service revenues, amortization expenses, etc.

O&M – includes activity in FERC accounts 500-935 with the exception of the following FERC accounts: 501, Fuel; 901-903, Customer Accounts Expenses; 906-910, Customer Service and Informational Expenses; 911-917, Sales Expenses; and 920-935, Administrative and General Expenses.

Profit Center – SAP data element that identifies the jurisdiction or joint venture owner of revenues and expenses.

Receiving Cost Element – a cost element that receives costs when a settlement or assessment process is run.

Segment – represents electric, gas, thermal, joint venture, or other and is derived by SAP from profit center and cost center.

SKF – the method by which the allocation ratios and factors are organized in the accounting system and linked to ACCs to facilitate the performance of the assessment process to allocate charges.

Supply Chain – the supply chain department of XES.

Work Breakdown Structure – structure used to group all aspects or phases of a given project or organizational group and render them easily reportable.

II. CORPORATE ORGANIZATION

OVERVIEW OF COMPANY SYSTEM

Xcel Energy Inc., a Minnesota corporation, is a registered holding company. Xcel Energy directly owns the utility subsidiaries that serve electric, natural gas, thermal, and propane customers in eight mid-western and western states including portions of Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin. These four utility subsidiaries are Northern States Power Company, a Minnesota corporation ("NSPM"); Northern States Power Company, a Wisconsin corporation ("NSPW"); Public Service Company of Colorado, a Colorado corporation ("PSCo"); and Southwestern Public Service Company, a New Mexico corporation ("SPS"). Along with the utility subsidiaries, the transmission-only subsidiaries, Xcel Energy Southwest Transmission Company, LLC ("XEST"), Xcel Energy Transmission Development Company, LLC ("XETD"), and Xcel Energy West Transmission Company, LLC ("XEWT"); WYCO Development LLC ("WYCO"), a joint venture with CIG to develop and lease natural gas pipelines, storage, and compression facilities; WestGas InterState, Inc. ("WGI"), an interstate natural gas pipeline company comprise the regulated utility operations. Xcel Energy's significant non-regulated subsidiaries are Eloigne Company; Capital Services, LLC; and Nicollet Holdings Company, LLC.

Xcel Energy owns the following additional direct subsidiaries, some of which are intermediate holding companies with additional subsidiaries: Xcel Energy Wholesale Group Inc., Xcel Energy Markets Holdings Inc., Xcel Energy International Inc., Xcel Energy Ventures Inc., Xcel Energy Retail Holdings Inc., Xcel Energy Communications Group Inc., , Xcel Energy WYCO Inc., Xcel Energy Transmission Holding Company, LLC, Xcel Energy Venture Holdings, Inc., Nicollet Holdings Company, LLC, and Xcel Energy Services Inc. Xcel Energy and its subsidiaries collectively are referred to as Xcel Energy Inc., and many do business under the Xcel Energy name. See the following pages for a complete legal entity organizational listing for Xcel Energy Inc. and its subsidiaries.

LIST OF REGULATED & NON-REGULATED AFFILIATES (as of September 30, 2021)

Xcel Energy Inc.
- Northern States Power Company, a Minnesota corporation
  - Crowned Ridge Interconnection Company
  - NSP Nuclear Corporation
  - Private Fuel Storage LLC
  - United Power and Land Company
- Northern States Power Company, a Wisconsin corporation
  - Chippewa and Flambeau Improvement Company
  - Clearwater Investments, Inc.
    - Shoe Factory Holding LLC
  - NSP Lands, Inc.
- Public Service Company of Colorado, a Colorado corporation**
  - 1480 Welton, Inc.
  - Beeman Irrigating Ditch and Milling Company

- Consolidated Extension Canal Company
- East Boulder Ditch Company
- Fisher Ditch Company
- Gardeners Mutual Ditch Company
- Green and Clear Lakes Company
- Hillcrest Ditch and Reservoir Company
- Larimer Land Services, LLC
- Las Animas Consolidated Canal Company
- P.S.R. Investments, Inc.
- United Water Company

Southwestern Public Service Company, a New Mexico corporation
Nicollet Holdings Company, LLC
- Capital Services, LLC
- Nicollet Land Services, LLC

Nicollet Project Holdings, LLC
- Nicollet Projects I, LLC
  - Betcher CSG LLC
  - Foreman's Hill CSG LLC
  - Grimm CSG LLC
  - Heyer CSG LLC
  - Huneke CSG LLC
  - Johnson I CSG LLC
  - Johnson II CSG LLC
  - Krause CSG LLC
  - RJC I CSG LLC
  - RJC II CSG LLC
  - Scandia CSG LLC
  - School Sisters CSG LLC
  - Webster CSG LLC
- Nicollet Projects II, LLC

WestGas InterState, Inc.
Xcel Energy Foundation
Xcel Energy Communications Group Inc.
- Seren Innovations, Inc.*

Xcel Energy Foundation
Xcel Energy International Inc.*
Xcel Energy Markets Holdings Inc.
- e prime, inc.*
- Young Gas Storage Company Ltd.

Xcel Energy Retail Holdings Inc.
- Xcel Energy Performance Contracting Inc.
- Reddy Kilowatt Corporation

Xcel Energy Services Inc.
Xcel Energy Transmission Holding Company, LLC
- Xcel Energy Southwest Transmission Company, LLC
- Xcel Energy Transmission Development Company, LLC
  - Xcel Energy Acorn Transmission, LLC
  - Xcel Energy Birch Transmission, LLC

- Xcel Energy West Transmission Company, LLC
- Xcel Energy Venture Holdings, Inc.
  - Energy Impact Fund Investment LLC
  - Xcel Energy Investments, LLC
- Xcel Energy Ventures Inc.
  - Eloigne Company
    - Bemidji Townhouse LP
    - Chaska Brickstone LP
    - Crown Ridge Apartments LP
    - Cottage Court LP
    - Dakotah Pioneer LP
    - Edenvale Family Housing LP
    - Fairview Ridge LP
    - Farmington Family Housing LP
    - Farmington Townhome LP
    - Hearthstone Village LP
    - J&D 14-93 LP
    - Lauring Green LP
    - Links Lane LP
    - Lyndale Avenue Townhomes LP
    - Mahtomedi Woodland LP
    - Mankato Townhomes LLP
    - Marvin Garden LP
    - Moorhead Townhomes LP
    - Park Rapids Townhomes LP
    - Rochester Townhome LP
    - Rushford Housing LP
    - Safe Haven Homes, LLC
    - Shade Tree Apartments LP
    - Shakopee Boulder Ridge LP
    - Shenandoah Woods LP
    - Sioux Falls Partners LP
    - St. Cloud Housing LP
    - Tower Terrace LP
- Xcel Energy Wholesale Group Inc.*
  - Quixx Corporation*
    - Quixx Carolina, Inc.*
    - Quixxlin Corp.*
- Xcel Energy WYCO Inc.
  - WYCO Development, LLC

* Company is being classified in discontinued operations.
** Minority-ownership ditch and water companies have been excluded.

III. DESCRIPTION OF SERVICES

OVERVIEW

This section provides a description of NSPM's regulated services and non-regulated business activities. Each description identifies the types of costs associated with the service or business activity, and identifies the business area or department which offers the service.

REGULATED SERVICES

ELECTRIC UTILITY

Electric – Residential

Residential electric service represents the provision of electric service to residential customers within the NSPM service territory. Costs associated with this service relate to the generation or purchase and delivery of electricity through Company-owned transmission and distribution facilities, primarily fuel or purchased power costs, facilities O&M and depreciation costs, and A&G costs. These costs reside within the NSPM Electric Utility.

Electric – Commercial and Industrial

Commercial and industrial electric service represents the provision of electric service to commercial and industrial customers within the NSPM service territory. Costs associated with this service relate to the generation or purchase and delivery of electricity through Company-owned transmission and distribution facilities, primarily fuel or purchased power costs, facilities O&M and depreciation costs, and A&G costs. These costs reside within the NSPM Electric Utility.

Electric – Street Lighting

Street lighting electric service represents the provision of electric service to public authorities for lighting streets, highways, parks and other public places, or for traffic or other signal system service through Company-owned or customer-owned lighting equipment. Costs associated with this service relate to the generation or purchase and delivery of electricity through Company-owned transmission and distribution facilities, primarily fuel or purchased power costs, facilities O&M and depreciation costs, and A&G costs. These costs reside within the NSPM Electric Utility.

Electric – Other Sales to Public Authorities

Other sales to public authorities' electric service represent the provision of electric service to public authorities under special agreements or contracts. Costs associated with this service relate to the generation or purchase and delivery of electricity through Company-owned transmission and distribution facilities, primarily fuel or purchased power costs, facilities O&M and depreciation costs, and A&G costs. These costs reside within the NSPM Electric Utility.

Electric - Resale

Resale electric service represents the provision of electric service to NSPM wholesale customers or public authorities for resale to end-user customers or to power marketers. Costs associated with this service relate to the generation or purchase and delivery of electricity through Company-owned transmission and distribution facilities, or through facilities owned by third parties, primarily fuel or purchased power costs, facilities O&M and depreciation costs, and A&G costs. These costs reside within the NSPM Electric Utility.

Electric - Interdepartmental

Interdepartmental electric service represents the provision of electric service to NSPM company facilities at tariff rates. Costs associated with providing this service relate to the generation or purchase and delivery of electricity through Company-owned transmission and distribution facilities, primarily fuel or purchased power costs, facilities O&M and depreciation costs, and A&G costs. These costs reside within the NSPM Electric Utility.

Off-System Electric Sales

NSPM sells electricity not required to serve its native load to off-system customers. Costs related to this activity can include fuel and purchased power costs. The revenues associated with these sales reside in FERC account 447, Sales for Resale-Electric. The costs related to this activity reside in FERC accounts 501, Fuel-Steam Generation; 555, Purchased Power; and 565, Transmission of Electricity by Others. In addition, the Company may allocate production O&M and transmission costs based on a percentage of overall sales relative to the type of off-system sales. These costs reside within the NSPM Electric Utility.

OTHER ELECTRIC OPERATING REVENUE

Rent from Electric Property

Rent from electric property results from the leasing of NSPM owned utility property not currently utilized for the provision of regulated services to non-affiliated third parties. Costs related to this service are primarily A&G costs associated with customer billings, as well as rental contract renewals. The revenue associated with the rentals resides in FERC account 454, Rent from Electric Property.

Interchange Agreement

The electric production and transmission costs of the entire NSP System are shared by NSP-Minnesota and NSP-Wisconsin. A FERC-approved Interchange Agreement between the two companies provides for the sharing of all generation and transmission costs of the NSP System based upon demand and energy ratios reflecting usage by the respective companies. The costs associated with this agreement reside in FERC account 557, Other Power Supply Expenses; and FERC 565, Transmission of Electricity by Others. The revenues reside in FERC account 456.1, Revenue from Transmission of Electricity of Others.

Joint Operating Agreement

The Joint Operating Agreement is a margin sharing agreement associated with proprietary energy trading activities. Revenues are recorded in FERC 456, Other Electric Revenues.

Miscellaneous Electric Revenue

In addition to the services detailed above, there are various activities that cannot be accounted for elsewhere, such as utility locating services, scrap metal sales, WindSource, customer connections, and refuse derived fuel incentive. These revenues are recorded in FERC account 456, Other Electric Revenues.

GAS UTILITY

Gas - Residential

Residential gas service represents the provision of natural gas service to residential customers within the NSPM service territory. Costs associated with this service relate to the purchase and delivery of gas through Company-owned facilities, primarily purchased gas, facilities O&M and depreciation costs, and A&G costs. These costs reside within the NSPM Gas Utility.

Gas – Commercial and Industrial

Commercial and industrial gas service represents the provision of natural gas service to commercial and industrial customers within the NSPM service territory. Costs associated with this service relate to the purchase and delivery of gas through Company-owned facilities, primarily purchased gas, facilities O&M and depreciation costs, and A&G costs. These costs reside within the NSPM Gas Utility. The table below shows the various rate classes within commercial and industrial gas services.

Rate Class	Maximum Requirements – Daily Therms	Maximum Requirements – Annual Therms
Small commercial	Less than 500	Less than 6,000
Large commercial	Less than 500	Greater than 6,000
Small demand billed commercial*	Less than 500	
Large demand billed commercial*	Greater than 500	

* Upstream demand costs are billed based on the highest one-day usage in the customer's history.

Gas – Interruptible

Interruptible gas service represents the provision of natural gas service to interruptible customers within the NSPM service territory. Interruptible service is subject to curtailment when either additional upstream pipeline or local distribution capacity is needed to ensure service to firm customers. Costs associated with this service relate to the purchase and delivery of gas through Company-owned facilities, primarily purchased gas, facilities O&M and depreciation costs, and A&G costs. These costs reside within the NSPM Gas Utility. The table below shows the various rate classes within interruptible gas service.

Rate Class	Maximum Requirements – Daily Therms
Small interruptible	Less than 2,000
Medium interruptible	Greater than 2,000 and less than 50,000
Large interruptible	Greater than 50,000

Gas – Large Firm Transportation

Large firm gas transportation service represents the provision of gas delivery service on behalf of end-use customers, third-party suppliers or marketers whereby NSPM transports gas owned by others over NSPM's gas pipeline system. Costs associated with this service primarily include the facilities O&M and depreciation costs and A&G costs. These costs reside within the NSPM Gas Utility.

Gas – Interruptible Transportation

Interruptible gas transportation service represents the provision of gas delivery service on behalf of end-use customers, third-party suppliers or marketers whereby NSPM transports gas owned by others over NSPM's gas pipeline system. Interruptible transportation gas service is subject to curtailment when either additional upstream pipeline or the local distribution capacity is needed to ensure service to firm customers. Costs associated with this service primarily include the facilities O&M and depreciation costs and A&G costs. These costs reside within the NSPM Gas Utility.

Gas – Negotiated Transportation

Negotiated firm and interruptible gas transportation service (bypass customers) represents the provision of gas delivery service on behalf of end-use customers, third-party suppliers or marketers whereby NSPM transports gas owned by others over NSPM's gas pipeline system. Interruptible transportation gas service is subject to curtailment when either additional upstream pipeline or the local distribution capacity is needed to ensure service to firm customers. Costs associated with this service primarily include the facilities O&M and depreciation costs and A&G costs. These costs reside within the NSPM Gas Utility.

Gas – Interdepartmental

Interdepartmental gas service represents the provision of natural gas service or gas transportation service to NSPM company facilities at tariff rates. Costs associated with providing this service relate to the purchase and delivery of gas through NSPM owned facilities, primarily purchased gas, facilities O&M and depreciation costs, and A&G costs. These costs reside within the NSPM Gas Utility.

Gas – Limited Firm

Standby gas service represents on-system back-up propane service for interruptible service customers. Costs associated with this service primarily include propane purchases and the facilities O&M. These costs reside within the NSPM Gas Utility.

Gas – Daily Balancing Service

Daily balancing gas service represents a service to transportation customers that allows them to remedy deviations between nominated and delivered gas and gas consumed by the transportation customer. Costs associated with this service primarily include upstream pipeline costs. These costs reside within the NSPM Gas Utility.

OTHER GAS REVENUE

Miscellaneous Gas Revenue

Various services are provided that cannot be accounted for elsewhere such as propane transportation charges and bundled sales. These revenues are recorded in FERC account 495, Other Gas Revenues.

COMMON ELECTRIC AND GAS REVENUE

Late Payments Fees/Miscellaneous Service Revenues

Revenues from the additional charges imposed because of customers failure to pay their bill by specified due date are recorded into FERC account 450, Electric Forfeited Discounts; and FERC account 487, Gas Forfeited Discounts. Miscellaneous customer related revenue, such as service connections and returned check charges, are recorded in FERC account 451, Miscellaneous Electric Service Revenue; and FERC account 488, Miscellaneous Gas Service Revenues.

CIP Incentives

The CIP Incentive is a mechanism established by an April 7, 2000 Order of the Commission that provides utilities with an incentive to increase cost-effective utility investment in conservation improvement programs beyond the spending levels required by Minnesota Statute. The revenues associated with the CIP incentives are identified by unique accounts and are recorded in FERC account 456, Other Electric Revenues; and FERC 495, Other Gas Revenues. An adjustment is made to remove these revenues from our cost of service study and they do not impact our revenue requirements.

ConnectSmart

NSPM provides a service for customers moving into or across the region to set up utility service and other subscription services to their homes (e.g., newspaper, local and long-distance telephone, cable TV, etc.). NSPM, through its call center, receives telephone requests for this service, and sends these requests, for a fee, to AllConnect (a third-party contractor) for the coordination of installation of services. Costs related to this activity include direct charges for labor, materials and outside services associated with the service provided. In addition, payroll taxes, lost time, facilities, workers' compensation, incentive, pension, and benefit costs are allocated based on labor dollars, and labor-related overhead and a corporate residual overhead are applied to nonregulated business activities. The revenues and costs associated with this service are identified by unique accounts, and are recorded in FERC 417, Revenues from Nonutility Operations; and FERC 417.1, Expenses from Nonutility Operations. For rate making purposes, in the event this service experiences revenues in excess of direct expenses, an adjustment is made to credit the net impact in FERC 456, Other Electric Operating Revenues, to reflect the benefit of this service to the utility customers.

Hazardous Waste Disposal

NSPM has a Hazardous Waste consolidation facility at Chestnut Service Center in Minneapolis, Minnesota. The facility accepts and consolidates hazardous and specially-regulated waste materials from generating assets, service centers, substations, office buildings, and field operations projects in both NSPM and NSPW service territories. This facility ensures the wastes are properly characterized aggregated and consolidated at approved, permanent and appropriately licensed waste disposal facilities. This facility is also the central collection point for any PCB contaminated electrical equipment.

NON-REGULATED BUSINESS ACTIVITIES

The following business activities have been approved by the Commission as non-regulated business activities. Detailed descriptions of each of the non-regulated business activities are provided in this section.

HomeSmart

Xcel Energy HomeSmart offers resources for the repair, replacement and maintenance of major appliances and systems in customers' homes. This includes service plans to cover certain appliances, sewer and plumbing issues; heating, ventilating and air conditioning (HVAC) systems; replacement assistance coverage; and preventive maintenance. HomeSmart also sells and installs HVAC systems and water heaters. Costs related to these activities include direct charges for labor, equipment, materials, and outside services associated with the services provided. In addition, payroll taxes, lost time, and pension and benefit costs are allocated based on labor dollars. A labor related overhead, a corporate residual overhead, and a Customer Accounting overhead are applied to non-regulated business activities, as applicable. (Please refer to Section VII of the CAAM for more information.) The revenues and costs associated with HomeSmart are identified by unique accounts and are recorded in FERC 417, Revenues from Nonutility Operations; and FERC 417.1, Expenses from Nonutility Operations.

Infowise

Infowise is an energy management reporting solution with customized data for businesses to help manage and control their energy use. This product consists of unique interactive reports with detailed information, including both consumption and demand levels, to help the customer pinpoint and analyze their facility's energy use. By analyzing past energy use, this product can help drive company green strategies while helping customize a strategic business plan for facility managers, as well as deliver a bill estimator tool that keeps track of budgets and identifies cost saving opportunities. Costs related to this activity include direct charges for labor, materials and outside services associated with the service provided. In addition, payroll taxes, lost time, facilities, workers' compensation, incentive and pension and benefits are allocated based on labor dollars, and a labor-related overhead, a corporate residual overhead, and a customer billing overhead are applied to nonregulated business activities, as applicable. (Please refer to Section VII of the CAAM for more information.) The revenues and costs associated with Infowise are identified by unique SAP Cost Centers, and are recorded in FERC accounts 417, Revenues from Nonutility Operations, and 417.1, Expenses from Non-utility Operations. For rate making purposes, in the event this service experiences revenues in excess of direct expenses, an adjustment is made to credit the net impact in FERC 456, Other Electric Operating Revenues, to reflect the benefit of this service to the utility customers.

Customer Owned Street Lighting Maintenance

NSPM supplies maintenance services for communities that own their own street light systems. Maintenance service for customer owned street light systems is limited to the fixture service only; and ranges from full fixture service to partial fixture service where the customer provides the material necessary to repair the streetlight. The customer is responsible for all other repairs and replacements under the "Non-regulated Customer Owned Street Maintenance" service. Costs related to this activity include labor and materials associated with the service provided. In addition, payroll taxes, lost time, and pension and benefit costs are allocated based on labor dollars, and a labor related overhead and a corporate residual overhead are applied to non-regulated business activities. The revenues and costs associated with this service are identified by unique accounts and are recorded in FERC 417, Revenues from Nonutility Operations; and FERC 417.1, Expenses from Nonutility Operations. See Docket E-002/M-92-614 for the Commission order to treat this service as non-regulated.

Sherco Steam Sales to Liberty Paper Inc.

NSPM supplies steam from the Sherburne County Generating Station to Liberty Paper, Inc. ("LPI") in order to meet LPI's thermal energy needs. Costs related to this activity include labor and materials associated with the service provided. In addition, payroll taxes, lost time, and pension and benefit costs are allocated based on labor dollars, and a labor-related overhead is applied to nonregulated business activities. The revenues and costs associated with this service are identified by unique accounts, and are recorded in FERC 417, Revenues from Nonutility Operations; and FERC 417.1, Expenses from Nonutility Operations which are excluded for ratemaking purposes. See Docket Nos. E002/M-93-1253 and E002/M-19-663 for the Commission orders to treat this service as non-regulated. In addition to steam services, LPI takes electric and natural gas services from NSPM which are tariffed services provided at tariffed rates.

IV. TRANSACTIONS WITH AFFILIATES

OVERVIEW

NSPM directly incurs and pays for the majority of its costs, there are, however, services provided to NSPM by other affiliates within the Xcel Energy system of companies. In addition, NSPM provides a limited amount of operations, maintenance, and management advisory services to its affiliates. NSPM has numerous Affiliated Interest Agreements that have been approved by the Commission.

The sections below separately detail the nature and terms of transactions for services and asset transfers provided by NSPM to its affiliates, as well as services and asset transfers provided to NSPM by each of its affiliates. This section includes descriptions of affiliate transactions only and does not include convenience payments.

The cost allocation methodologies under which the Service Company costs are assigned and allocated are set forth in the service agreement, and while they are not the subject of this NSPM CAAM, they are included in this section to provide as complete a picture as possible of all affiliate transactions. The NSPM Service Agreement is reviewed and filed annually with the Commission. The last filing was approved in Docket E,G002/AI-19-371 on July 10, 2019. NSPM's affiliate transactions consist primarily of transactions with the Service Company for administrative, management, accounting, legal, engineering, environmental, and other support services.

Terms of Transactions

Tariff Rate – the price charged to customers under applicable tariffs on file with federal or state regulatory commissions. Tariff rates are used for transactions with affiliates involving the provision of regulated services.

Fully Distributed Cost **–** the term fully distributed cost means that transactions billed include all direct and indirect costs, including overheads. Affiliate transactions billed by NSPM include labor related overheads and a working capital fee when appropriate. This method of assigning and allocating costs to these affiliate transactions ensures that the payments to or by NSPM are reasonable and have not resulted in any ratepayer subsidization. In the table below, fully distributed cost may also refer to a price established in a separate Affiliated Interest Agreement.

NSPM applies a labor related overhead to services provided by NSPM to affiliates and also applies a working capital fee on services NSPM provides to non-NSPM company affiliates. Both the labor related overhead and the working capital fees are discussed in Section VII.

The remainder of this section is detailed by affiliate. Affiliates may be listed under the "Services Provided by NSPM to Affiliates" section and/or the "Services Provided by Affiliates to NSPM" section. The details relating to the nature, frequency, and terms of the affiliate transactions are itemized for NSPM and each affiliate.

SERVICES PROVIDED BY NSPM TO AFFILIATES

Nature of Transactions	Terms
NSPW	
O&M – production, decommissioning, and transmission costs associated with the Interchange Agreement (FERC Docket No. ER15-1575-000).	Fully distributed cost
SCADA and Gas Dispatch – sharing of SCADA costs in accordance with Docket G-002/AI-94-831.	Fully distributed cost
Materials and Supplies – materials and supplies, including any associated freight, purchase loadings, and warehouse loadings.	Fully distributed cost
Miscellaneous – miscellaneous other charges, including labor, associated loadings, and lease costs.	Fully distributed cost
PSCo	
Materials and Supplies – materials and supplies, including any associated freight, purchase loadings, and warehouse loadings.	Fully distributed cost
Joint Operating Agreement – margin sharing associated with proprietary energy trading activities.	Fully distributed cost
Miscellaneous – miscellaneous other charges, including labor, associated loadings, and lease costs.	Fully distributed cost
SPS	
Materials and Supplies – materials and supplies, and any associated freight, purchase loadings, and warehouse loadings.	Fully distributed cost
Joint Operating Agreement – margin sharing associated with proprietary energy trading activities.	Fully distributed cost
Miscellaneous – miscellaneous other charges, including labor and associated loadings and lease costs.	Fully distributed cost

Xcel Energy Inc.

Miscellaneous - miscellaneous other charges, including 401(k) match and a dividend on common stock.	Fully distributed cost

SERVICES PROVIDED BY AFFILIATES TO NSPM

Nature of Transactions	*Terms*
Xcel Energy Services Inc.	
*Executive Management Services** – represents charges for executive management services, including, but not limited to, officers of Xcel Energy.	Fully distributed cost
*Investor Relations** – provides communications to investors and the financial community. Coordinates the transfer agent and shareholder record keeping functions and plans the annual shareholder meeting.	Fully distributed cost
*Internal Audit & Risk** – reviews internal controls and procedures to ensure assets are safeguarded and transactions are properly authorized and recorded. Evaluates contract risks and trading risks.	Fully distributed cost
*Legal** – provides legal services related to labor and employment law, litigation, contracts, rates and regulation, environmental matters, real estate, and other legal matters.	Fully distributed cost
*Claims Services** – provides claims services related to casualty, public, and company claims.	Fully distributed cost
*Corporate Communications** – provides corporate communications, speech writing, and coordinates media services. Provides advertising and branding development for the companies within the Xcel Energy system. Manages and tracks all charitable contributions made on behalf of the Xcel Energy system.	Fully distributed cost
*Employee Communications** – develops and distributes communications to employees.	Fully distributed cost
*Corporate Strategy & Business Development** – facilitates development of corporate strategy and prepares strategic plans, monitors corporate performance, and evaluates	Fully distributed cost

business opportunities. Develops and facilitates process improvements.	
*Government Affairs** – monitors, reviews and researches government legislation.	Fully distributed cost
*Facilities & Real Estate** – operates and maintains office buildings and service centers. Procures real estate and administers real estate leases. Administers contracts to provide security, housekeeping and maintenance services for such facilities. Procures office furniture and equipment.	Fully distributed cost
*Facilities Administrative Services** – includes but is not limited to the functions of mail delivery, duplicating, and records management.	Fully distributed cost
*Supply Chain**– includes contract negotiations, development and management of supplier relationships and acquisition of goods and services. Also includes inventory planning and forecasting, ordering, accounting, and database management. Warehousing services includes receiving, storing, issuing, shipping, returns, and distribution of material and parts.	Fully distributed cost
*Supply Chain Special Programs** – develops and implements special programs utilized across Xcel Energy such as procurement cards, travel services, and compliance with corporate MWBE (minority women business expenditures) program goals.	Fully distributed cost
*Human Resources** – establishes and administers policies related to employment, compensation, and benefits. Maintains HR computer system, the tuition reimbursement plan, and diversity program. Coordinates the bargaining strategy and labor agreements with union employees. Provides technical and professional development training and general HR support services.	Fully distributed cost
*Finance & Treasury** – coordinates activities related to securities issuances, including maintaining relationships with financial institutions, cash management, investing activities, and monitoring the capital markets. Performs financial and economic analysis.	Fully distributed cost
*Accounting, Financial Reporting & Taxes** – maintains financial books and records. Prepares financial and statistical reports, tax filings, and ensures compliance with the applicable laws and regulations. Maintains the	Fully distributed cost

accounting systems. Coordinates the budgeting process.	
*Payment & Reporting** – processes payments to vendors and prepares statistical reports.	Fully distributed cost
*Receipts Processing** – processes payments received from customers of the operating companies and affiliates.	Fully distributed cost
*Payroll** – processes payroll including but not limited to time reporting, calculation of salaries and wages, payroll tax reporting, and compliance reports.	Fully distributed cost
*Rates & Regulation** – determines the operating companies' regulatory strategy, revenue requirements, and rates for retail and wholesale customers. Coordinates the regulatory compliance requirements and maintains relationships with the regulatory bodies.	Fully distributed cost
*Energy Supply Engineering and Environmental** – provides engineering services to the generation business. Establishes policies and procedures for compliance with environmental laws and regulations. Researches emerging environmental issues and monitors compliance with environmental requirements. Oversees environmental cleanup projects.	Fully distributed cost
*Energy Supply Business Resources** – provides performance, specialists, and analytical services to the operating companies generation facilities.	Fully distributed cost
*Energy Markets Regulated Trading & Marketing** – provides electric trading services to the operating companies electric generation systems including load management, system optimization, and resource acquisition.	Fully distributed cost
*Energy Markets-Fuel Procurement** – purchases fuel for operating companies' electric generation systems (excluding nuclear).	Fully distributed cost
*Energy Delivery Marketing** – develops new business opportunities and markets the products and services for the Delivery business unit.	Fully distributed cost
*Energy Delivery Construction, Operations & Maintenance** – constructs, maintains, and operates electric and gas delivery systems.	Fully distributed cost
*Energy Delivery Engineering/Design** – provides engineering	Fully distributed cost

and design services in support of capacity planning, construction, operations, and materials standards.	
*Marketing & Sales** – provides marketing and sales services for the operating companies and affiliates for their electric and natural gas customers including strategic planning, segment identification, business analysis, sales planning, and customer service.	Fully distributed cost
*Customer Service** – provides service activities to retail and wholesale customers. These services include meter reading, customer billing, call center, and credit and collections.	Fully distributed cost
*Aviation Services** – provides aviation and travel services to employees.	Fully distributed cost
*Fleet** – oversees the Utility subsidiaries Fleet Services business unit.	Fully distributed cost
*Business Systems** – provides basic information technology services such as: application management, voice and data network operations and management, customer support services, problem management services, security administration, and systems management. In addition, Business Systems acts as a single point of contact for delivery of all information technology services to Xcel Energy. Business Systems partner with vendors to ensure the delivery of benchmarking, continuous improvement, and leadership around strategic initiatives and key developments in the marketplace.	Fully distributed cost

** Corporate Governance activities within this service function will be allocated using the average of the revenue ratio with intercompany dividends assigned to Xcel Energy Inc., full time equivalent hours including overtime, and the total assets ratio including Xcel Energy Inc.'s per book assets.*

V. COST ASSIGNMENT AND ALLOCATION PROCESS

OVERVIEW

This section of the CAAM provides an overview of the cost assignment and allocation principles of NSPM and the accounting processes within the monthly accounting close and within the general ledger, including both system generated processes and manual processes, used to assign and allocate costs between the regulated services and the non-regulated business activities of NSPM. Each major step of the accounting process is identified in the following paragraphs and will be explained in conjunction with the process flowchart of this section. Each major step results in costs being either directly assigned or allocated to regulated services and non-regulated business activities. The result of applying these principles is that each company, utility, jurisdiction and non-regulated business activity pays the full cost for any service provided to support their respective operations.

Many of the assignment and allocation processes occur in the Service Company or are administered by Service Company personnel. As noted in the Introduction, the Service Company provides services “at cost” to the Utility subsidiaries and affiliate companies.

The processes discussed in this section are integral to the financial books and records of NSPM and are included to provide a comprehensive picture.

COST ASSIGNMENT AND ALLOCATION PRINCIPLES

NSPM applies the following cost assignment and allocation principles. The cost assignment and allocation approach is a fully distributed costing method as approved by the Commission in NSPM’s electric and gas rates cases (E002/GR-92-1185, G002/GR-92-1186 and G002/GR-97-1606) and the Commission September 28, 1994 Order in Docket G, E-999/CI-90-1008.

The hierarchical cost assignment and allocation principles are:

I. Tariffed rate shall be used to value tariffed services provided.
II. Costs shall be directly assigned to either regulated or non-regulated business activities whenever possible.
III. Costs that cannot be directly assigned to either regulated or non-regulated activities or jurisdictions will be described as common costs. Common costs shall be grouped into homogeneous cost categories designed to facilitate the proper allocation of costs between regulated and non-regulated activities or jurisdictions in accordance with the following principles:
    a. Cost causation. All activities or jurisdictions that cause the cost to be incurred shall be allocated a portion of that cost. Direct assignment of a cost is preferred to the extent that the cost can be traced to the specific activity or jurisdiction.
    b. Variability. If the fully distributed cost study indicates a direct correlation exists between a change and the incurrence of a cost and cost causation, that cost shall be allocated based upon that relationship.

c. Traceability. A cost may be allocated using a measure that has a logical or observable correlation to all the activities or jurisdictions that case the cost to be incurred.
d. Benefit. All activities or jurisdictions that benefit from a cost shall be allocated a portion of that cost.

IV. Residual. The residual of costs left after either direct or indirect assignment or allocation shall be allocated based upon an appropriate general allocator as defined in this CAAM.

V. Whenever neither direct or indirect measures of cost causation can be found, the cost category shall be allocated based upon a general allocator.

A significant portion of NSPM's costs are incurred directly by NSPM. These costs are directly assigned or allocated based on the above principles to utilities, jurisdictions, and to non-regulated business activities. Utility allocations are described in Section VII and jurisdictional allocations are described in Section IX.

ACCOUNTING PROCESSES

The flowchart in this section provides a high-level overview of the major steps in the monthly accounting close process and the systems used to generate the financial books and records of NSPM. Several steps within the process have allocations imbedded within and are included to provide as much information as possible to promote an understanding of where direct assignment or allocations can occur.

Feeder Systems (Addendum A, Flowchart Item 1)

The monthly close process initially starts with the collection of accounting information from feeder systems as identified in Item 1 on the flowchart. Feeder systems gather accounting transactions on a daily, weekly or monthly basis and 'feed,' or pass, those accounting transactions to the general ledger within SAP.

SAP General Ledger System Processing (Addendum A, Flowchart Item 2)

Journal entries to record monthly transactions such as interest accruals, amortizations, cash transactions, receivables setup, etc., are entered directly into SAP using the SAP journal entry input screens. These journal entries also include the journal entries to record overheads on non-regulated business activities (see Section VII).

Once all the transactions from the processes identified above are recorded in SAP, there are multiple processing steps within SAP, including settlements and assessments. These processes affect regulated services and non-regulated business activities and are detailed separately on the following pages.

Settlements and Assessments (Addendum A, Flowchart Item 3)

All costs identified as billable are processed using the settlement and/or assessment processes of the SAP system. These processes bill transactions from the legal entity that performed the service to the legal entity that received or is responsible for the service. This process captures:

- Service Company direct and allocated billings of all its costs to affiliated interests;
- Direct billings between a utility subsidiary and an affiliated interest other than the Service Company which are often referred to as intercompany charges or billings; and
- Direct billings between business areas within a legal entity.

For example, the settlements process will settle Service Company labor to the affiliated company if the labor is a direct charge or it will send the charges to an ACC if the charge is to be allocated. The assessment process will then clear the ACC by allocating the charges using an approved method of allocation to the legal entities to which the employee is providing services along with the appropriate labor and labor-related overheads. Transactions between affiliates (excluding XES) are direct charges, as are charges from one business area to another business area (for example, charges from the Distribution Operations business area to the Energy Supply business area). After the settlements and assessment processes are completed, all costs reside on the books of the legal entity ultimately responsible for the charge in the appropriate FERC account.

Business View (Addendum A Flowchart Item 4)

The business view of the SAP general ledger provides a GAAP view of the accounting transactions necessary to prepare SEC financial statements and other GAAP financial reports as well as the information necessary for the business areas to manage the business.

FERC Account Data Prior to Utility and Non-Regulated Allocations (Addendum A Flowchart Item 5)

At the same time that the business view is available, the pre-allocated FERC view of the SAP general ledger is available. The following utility allocations and non-regulated allocations are necessary for common costs to be allocated to the gas, electric, and non-regulated businesses.

Utility Allocations and Non-regulated Allocations (Addendum A, Flowchart Item 6)

NSPM's costs are directly assigned or allocated to electric, gas, or non-regulated business activities whenever possible. When charges can't be directly assigned, they are charged as common and then allocated to the electric and gas utilities using utility allocations. Common utility costs are grouped into two categories: (1) O&M utility allocations and (2) rate base and non-O&M utility allocations. These allocations are performed monthly within the SAP system and are described in Section VII.

In addition to the costs directly assigned to the non-regulated business activities from the Service Company and within NSPM, the non-regulated business activities are charged with a labor related overhead and an allocation of corporate costs. See Section VIII for additional information related to non-regulated business activities.

All costs that can be directly assigned or allocated to the electric or gas utility operations or to the non-regulated business activities are appropriately accounted for in the books and records of NSPM before jurisdictional allocations occur. A study is performed annually, and as required for rate case filing purposes, to identify all rate base and non-O&M costs that are common among the jurisdictions of NSPM (Minnesota, North Dakota, and South Dakota). These costs are then allocated among the jurisdictions according to the allocations described in Section IX.

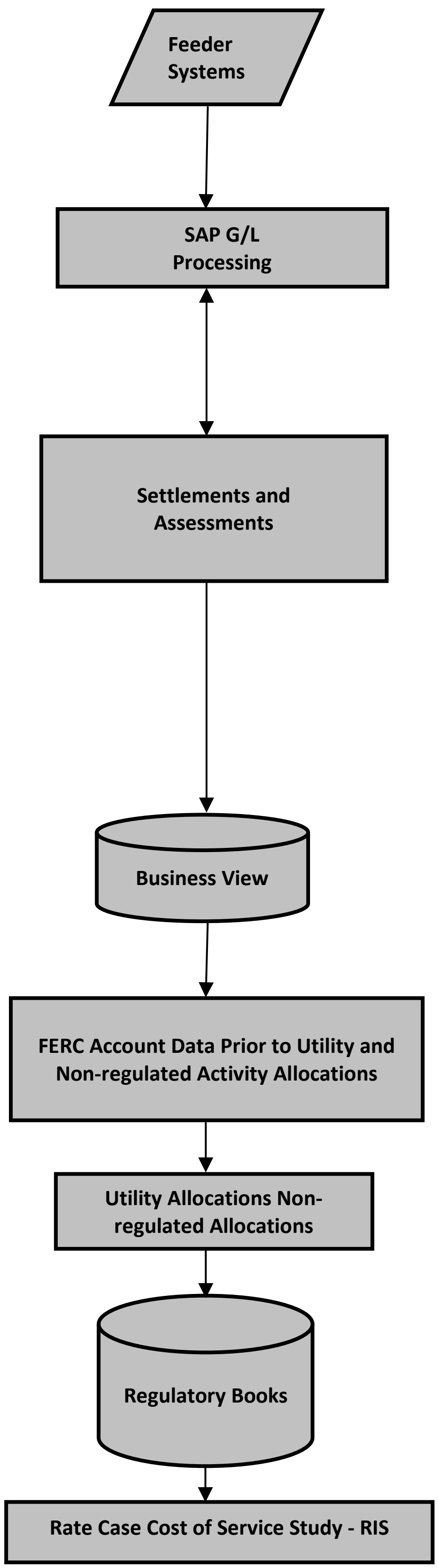
Regulatory Books and Records (Addendum A Flowchart Item 7)

After all the above processes are complete, the result is the FERC financial books and records of NSPM.

Rate Case Cost of Service Study (Addendum A Flowchart Item 8)

The FERC books and records are the starting point for the preparation of a cost of service study that will be used in a gas or electric rate case filing.

ADDENDUM A – PROCESS FLOWCHART



Item 1 – Feeder Systems
- **Labor Distribution**
- **Accounts Payable**
- **Money Pool**
- **Customer Billing**
- **Fixed Asset Ledger**

Item 2 – SAP general ledger system processing

Item 3 – Settlements and Assessments
- **Labor Overheads**
- **Aviation Distribution**
- **Stores/Warehouse Overheads**
- **Purchasing Overheads**
- **Fleet Distribution**
- **Information Technology**
- **Shared Asset Distribution**
- **Facilities Distribution**
- **Engineering & Supervision**
- **Capital A&G**

Item 4 – Business View

Item 5 – FERC account data prior to Utility and Non-regulated activity allocations

Item 6 – Utility Allocations and Non-regulated allocations

Item 7 – Regulated books and records

Item 8 – Rate case cost of service study - Rate Information System ("RIS")

Feeder and Overhead System Detail

LABOR DISTRIBUTION

Description:	Wages and salaries of employees engaged in work on behalf of regulated services and non-regulated activities are assigned or allocated based on positive time reporting through the labor distribution system. Positive time reporting requires each employee to report the hours worked for each day using one-tenth of an hour or greater increments, while providing for aggregation of time when appropriate. Under this method, employees' time is reported on the basis of accounting codes related to specific operating utility companies or affiliates and/or functional services.
Provider of Service:	Service Company Operating companies or affiliates
User of Service:	Operating companies or affiliates, including utility operations, jurisdictions, and non-regulated activities within an operating company.
Method of Allocation:	All bi-weekly and semi-monthly employees' labor expenses are recorded by company personnel on time sheets and entered into the time reporting system, which feeds into the labor distribution system. The employee submitting the time sheet is responsible for coding the internal order numbers to charge the appropriate operating companies or affiliates, business function (e.g., capital, operations, maintenance, clearing, purchasing and/or warehousing, etc.) and regulated or non-regulated operations. Time must be completed and submitted for review and approval by certain cut-off dates established by the Payroll Department. The employee's supervisor or manager is responsible for reviewing and approving all time entries and verifying that the employee is using the correct accounting. The labor distribution system used for bi-weekly employees includes the distribution of actual paid and accrued labor dollars/hours to the internal order number charged based on the hours worked. Accrual of payroll is to facilitate the recording of labor costs on a calendar month basis. This includes any reversal of the prior month's accrual. The charge of labor dollars for semi-monthly employees to internal order numbers is based on a distribution of the monthly salary of the employee.

LABOR OVERHEADS

Description:

Employee labor overhead costs are captured in the following categories:

Benefit employees:

- Non-productive labor costs (vacation, sick, holiday, etc.)
- Pension and Insurance (401k match, retirement related consulting, active healthcare, life and LTD insurance premiums, miscellaneous benefit programs and LTD benefits for former or inactive employees before retirement, as well as the service cost portion of qualified pension, non-qualified pension and retiree healthcare)
- Benefits Non-Service (non-service cost portion of qualified pension, non-qualified pension and retiree healthcare)
- Workers compensation (FAS 112 actuarial cost and insurance premiums)
- Incentives (Incentives are a labor overhead for Service Company, PSCo, and SPS. Incentives for NSPM and NSPW are charged directly to FERC accounts 920 and 517).
- Payroll taxes (FICA, FUTA, SUTA)
- Labor and expense of the Human Resource Service Center

Non-Benefit employees:

- Payroll taxes (FICA, FUTA, SUTA)
- Workers compensation

Provider of Service:

Service Company
Operating companies or affiliates

User of Service:

Operating companies or affiliates, including utility operations, jurisdictions, and non-regulated activities within an operating company.

Method of Allocation:

Labor overheads are allocated within a legal entity by calculating a separate loading rate for each cost category identified in the "Description" section above.

For each legal entity and each category, the costs are allocated based on a single-factor formula that is comprised of total estimated costs for the category divided by total estimated productive labor costs.

Legal entity specific rates for each category are applied to productive labor charges as appropriate for each resource type. Labor loadings applied to labor charges follow the labor charges. For example, Service Company labor overheads follow Service Company labor and NSPM labor overheads follow NSPM labor.

AVIATION DISTRIBUTION

Description:	The Aviation Services department in the Service Company is responsible for managing and operating the two corporate leased aircraft used by the Xcel Energy. Costs include: pilot salaries including labor overheads, O&M costs, lease costs, and A&G costs associated with managing the Aviation Services department.
Provider of Service:	Service Company
User of Service:	Service Company, operating companies or affiliates, including utility operations, jurisdictions, and non-regulated activities within an operating company.
Method of Allocation:	Aviation costs are allocated using the average of the Revenue Ratio with intercompany dividends assigned to Xcel Energy Inc., Full Time Equivalent Hours Including Overtime, and the Total Assets Ratio including Xcel Energy Inc.'s per book assets. Any spousal use of the aircraft must be approved and is billed to Xcel Energy Inc.

STORES/WAREHOUSE OVERHEAD

Description:	Inventory warehousing costs, including labor, supervision, materials and supplies are allocated through pools to the business areas as an overhead on materials and supplies as materials and supplies are issued from/returned to a storeroom or warehouse.
Provider of Service:	Service Company Operating companies
User of Service:	Operating companies or affiliates, including utility operations, jurisdictions, and non-regulated activities within an operating company.
Method of Allocation:	The overhead costs for inventory items as noted above and associated adjustments are accumulated within the Supply Chain warehouse ACC's. These accumulated overhead costs are allocated to material issuances/returns from the storeroom. Costs are collected in ACC's on the Service Company and Operating Companies; then cleared using a warehouse overhead loading based on a costing sheet, cost element and AP document type criterion.

PURCHASING OVERHEAD

Description:	The Supply Chain organization in the Service Company has the responsibility for distributing the corporate purchasing and contract services costs to the functional area(s) of the operating companies or affiliates along with the cost of the materials and supplies ordered. Purchasing costs are made up of activities such as developing requisitions, contracts and purchase orders to procure materials and services and manage supplier relationships, negotiating complex procurement agreements/contracts for strategic supplier partnerships and service contracts, monitoring supplier performance, and managing purchase records, supplier qualification records, supplier diversity program, and support, maintenance, and performance monitoring of key applications and metrics used throughout the purchasing process. The Supply Chain organization is supported by specific Human Resources personnel who assist with supplier qualification processes as well as by the Enterprise Security department who manages the Security Vendor Risk Assessment process.
Provider of Service:	Service Company Operating companies
User of Service:	Service Company, operating companies and affiliates, including utility operations, jurisdictions, and non-regulated business activities within an operating company.
Method of Allocation:	Costs are collected in ACC's on the Service Company and the operating companies and cleared using an overhead loading based on costing sheet, cost element, and AP document type criterion.

FLEET DISTRIBUTION

Description:	The Fleet Services department in the Service Company is responsible for managing the fleet assets owned by the operating companies. Fleet assets are vehicle units that are organized into fleet work centers, which group together vehicles similar in nature for a specific business function within an Operating Company. . The SAP Work Manager records the utilization of our fleet assets and allocates the cost to the business areas of operating companies and affiliates for the costs of using vehicles or associated equipment using fleet activity rates based on work centers. Fleet costs included in the calculation of the monthly billing rate include: licensing taxes and fees, lease costs, material and labor costs for maintenance and repair, fuel, labor loadings, and overhead for overall management of the Fleet Services department that includes labor, facilities, insurance, utilities, computers, phones, and office supplies.
Provider of Service:	Service Company Operating companies
User of Service:	Service Company, operating companies or affiliates, including utility operations, jurisdictions and non-regulated business activities within an operating company.
Method of Allocation:	Costs are collected in ACC's on the Service Company and operating companies which are cleared using an overhead fleet rate based on the weighted vehicle type to the respective business area.

INFORMATION TECHNOLOGY

Description: The Business Systems organization in the Service Company is responsible for managing the corporate IT assets and services of Xcel Energy. Business Systems bills out O&M and capital costs related to Xcel Energy's corporate IT equipment and services incurred internally, as well as costs incurred through third party vendors. Costs include system O&M, desktop services, phone service, servers, infrastructure costs, software, software licensing, system design and implementation, labor and labor overheads, etc.

Provider of Service: Service Company

User of Service: Service Company, operating companies, or affiliates, including utility operations, jurisdictions and non-regulated activities within an operating company.

Method of Allocation: IT costs are charged through several different methods.

Costs are charged directly to the operating companies, affiliates, jurisdictions or non-regulated activities on the invoice, timesheet, expense report or other source document to the company(ies) benefiting from the service whenever possible.

If costs cannot be charged directly to an operating company, affiliate, jurisdiction or non-regulated activity, the costs are charged to the appropriate Service Company indirect ACC that will assign the costs using a cost causative method to the companies benefiting from the system, application, or service.

For costs that can be identified as benefiting a particular service function, those services would be charged to a Service Company indirect ACC using the approved allocation factor for that business area.

If an indirect ACC cannot be identified that would assign costs in a cost causative method, a new indirect ACC will be created. However, if the project will be in-serviced within one year and if O&M costs will be less than $250,000 in total for the project, an internal order will be used to assign costs using a cost causative method to the companies benefiting from the system, application, or service.

ACCOUNTS PAYABLE

Description:	The Payment and Reporting Department (Accounts Payable), in the Service Company, processes several types of documents for payment on behalf of the operating companies and affiliates. Accounts Payable uses SAP to process invoice payments associated with purchase orders, contracts, requests for payment (non-purchase orders, non-contract invoices) and employee payments, including per diem charges, suggestion system award payments and employee expense reimbursements. The charges for goods, materials and services, which post directly to the general ledger of each operating company and affiliate, differ for each type of document.
Provider of Service:	Service Company
User of Service:	Service Company, operating companies and affiliates, including utility operations, jurisdictions, and non-regulated activities within an operating company.
Method of Allocation:	Within each operating company and affiliate, charges are directly assigned whenever possible. Charges may be distributed to multiple business functions or business areas based on the accounting code(s) on each document. If necessary, costs may be allocated using any surrogate measure that has a logical or observable correlation to the charges in the quantities sold, the services that caused the cost to be incurred or that benefited from the cost. The following are examples of some of the logical or observable correlations used to allocate costs contained on Accounts Payable documents: • Quantity (units, count, etc.) • Measurement or size (length, space, columnar inch, etc.) • Volume (barrels, gallons, liters, etc.) • Weight (ounce, pound, ton, etc.) • Hours (hours of professional or contract services) • Labor dollars (charge is in the same proportion as the labor hours of the department) • Number of customers, meters, employees, etc. • Revenue dollars • Plant in service • Square footage

SHARED ASSETS DISTRIBUTION

Description:	Shared assets are defined as capitalized assets that are owned by one legal entity but are used for the benefit of multiple entities. This would include land structures and improvements, office furniture and equipment, computer and communication equipment, and some software systems that are used by employees in the performance of their jobs.
Provider of Service:	Operating companies or affiliates
User of Service:	Service Company, operating companies and affiliates
Method of Allocation:	All allocations are billed through the Service Company and charged to a Service Company internal order that will assign the costs using a cost causative method to the companies benefiting shared assets. For IT related assets, the costs will be charged to the system application or service internal order. For facility assets, the costs will be charged to the respective Service Company facilities ACC that will assign the costs following employee labor.

FACILITIES DISTRIBUTION

Description:

Facilities costs are assigned or allocated to the functional areas of operating companies and other affiliates who benefit from the use of the facilities. Depending on whether a building is used by one utility company or is a “shared” building, i.e., building used by employees of more than one operating company or affiliate, facility costs may include:

Single-utility facility:
The administrative property services labor and non-labor costs, utility expenses, maintenance costs for structures and systems, pro-rated share of property taxes (for owned buildings), and the rent and occupancy expenses (for leased buildings).

Shared facility:
Administrative property services labor and non-labor costs, utilities expenses, and the maintenance costs for structures and systems are captured. If the building is leased, the rent is included. If the building is owned, the carrying costs of the shared assets, such as the depreciation and a return on rate base, are included in the facilities’ cost.

The Property Services department is responsible for the owned and leased facility.

Provider of Service: Service Company or operating companies

User of Service: Service Company, operating companies, and affiliates

Method of Allocation:

Costs for a single-utility facility are accumulated in the ACC of the company benefitting from the use of the building and are then allocated to functional FERC rent accounts based on the most recent quarter’s labor charges.

Costs related to a shared facility, i.e., buildings used by employees of more than one operating company or affiliate, are first accumulated in ACC’s specific to the shared facility and then distributed to each operating company and affiliate based upon the most recent quarter’s labor for the specific employees located in each facility. Once costs are assigned to the appropriate company, they are then allocated to the functional FERC rent accounts based on the most recent quarter’s labor charges.

MONEY POOL

Description:	Through the Utility Money Pool ("UMP"), temporary surplus funds of Xcel Energy are available for short-term loans to other operating companies with cash needs.
Provider of Service:	Service Company
User of Service:	Operating companies
Method of Allocation:	An operating company can borrow from, and make loans to, the UMP, which is administered at cost by the Service Company. In addition, Xcel Energy Inc., the Holding Company, can deposit surplus funds into the UMP but cannot borrow from the UMP. Interest income or expense is charged or credited, as appropriate, to the UMP participants. All charges are directly billed from the Service Company to the appropriate operating company. NSPM petitioned for and received approval on the use of a UMP in Docket No. AI-04-100.

CUSTOMER BILLING

Description:	NSPM bills customers for electric, gas, propane, and miscellaneous non-regulated activities through the customer billing system.
Provider of Service:	Operating companies
User of Service:	Operating companies, including utility operations, jurisdictions, and non-regulated activities.
Method of Allocation:	Costs related to customer billing are direct charged to specific operating companies whenever possible. When costs cannot be directly assigned to a specific operating company, they are allocated based on the number of customers. Non-regulated activities that use the customer billing system are allocated a customer accounting overhead based on revenue dollars. See Section VII.

ENGINEERING AND SUPERVISION ("E&S") OVERHEAD

Description:	E&S costs are capitalized as construction overheads. E&S overheads are applied where it is not practical to direct charge the pay and expense of the engineers, surveyors, draftsmen, inspectors, first line management, and their assistants to construction. NSPM uses the E&S overhead allocation to charge these expenses to capital projects.
Provider of Service:	Operating companies and Service Company
User of Service:	Operating companies.
Method of Allocation:	Costs related to E&S are gathered in an ACC separately by functional class and utility (production, transmission, and distribution). The ACC's are fully allocated on a monthly basis to clear the balances to zero. These costs are sent to the fixed asset ledger and then are allocated to each eligible capital internal order based on current month charges and the calculated rate. The fixed asset ledger tracks all capital projects and work order expenditures for Xcel Energy on a life-to-date basis. Once expenditures are recorded on the books of the appropriate legal entity, the fixed asset ledger system generates the overhead allocations, and if appropriate, AFUDC, which are then applied to the individual internal orders. In addition, the fixed asset ledger calculates monthly depreciation by legal entity and handles the transfer of work orders from FERC account 107, Construction Work in Progress; to FERC account 106, Completed Construction-Not Unitized; to FERC account 101, Utility Plant in Service. The transfer of non-utility costs is within FERC account 121, Non-Utility Property using sub accounts.

CAPITAL A&G

Description:	A&G costs are capitalized as construction overheads. The overhead relates to all the personnel in the administrative office that work on construction to assure its continued operation but are not direct to any one project. A prime example is the payroll analyst whose responsibility it is to assure the construction labor receives its payroll checks. Because it is inefficient for these employees to direct charge all the work orders an overhead process is used to facilitate charging the capital work orders.
Provider of Service:	Operating companies and Service Company
User of Service:	Operating companies.
Method of Allocation:	Each operating company performs an A&G study every other year to review the time employees in certain administrative departments spend on capital work. A percent of payroll for these employees, based on the A&G study results is charged to an overhead allocating cost center, one-twelfth each month. The overhead cost center is allocated to each work order based on current month charges.

VI. UTILITY ALLOCATIONS

OVERVIEW

NSPM's costs are directly assigned or allocated to electric, gas, or non-regulated activities whenever possible or charged as common and then allocated to the electric and gas utilities using utility allocations. Common utility costs are grouped into two categories: (1) O&M utility allocations and (2) rate base and non-O&M utility allocations. The O&M utility allocations are processed monthly within SAP and are explained below. The common rate base and non-O&M utility allocations are completed as part of an annual study and for rate case filing purposes which are explained below.

O&M UTILITY ALLOCATIONS

Introduction

Common O&M utility allocations are applied to common costs that are recorded in A&G (FERC accounts 920-935), customer accounting, and customer information and sales (FERC accounts 901-917). Table A in this section lists the NSPM allocation methodology applied to each FERC account or range of FERC accounts.

Methodology

NSPM uses the following methods to allocate common O&M costs. These methods were developed to achieve the most cost causative relationship that each FERC account or range of FERC accounts has with electric and gas utility operations. The allocators used are as follows:

Customer Allocator

The customer allocator is used to allocate common utility costs in FERC accounts 901-903, and the non-commodity bad debt portion of FERC 904 and 905-917 among electric and gas operations. The allocation is based on the customer bill counts for the electric and gas utilities. The allocator used in the current year is developed based on the previous years' actual customer bill count.

Revenue Allocator

The revenue allocator is used to allocate common utility costs for commodity bad debt, recorded in FERC account 904, among electric and gas operations. The allocation is based on a rolling four-year average of actual electric and gas revenues. The allocator in the current year is developed based on the four previous years' actual operating revenues from the corporate income statement.

Three-Factor Allocator

The three-factor allocator is used to allocate common utility costs in FERC account ranges 920-924 and 927-935 among electric and gas utilities. The allocation is based on the weighted average of operating revenue, plant in service, and supervised O&M. The allocator used in the current year is developed based on the previous years' actual operating revenue, plant in service and supervised O&M.

Labor Allocator

The labor allocator is used to allocate common utility costs in FERC accounts 925-926 to the electric and gas departments. The allocation is based on operating labor for the electric and gas utilities. The allocator used in the current year is developed based on the previous years' actual operating labor.

RATE BASE AND NON-O&M UTILITY ALLOCATIONS

Introduction

A study is performed annually, and for rate case filing purposes, to identify all rate base and non-O&M costs that are common among the utility operations of NSPM in order to allocate them to the electric and gas utilities.

Methodology

NSPM uses the following methodology to allocate common rate base and non-O&M costs. These allocation factors were developed to achieve the most cost causative methodology based on the pool of costs being allocated. Table B in this section lists the methodology applied to specific pools of costs. The allocators used are as follows:

Three-Factor Allocator

The allocation is based on the weighted average of operating revenue, plant in service, and supervised O&M. The allocator used in the current year is developed based on the previous years' actual operating revenue, plant in service and supervised O&M.

Computer Software Study

A composite allocator is used to allocate common computer software rate base (plant) and non-O&M (plant related) costs among electric and gas utilities. Software assets and related costs are presented in a cost of service study using a single amount. A study of all computer software is done to determine how each individual software asset that is part of the single amount should be allocated. All individual allocations are summarized to create a single composite allocation that is then applied to the summarized computer software plant and plant related costs.

Transportation Study

Individual allocators are used to allocate common transportation rate base (plant) and non-O&M (plant related) costs among electric and gas utilities. Transportation assets are reviewed to determine where vehicles are used and allocation factors are developed.

Table A – O&M Utility Allocations

FERC Account	Allocation Method	Basis for Allocation Selection
901-917 (excluding commodity bad debt in FERC 904)	Customer Allocator	Customer bill counts are a reasonable methodology to use to allocate common customer accounting and customer information and sales costs recorded in FERC accounts 901-917 because these costs are customer related costs, e.g., credit and collection, customer accounting, bad debt, etc.
904 (commodity bad debt portion)	Revenue Allocator	A revenue allocator is a reasonable methodology to allocate commodity bad debt because these costs have a cost-causative relationship to uncollectible utility revenues.
920-924	Three-factor Allocator	A three-factor allocation is reasonable because there is no single allocator that could provide a cost-causative link. A three-factor allocator that measures three distinct aspects of the Company and results in an overall fair assignment of costs to the electric and gas utilities is used and is based on equally weighting operating revenue, plant in service and supervised O&M.
925-926	Labor Allocator	A labor allocation is reasonable because the costs recorded in these accounts are injuries and damages and pension and benefit costs. These costs have a cost-causative relationship with labor.
927-935	Three-factor Allocator	A three-factor allocation is reasonable because there is no single allocator that could provide a cost causative link. A three-factor allocator that measures three distinct aspects of the Company and results in an overall fair assignment of costs to the electric and gas utilities is used and is based on equally weighting operating revenue, plant in service and supervised O&M.

Table B – Rate Base and Non-O&M Utility Allocations

Utility	Functional Class	Pool of Costs	Allocation Methodology
Electric			Direct Assignment
Gas			Direct Assignment
Common	26/Common Intangible Plant	Computer Software	Computer Software Study
Common	31/Common General Plant	General Furniture & Equipment	Three-Factor Allocation
Common	31/Common General Plant	Electric Distribution – Mass – MN	Direct Assignment to Electric
Common	31/Common General Plant	Electric Distribution – ND	Direct Assignment to Electric
Common	31/Common General Plant	Electric Distribution – MN	Direct Assignment to Electric
Common	31/Common General Plant	Electric Distribution Vaults	Direct Assignment to Electric
Common	31/Common General Plant	Allen S King Plant	Direct Assignment to Electric
Common	31/Common General Plant	Electric Transmission Line – MN	Direct Assignment to Electric
Common	31/Common General Plant	Electric Transmission Substation – MN	Direct Assignment to Electric
Common	31/Common General Plant	Gas Distribution – MN	Direct Assignment to Gas
Common	31/Common General Plant	General Tools and Other Equipment	Three-Factor Allocation
Common	31/Common General Plant	Office, Service & Other Bldgs – MN	Three-Factor Allocation
Common	31/Common General Plant	Office, Service & Other Bldgs – ND	Three-Factor Allocation
Common	31/Common General Plant	Office, Service & Other Bldgs – SD	Three-Factor Allocation
Common	31/Common General Plant	Software – Minnesota	Three-Factor Allocation
Common	31/Common General Plant	Transportation Equipment – MN	Transportation Study
Common	31/Common General Plant	Transportation Equipment – MN	Transportation Study
Common	31/Common General Plant	Transportation Equipment – SD	Transportation Study
Common	31/Common General Plant	Prairie Island	Direct Assignment to Electric
Common	31/Common General Plant	Inver Hills – Prod Other	Direct Assignment to Electric
Common	31/Common General Plant	Big Oaks Rec Area	Three-Factor Allocation
Common	31/Common General Plant	Black Dog	Direct Assignment to Electric
Common	31/Common General Plant	High Bridge	Direct Assignment to Electric
Common	31/Common General Plant	Riverside	Direct Assignment to Electric
Common	31/Common General Plant	Sherco	Direct Assignment to Electric
Common	31/Common General Plant	Gas Prod – Wescott – MN	Direct Assignment to Gas
Common	31/Common General Plant	General Tools and Other Equipment	Three-Factor Allocation
Common	31/Common General Plant	General Plant – MN	Three-Factor Allocation
Common	31/Common General Plant	General Plant – SD	Three-Factor Allocation
Common	31/Common General Plant	General Plant – ND	Three-Factor Allocation

VII. NON-REGULATED ACTIVITY ALLOCATIONS

INTRODUCTION

The purpose of this section is to detail the methods of assigning and allocating costs between the regulated services and the non-regulated activities of NSPM.

NSPM follows the same approach for all types of costs for its fully distributed costing method. As discussed earlier in the CAAM, NSPM's method was approved by the Commission in its electric and gas rate cases (E002-GR-92-1185, G002-GR-92-1186 and G002/GR-97-1606) and the Commission's September 28, 1994 Order in Docket No. G,E-999/CI-90-1008.

The Commission established the following hierarchical cost assignment and allocation principles in Docket No. G,E-999/CI-90- 1008:

1. Tariffed rate shall be used to value tariffed services provided to non-regulated activities.
2. Costs shall be directly assigned to either regulated or non-regulated activities whenever possible.
3. Costs that cannot be directly assigned are common costs, which shall be grouped into homogenous cost categories. Each cost category shall be allocated based on direct analysis of the origin of the costs whenever possible. If direct analysis is not possible, common costs shall be allocated based upon an indirect cost causation.
4. Whenever neither direct or indirect measures of cost causation can be found, the cost category shall be allocated based upon a general allocator.

This process accomplishes the proper separation of costs between NSPM's regulated utility business and non-regulated activities. Each activity that could be considered as being outside of NSPM's electric and gas business is reviewed for regulated/non-regulated treatment. If the activity is approved to be treated as a non-regulated operation, the non-regulated cost allocation process is followed.

There are limited situations where an activity that would be in the public interest could not be pursued if a fully distributed costing approach was followed. In such circumstances, NSPM has filed, and will continue to file, any deviation from a fully distributed costing process on a project-specific basis. Any existing exceptions have been filed and approved by the Commission.

Evaluation Process

NSPM's approach to fully distributed costing includes the following steps of analysis: business profile, direct charging, labor overheads, cost causation allocation, labor related overhead, and corporate residual allocation. Non-NSPM affiliates are charged a working capital fee as discussed in Section IV.

Business Profile

The allocation process begins by reviewing each non-regulated activity for the services NSPM's utility business will be providing to the non-regulated activity.

Direct Charging (Addresses Principle #2)

Cross charges between NSPM service providers and non-regulated activities are reviewed with the business. Any process, project, or service performed for the direct benefit of a non-regulated activity is directly charged to the non-regulated activity. The business area providing service to the non-regulated activity communicates the anticipated level of service and how much the service will cost.

Labor charges are directly assigned to the non-regulated activity within the budgeting process, generally based on historical charges and taking into consideration known changes. The non-labor charges are directly charged. This process enables charging for all service that will be provided.

Cost Causation Allocations (Addresses Principle #3)

If no direct charge has been established for a service expected to be provided, a cost causation allocation is developed. Direct charging is preferred. However, if a service is expected to be provided and was not budgeted as a direct charge, an estimate of the cost of the service is made and allocated to the non-regulated business. An example of this would be, when a service is being provided, but it is at such a minimal level that it would be very difficult or cost prohibitive to charge on a direct basis.

Overhead Costs (Addresses Principle #4)

The overhead allocation factors capture indirect costs associated with providing services to non-regulated activities.

NSPM currently uses a labor overhead rate developed by reviewing the expenses incurred in support of employee related activities (such as employee programs, employee relations, training, employment, compensation and benefits program development costs, diversity, safety), office equipment needs, and supervision of the service provider. The labor overhead is applied to fully loaded labor. The labor related overhead is applied to non-regulated services wholly contained within NSPM and affiliate or third party transactions.

For non-regulated services wholly contained within NSPM, a portion of NSPM's corporation costs are allocated based on a two-factor formula that takes into consideration the relative size of the non-regulated business by using number of employees and revenues.

Most non-regulated activities are also allocated a portion of NSPM's common Customer Accounting Costs. The distinction here is whether the non-regulated activity uses the customer accounting services of NSPM. For those activities that do use these services, common Customer Accounting Costs are allocated on the basis of revenues earned by each non-regulated activity. The Company utilizes revenue dollars for regulated activities and non-regulated activities to allocate the common portion of Customer Accounting Costs, recorded in FERC accounts 901-916, to the non-regulated activities. Excluded from the Common Costs in FERC accounts 901-916 are: FERC account 902, Meter Reading Expenses; FERC account 904, Uncollectible Accounts; and CIP costs in FERC account 908, Customer Assistance Expenses. These costs have been excluded because they are not pertinent to NSPM's non-regulated activities, as the non-regulated activities account for their own bad debt expenses separately.

Working Capital Fee (Addresses Principle #3)

The working capital fee is applied to non-NSPM affiliates. The fee is based on the current Prime Rate and is reviewed and updated quarterly. This fee is to compensate the regulated business for the cost of working capital used by affiliates.

VIII. JURISDICTIONAL ALLOCATIONS

INTRODUCTION

NSPM's methods for assigning and allocating common O&M costs, plant and plant related, and other rate base investment to jurisdictions is intended to distribute costs in a manner that most closely reflects the benefit received from the expenditure. Accurately stating the assigned and allocated costs of the Company, as they relate to causation of the costs, is a fundamental part of creating a fair distribution of those costs to jurisdiction.

NSPM uses three methods to assign and allocate O&M expense, plant and plant related, and other rate base investment to jurisdiction:

1. direct assignment based on FERC account and location,
2. allocate based on cost causation, and
3. allocate based on a default allocator.

Determination of the assignment and allocation of costs to jurisdiction is an annual process designed to identify the jurisdiction(s) that receive the benefit from the cost or investment. During the review, the three methods stated above are used to ensure that the appropriate jurisdiction(s) is assigned or allocated the cost. It is NSPM's primary goal to direct assign or allocate based on cost causation as often as possible, and allocate based on a default as little as possible.

The first step in assigning costs and investments to a jurisdiction is to identify all costs that can be directly assigned to a jurisdiction (Minnesota, North Dakota or South Dakota), based on the location where work is being performed. For O&M expense, the SAP general ledger account has a location indicator (Profit Center) and a FERC account number associated with it and these are used to determine the appropriate jurisdiction(s) for assigning costs. The individual business areas determine and maintain the appropriate values for these codes based on the type of work being performed and which customers benefit from it. For plant investment data, the PowerPlan system's functional class ID, state code and the function that it is serving are used to determine the appropriate jurisdictions to assign costs for plant, plant related and other rate base costs.

Direct Assignment Based on FERC Account and Location

The first method NSPM uses is to direct assign costs whenever possible. For example, the distribution portion of an electric substation (that which is assigned to a distribution FERC account function) and is located in the Twin Cities metro area can be directly assigned to the Minnesota jurisdiction based on location as it directly serves only customers in Minnesota. In addition, all gas transmission and distribution property are directly assigned to the jurisdiction based on where the property is located as defined within the PowerPlan system. The Capital Asset Accounting organization maintains the capitalized property data.

An O&M example of direct assignment (expense) would be either electric or gas special meter reading done in the Twin Cities metro area (assigned to a distribution FERC account). The meters read are for customers in the State of Minnesota; therefore, the related costs are directly assigned to the Minnesota jurisdiction.

All regulatory expenses specific to a jurisdiction are directly assigned to that jurisdiction. For example, indirect assessments charged to NSPM, from the Minnesota Department of Commerce and the Commission, are directly assigned to the Minnesota jurisdiction.

Allocation Based on Cost Causal Relationship

The second method NSPM uses identifies all investments and costs that can be assigned to jurisdiction based on a causal relationship, and allocates these costs using the most cost causal allocation method. Examples of electric and gas analyses are as follows:

Electric

NSPM operates an integrated electric transmission system that transports electricity to NSPM's distribution system that in turn, supplies electricity to all of NSPM's customers. The transmission system is built to meet the demand created by serving its customers and, therefore, NSPM uses a coincident peak transmission demand taken from twelve consecutive months that constitute a calendar year method, to allocate transmission investment to all of its jurisdictions. All of the expense and plant investment, assigned to transmission function, exists to support NSPM's infrastructure, is fixed in nature and is assigned to jurisdiction based on transmission demand.

The cost causation allocators used for electric production expense or plant investment is a twelve-month coincident peak demand or energy, depending on the type of expense or plant investment. If the expense is variable in nature, energy is used to make the assignment to jurisdiction. If it is determined that the expense or plant investment exists to support NSPM's infrastructure and is fixed in nature, the demand allocator is used to make the assignment to jurisdiction.

Gas

From a supply standpoint, for example, NSPM operates its gas distribution system as a single unit. NSPM purchases natural gas, pipeline delivery capacity, and transmission of gas purchased to meet its customers' requirements on a system-wide basis. In addition, NSPM also operates propane-air (LPG) peak shaving facilities and liquefied natural gas (LNG) peaking facilities to meet firm demand in excess of natural gas daily pipeline entitlement for the benefit of the entire NSPM system. Because these types of costs support the entire operating company system, it is not possible to direct assign them to a specific jurisdiction. For this example, the O&M production and storage functions are allocated to jurisdiction based on the type of expense within the FERC account number. The transmission function is allocated based on the gas load dispatch allocator that is a combination of the design day firm demand allocator and total annual throughput. For plant investment, all production and storage facilities are allocated based on the gas design day allocator related to the design day firm demand.

Electric & Gas

Cost and investment in support of NSPM's distribution, customer accounting, and customer information & sales are more easily identified by state based on the location or where the work is being performed, or they can be allocated to jurisdiction using customers as a basis. In cases where services are provided and serve all regional customers, a regional allocator is developed which reflects the number of customers served in Minnesota and North Dakota or Minnesota and South Dakota, depending on the region. This represents a causal relationship between costs incurred in those regions and the assignment of costs to jurisdiction. Locating services performed in the Fargo area is an example of these types of costs. Locating services are performed for customers on both sides of the Minnesota/North Dakota border and are, therefore allocated to jurisdiction based on the number of year-end average customers in the North Dakota Region, which includes Fargo, Moorhead, Grand Forks, East Grand Forks and Minot.

Allocation Based on a Default Allocator

Allocation of common and general investment or A&G expense: costs and investment that cannot be assigned to jurisdiction using either direct assignment or allocation based on cost causation as described above are allocated to jurisdiction using a default allocator.

Common and General Plant Investment

The default allocator for electric plant investment is determined by the function that it serves. Common and general plant that serves production uses a twelve-month coincident peak demand allocator to allocate costs to jurisdiction. Plant serving transmission uses a twelve-month coincident peak transmission demand allocator to allocate costs to jurisdiction. For plant serving distribution, the number of year-end average customers is used to allocate costs to jurisdiction.

For Gas plant a default allocator is also determined by the function that it serves. For general and common plant, a year-end average customer allocator is used as the default. If the investment function has been determined to be gas production related, then the default jurisdictional allocator used in the production allocator is gas design day.

Administrative and General Expenses

When assigning or allocating A&G expenses to jurisdiction, a cost causative allocator is used if a functional relationship is easily established. In other instances, Electric A&G costs are allocated to jurisdiction using an equally weighted two-factor allocator based on electric plant in service and electric O&M expense (excluding A&G). The two factor allocator is developed by first calculating a three part historical ratio of plant investment directly serving production, transmission or distribution and a three part historical ratio of O&M expenses assigned to FERC accounts that are either production, transmission or directly serve customers (distribution, customer accounting, customer information or sales). These two ratios are then averaged to develop an equally weighted production, transmission and distribution ratio. This resulting three part ratio is then multiplied times the jurisdictional O&M default allocation ratios. The electric production portion is allocated to jurisdiction using a twelve-month coincident peak demand allocator; the transmission portion using the transmission demand allocator; and the customer portion is allocated using twelve-month end-of-year customers. The final step is to add the three sets of jurisdictional ratios together to form the two factor jurisdictional allocator used to allocate electric A&G costs supporting corporate functions.

Gas A&G expenses are allocated to jurisdiction using the appropriate customer allocation as a default allocator, based on the SAP account location indicator (profit center).

A more detailed description of each allocation type and method of allocation, including examples of why the allocation was chosen to assign costs to jurisdiction is included below.
Table C in this section lists the methodology applied to specific pools of costs.

ALLOCATION METHODS

GAS & ELECTRIC

Allocation: Direct Assigned

This allocation type is used to assign all expenses that are determined to be directly assignable to a jurisdiction (Minnesota, North Dakota, and South Dakota).

Allocation: Direct Assigned: State of Minnesota

This allocation type is used for all expenses that are determined to be for the direct benefit or in direct support of the Minnesota jurisdiction. The types of costs direct assigned include: direct and indirect assessments related to one of Minnesota's regulatory bodies, legal department expense budgeted in support of Minnesota, economic development activities in the state of Minnesota, facilities expenses in support of the distribution business unit in the state of Minnesota, delivery system operation and maintenance costs in the Twin Cities metro area, Northwest and Southeast regions and automated energy system (AES) expenses.

Allocation: Direct Assigned: State of North Dakota

This allocation type is used for all expenses that are determined to be for the direct benefit or in direct support of the state of North Dakota jurisdiction. The types of costs direct assigned include: regulatory development activities based out of the North Dakota regional offices, direct and indirect assessments related to the North Dakota regulatory bodies, legal department expenses budgeted in support of North Dakota, economic development activities performed directly for North Dakota and work performed in the Minot area for the sole benefit of North Dakota customers.

Allocation: Direct Assigned: State of South Dakota

This allocation type is used for all expenses that are determined to be for the direct benefit or in direct support of the state of South Dakota jurisdiction. The types of costs direct assigned include: direct and indirect assessments related to the South Dakota regulatory bodies, legal department expenses budgeted in support of South Dakota, economic development activities performed directly for South Dakota.

Allocation: Customers - Year-End Average - (Electric or Gas)

This allocation type is used to assign expenses where there is a cost causative relationship between the number of electric and gas utility NSP customers in a particular area and the service provided. This allocator is based on year-end average customer by utility.

Allocation: Customers Year-End Average Minnesota Co. MN/ND/SD

This allocation type is used to assign costs to all of Minnesota Company's jurisdictions (Minnesota, North Dakota, and South Dakota) when the work performed benefits all of the company's customers equally. This is the default allocator that is used for the electric and gas distribution, customer accounting, customer information, sales, and A& G FERC accounts.

This is also the gas utility A&G corporate function default allocator type.

Allocation: Customers Year End Average Minnesota/North Dakota

This allocation type is used to assign costs to both the North Dakota and Minnesota jurisdictions based on customers in the entire North Dakota region. This includes customers in Fargo, Moorhead, Grand Forks, East Grand Forks and Minot service areas. This method is the default allocator for O&M expenses associated with general ledger accounts where the SAP profit center designates support for Minnesota/North Dakota.

Allocation: Customers Year End Average Minnesota/South Dakota

This allocation type is used to assign costs to both the South Dakota and Minnesota jurisdictions based on customers in the entire South Dakota region. This method is the default allocator for O&M expenses associated with general ledger accounts where the SAP profit center designates support for Minnesota/South Dakota.

Allocation: Study Jurisdictional Budget Transmission

This allocation is used for all budgeted plant investment that is determined to be for the direct benefit or in direct support of transmission. It is a historical allocator based on the plant investment that has been direct assigned to jurisdiction based on its state location.

Allocation: Study Jurisdictional Budget Distribution

This allocation is used for all budgeted plant investment that is determined to be for the direct benefit or in direct support of Distribution. It is a historical allocator based on the plant investment that has been direct assigned to jurisdiction based on its state location.

ELECTRIC UTILITY ONLY

Allocation: Energy

Fuel and fuel-related items are assigned to jurisdiction based on the energy allocator because of the direct correlation of customer sales and the level of fuel consumed. These items include all fuel, purchased energy, interchange agreement energy, and variable production expenses.

Allocation: Demand Prod (Coincident Peak)

The 12 coincident peak (CP) demand production allocator is used to assign fixed capacity related expenses, plant, and plant related items to jurisdiction. Other expenses allocated to jurisdiction based on demand include: fixed production expenses, purchased power demand expense, interchange agreement demand charges and regulatory expenses not directly related to one of NSPM's jurisdictions. Also, any A&G costs that are directly in support of production are allocated using this method.

Allocation: Demand Tran (Coincident Peak)

The 12 CP demand transmission allocator is used to assign transmission FERC Accounts in support of NSPM's jurisdictions. Also, any A&G costs that are directly in support of transmission are allocated using this method.

Allocation: Two-Factor Allocator (A&G Only)

Expressed as an equally weighted factor based on electric plant in service and electric O&M expense (excluding A&G); the two-factor allocator is used to allocate electric A&G costs when there is not a direct or cost causative method available. Generally, all corporate electric A&G costs are allocated using this method.

GAS UTILITY ONLY

Allocation: Retail Revenues Cost of Gas Recovery - Demand, Commodity and Purchased Gas Adjustment True-up Study

Retail revenues include components for the recovery of costs associated with product and delivery of product to the service area. Such costs include capacity or entitlement costs, pipeline transportation costs, commodity costs and costs of alternative gas (LPG or LNG) supplied during times of firm peak demand. Regulations provide for the automatic adjustment of billing rates for price changes and the annual true up of the cost of gas incurred. Demand, commodity, and purchased gas adjustment are components of the retail revenues cost of gas recovery study. The portion of total NSPM cost of gas included in retail revenues that the Minnesota jurisdiction represents is also applied to total Minnesota company cost of gas expense accounts to achieve revenue neutrality for revenue requirements consideration.

Allocation: Design Demand Day

Expressed as a percentage, design demand day is the ratio of the Minnesota jurisdiction firm peak demand volume to the total NSPM firm peak demand volume that could occur on the distribution system on a day considered to be the most severe weather conditions that can be experienced.

Allocation: Load Dispatch

Expressed as a percentage, load dispatch is a combination of the Minnesota jurisdiction design demand day and the Minnesota jurisdiction total retail sales and transportation throughput each weighted equally.

Allocation: Limited Firm and Standby Services Study

Expressed as a percentage, limited firm and standby services, in revenues, is the ratio of Minnesota jurisdiction availability charges and volumetric charges to the total NSPM system; in costs, it is the ratio of Minnesota jurisdiction volumetric product costs to the total NSPM program product costs.

Table C

Allocation to Jurisdiction

Sub-Business Unit	Plant Function	Functional Class ID / Description	Location	Functional Use	Utility	Jurisdiction	Allocation Methodology
Selection Criteria *							
Budget							
Production	Production	1 / Electric Steam Production Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Production	2 /Electric Nuclear Production Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Production	3 / Electric Hydro Production Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Production	4 / Electric Other Production Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Production	4 / Electric Other Production Plant-Wind			Electric	MN/ND/SD/WHSL	Electric - Energy
Production	Production	22 / Nuclear Fuel			Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Common & General	24 / Electric Intangible Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Common & General	26 / Common Intangible Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Common & General	29 / Electric General Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Common & General	31 / Common General Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Production	23 / Decommissioning	FERC MN		Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Production	23 / Decommissioning	Minnesota		Electric	MN	Direct Assigned - State of Minnesota
Production	Production	23 / Decommissioning	North Dakota		Electric	ND	Direct Assigned - State of North Dakota
Production	Production	23 / Decommissioning	South Dakota		Electric	SD	Direct Assigned - State of South Dakota
Production	Production	23 / Decommissioning	Wisconsin		Electric	WI	Direct Assigned - Wisconsin
Electric Transmission	Transmission	5 / Electric Transmission Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Tran (Coincident Peak)
Electric Transmission	Transmission	5 / Transmission Direct Assignment	Minnesota	DRCT	Electric	MN	Direct Assigned – State of Minnesota
Electric Distribution	Transmission	5 / Transmission Serving Distribution	Minnesota		Electric	MN	Direct Assigned - State of Minnesota
Electric Distribution	Transmission	5 / Transmission Serving Distribution	North Dakota		Electric	ND	Direct Assigned - State of North Dakota
Electric Distribution	Transmission	5 / Transmission Serving Distribution	South Dakota		Electric	SD	Direct Assigned - State of South Dakota
Production	Transmission	5 / Transmission Generation Step-up		BSLD, PEAK	Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Electric Transmission	Common & General	24 / Electric Intangible Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Tran (Coincident Peak)
Electric Transmission	Common & General	26 / Common Intangible Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Tran (Coincident Peak)

Selection Criteria *							
Sub-Business Unit	**Plant Function**	**Functional Class ID / Description**	**Location**	**Functional Use**	**Utility**	**Jurisdiction**	**Allocation Methodology**
Budget							
Electric Transmission	Common & General	29 / Electric General Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Tran (Coincident Peak)
Electric Transmission	Common & General	31 / Common General Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Tran (Coincident Peak)
Electric Distribution	Distribution	6 / Electric Distribution Plant	Minnesota		Electric	MN	Direct Assigned - State of Minnesota
Electric Distribution	Distribution	6 / Electric Distribution Plant	North Dakota		Electric	ND	Direct Assigned - State of North Dakota
Electric Distribution	Distribution	6 / Electric Distribution Plant	South Dakota		Electric	SD	Direct Assigned - State of South Dakota
Electric Distribution	Distribution	6 / Electric Distribution Plant	Wholesale		Electric	WHSL	Direct Assigned - Wholesale Full Requirements
Production	Distribution	6 / Distribution Generation Step-up		PEAK	Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Electric Transmission	Distribution	6 / Distribution Serving Transmission		TBULK	Electric	MN/ND/SD/WHSL	Electric - Demand Tran (Coincident Peak)
Electric Distribution	Common & General	24 / Electric Intangible Plant			Electric	MN/ND/SD/WHSL	Customer Year End Average - Electric Minnesota Company MN/ND/SD/WHSL
Electric Distribution	Common & General	26 / Common Intangible Plant			Electric	MN/ND/SD/WHSL	Customer Year End Average - Electric Minnesota Company MN/ND/SD/WHSL
Electric Distribution	Common & General	29 / Electric General Plant			Electric	MN/ND/SD/WHSL	Customer Year End Average - Electric Minnesota Company MN/ND/SD/WHSL
Electric Distribution	Common & General	31 / Common General Plant			Electric	MN/ND/SD/WHSL	Customer Year End Average - Electric Minnesota Company MN/ND/SD/WHSL
Gas	Production	7 / Gas Manufactured Production Plant			Gas	MN/ND	Gas - Design Demand Day
Gas	Storage	9 / Gas Underground Storage Plant			Gas	MN/ND	Gas - Design Demand Day
Gas	Transmission	10 / Gas Transmission Plant			Gas	MN	Direct Assigned – State Of Minnesota
Gas	Transmission	10 / Gas Transmission Plant			Gas	ND	Direct Assigned – State of North Dakota
Gas	Distribution	11 / Gas Distribution Plant			Gas	MN	Direct Assigned – State of Minnesota
Gas	Distribution	11 / Gas Distribution Plant			Gas	ND	Direct Assigned – State of North Dakota
Gas	Common & General	25 / Gas Intangible Plant			Gas	MN/ND	Gas - Design Demand Day
Gas	Common & General	26 / Common Intangible Plant			Gas	MN/ND	Gas - Design Demand Day
Gas	Common & General	30 / Gas General Plant			Gas	MN/ND	Gas - Design Demand Day
Gas	Common & General	31 / Common General Plant			Gas	MN/ND	Gas - Design Demand Day

Selection Criteria *							
Sub-Business Unit	**Plant Function**	**Functional Class ID / Description**	**Location**	**Functional Use**	**Utility**	**Jurisdiction**	**Allocation Methodology**
Budget							
Gas	Common & General	25 / Gas Intangible Plant			Gas	MN/ND	Customer Year End Average - Gas Minnesota Company MN/ND
Gas	Common & General	26 / Common Intangible Plant			Gas	MN/ND	Customer Year End Average - Gas Minnesota Company MN/ND
Gas	Common & General	30 / Gas General Plant			Gas	MN/ND	Customer Year End Average - Gas Minnesota Company MN/ND
Gas	Common & General	31 / Common General Plant			Gas	MN/ND	Customer Year End Average - Gas Minnesota Company MN/ND
Gas	Common & General	34 / Gas Other Storage Plant			Gas	MN/ND	Gas - Design Demand Day

* All items under the Selection Criteria must be met before this allocation takes place.

XES Allocation Descriptions, Methods and NSPM Percentages

2022 Test Year Budget

SAP Cost Center	JDE Work Order No.	Cost Center Description	Description of Services Provided	General Allocator/ Cost Causative	Allocation Method	Reasonableness of Allocation Method	NSPM Allocation Percent
200063	110	Executive - Corporate Governance	Executive Corporate Governance includes the labor and non-labor costs for executive corporate management, long-term business strategy development and other programs that ensure the continuity and development of management. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc.	General Allocator	Assets/Revenue/No. of Employees	Executive - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore, the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative effect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative effect on the consolidated business. No. of Employees is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	38.9021%
200064	115	Shareholder - Corporate Governance	Shareholder - Corporate Governance includes the labor and non-labor costs for serving as liaison between Xcel Energy BOD and the shareholders, manages employee/executive stock award matters, liaison between Xcel Energy and the proxy advisory group, monitoring stock ownership patterns, planning shareholder meetings, coordinating the transfer agent and shareholder record keeping functions. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc.	General Allocator	Assets/Revenue/No. of Employees	Shareholder - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore, the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative effect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative effect on the consolidated business. No. of Employees is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	38.9021%
200065	116	Investor Relations - Corporate Governance	Investor Relations - Corporate Governance includes the labor and non-labor costs for communications to investors and the financial community, providing management with feedback from investors, assisting in the communication to investors of debt and equity securities issuances, assists in the development of presentations for Board of Directors, develops and delivers Xcel Energy's credit story to credit rating agencies, develops and presents Xcel Energy's investment story to investors, reviews all public financial documents for accuracy and completeness and distributes all financial releases. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc.	General Allocator	Assets/Revenue/No. of Employees	Investor Relations - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore, the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative effect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative effect on the consolidated business. No. of Employees is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	38.9021%
200066	121	Accounting, Reporting & Tax - Corporate Governance	Accounting, Reporting & Tax - Corporate Governance includes the labor and non-labor costs associated with preparing and filing consolidated reporting and financial statements, preparing consolidated budgets, completing the consolidation process, maintaining the books and records of Xcel Energy Inc. and Service Company, composing the corporate-wide regulatory accounting policy and compliance, Sarbanes-Oxley (SOX) documentation and compliance, and Chief Financial Officer activities related to the Audit Committee. Provides financial leadership to Xcel Energy and provides policies, controls, and leadership to the Financial Operations business area. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc.	General Allocator	Assets/Revenue/No. of Employees	Accounting, Reporting & Tax - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore, the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative effect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative effect on the consolidated business. No. of Employees is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	38.9021%
200067	131	Audit Services - Corporate Governance	Audit Services corporate governance includes the labor and non-labor costs associated with the financial operations and information system audits of the holding company and service company; evaluating and improving risk management, corporate internal control guidelines and procedures; ethical conduct and the implementation of best practices, reviewing financial reporting requirements and controls under Sarbanes-Oxley legislative requirements, auditing of consolidated financial statements and activities related to the Audit Committee, performing audits and reviews for compliance with regulatory and legal requirements an contracts with vendors and other parties, providing consulting services to management for operational and process improvement reviews, assistance in internal investigations of fraud, administering the corporate compliance hotline, conflict of interest investigations, or other potential violations of the Xcel Energy Code of Conduct. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc.	General Allocator	Assets/Revenue/No. of Employees	Audit Services - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore, the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative effect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative effect on the consolidated business. No. of Employees is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	38.9021%

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SAP Cost Center	JDE Work Order No.	Cost Center Description	Description of Services Provided	General Allocator/ Cost Causative	Allocation Method	Reasonableness of Allocation Method	NSPM Allocation Percent
200068	141	Corporate Finance, Treasury & Cash Management - Corporate Governance	Corporate Finance, Treasury & Cash Management - Corporate Governance includes the labor and non-labor costs related to equity and debt securities issuance, relationships with financial institutions, cash management, investing activities and monitoring the capital markets, holding company commercial paper transactions, compliance with debt covenants, corporate-wide protection of assets from catastrophic loss using risk financing mechanisms including captive risk retention and design and negotiation of insurance contracts with commercial and industry mutual underwriters (Service Company portion of Auto Liability, Cyber, and various other insurance policies), supervising the asset management firms for the Pension Fund and 401k benefits. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc.	General Allocator	Assets/Revenue/No. of Employees	Corporate Finance, Treasury & Cash Management - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore, the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative effect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative effect on the consolidated business. No. of Employees is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	38.9021%
200069	143	Risk Management - Corporate Governance	Risk Management Corporate Governance includes the labor and non-labor costs of providing administration of the Transaction Review Committee which handles contract and deal approvals for Commercial Operations, Resource Planning and Energy Supply, provides analysis associated with key risks facing Xcel Energy Inc., negotiates and manages required security (e.g., bank letters of credit, bonds and guarantees among others); reviews and approves all documents requiring Contracts area sign-off. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc.	General Allocator	Assets/Revenue/No. of Employees	Risk Management - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore, the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative effect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative effect on the consolidated business. No. of Employees is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	38.9021%
200070	161	Corporate Strategy & Business Development - Corporate Governance	Corporate Strategy & Business Development - Corporate Governance includes the labor and non-labor costs associated with providing leadership for the implementation of company-wide business strategies and plans; portfolio management including the evaluation of potential opportunities for mergers, acquisitions and divestitures; providing financial, analytical and reporting support; researching and providing business intelligence information. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc.	General Allocator	Assets/Revenue/No. of Employees	Corporate Strategy & Business Development - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore, the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative effect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative effect on the consolidated business. No. of Employees is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	38.9021%
200071	171	Legal - Corporate Governance	Legal - Corporate Governance includes the labor and non-labor costs for anticipating and fulfilling the legal needs of Xcel Energy, its Board of Directors, officers, legal entities, business areas and corporate operations to protect the company's assets and to minimize potential liability. Provides services related to labor and employment law pertaining to Service Company employees, litigation, contracts, rates and regulation, environmental matters and other legal matters. Supports Xcel Energy and its subsidiaries in fulfilling corporate and business area strategies ranging from maintaining/improving regulatory relationships to continued leadership on environmental issues. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc.	General Allocator	Assets/Revenue/No. of Employees	Legal - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore, the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative effect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative effect on the consolidated business. No. of Employees is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	38.9021%
200072	180	Communications - Corporate Governance	Communications - Corporate Governance includes the labor and non-labor costs to assist and ensure Executive Management, Investor Relations and others communicate appropriately with shareholders, the public, and other key stakeholder audiences. Key projects include: development and production of the annual report and other communications to investors; speeches, videos, and major presentations delivered by top executives; and speeches, displays, video and presentations for the company's annual meeting of shareholders. Media Relations contributes to building Xcel Energy's reputation by developing media and public relations strategies for major company initiatives and issues; responding to news media inquiries; working pro-actively with the media to forward story ideas and information about company events, policies and actions, and providing media training for company spokespersons. Media Relations also plays a key role in crisis communications and emergency preparedness efforts. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc.	General Allocator	Assets/Revenue/No. of Employees	Communications - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore, the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative effect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative effect on the consolidated business. No. of Employees is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	38.9021%
200073	189	Human Resources - Corporate Governance	Human Resources - Corporate Governance includes the labor and non-labor costs for executive officers' and Service Company employees' compensation plans, corporate HR policies, executive policy benefit plans, payroll services for Service Company and the employees' handbook. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc.	General Allocator	Assets/Revenue/No. of Employees	Human Resources - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore, the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative effect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative effect on the consolidated business. No. of Employees is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	38.9021%

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SAP Cost Center	JDE Work Order No.	Cost Center Description	Description of Services Provided	General Allocator/ Cost Causative	Allocation Method	Reasonableness of Allocation Method	NSPM Allocation Percent
200074	529; 549; 551; 561	Corporate Systems – Corporate Governance	Corporate Systems – Corporate Governance includes the labor and non-labor costs for enterprise-wide corporate systems.	General Allocator	Assets/Revenue/No. of Employees	Corporate Systems - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore, the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative effect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative effect on the consolidated business. No. of Employees is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	38.9021%
200075	114	Board of Directors - Corporate Governance	Board of Directors - Corporate Governance includes the labor and non-labor costs related to the Board of Directors (BOD). BOD costs may include Directors fees, retirement expenses and replacement fees; Board/Committee meetings and BOD related consulting. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc.	General Allocator	Assets/Revenue/No. of Employees	Board of Directors - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore, the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative effect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative effect on the consolidated business. No. of Employees is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	38.9021%
200076	182	Xcel Foundation	Xcel Foundation services includes the labor and non-labor costs associated with the management and administration of the Xcel Energy Foundation.	General Allocator	Assets/Revenue/No. of Employees	Xcel Foundation services that could not be directly charged to a specific legal entity and are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	38.9671%
200077	184	Branding	Branding services includes the labor and non-labor costs for brand advertising and management of community affairs programs such as employee volunteerism, educational programs and community events, the company's investment in major sponsorships such as the Xcel Energy Center as well as ensuring that such sponsorships and related activities support the company's brand, mission and values.	General Allocator	Assets/Revenue/No. of Employees	Branding services that could not be directly charged to a specific legal entity and are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	38.9671%
200078	410	Governmental Affairs	Governmental Affairs includes the labor and non-labor costs associated with the interpretation of laws regulations and environmental policy to ensure compliance and cost effectiveness for Xcel Energy customers and stockholders Internal legislative policy development and issues management, appraise management and internal customers of political and policy trends and developments, develop and maintain relationships with regulatory officials and staff.	General Allocator	Assets/Revenue/No. of Employees	Governmental Affairs services that could not be directly charged to a specific legal entity and are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	38.9904%
200079	409	Federal Lobbying	Federal Lobbying services includes the labor and non-labor costs for federal and state lobbying activities and the federal Political Action Committee (PAC).	General Allocator	Assets/Revenue/No. of Employees	Federal Lobbying services that could not be directly charged to a specific legal entity and are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are provided to a subset of companies based on who benefits from the services. These costs are recorded in FERC 426.4.	38.9904%
200080	135	Capital Asset Accounting	Capital Asset Accounting includes the labor and non-labor costs associated with operating and non-operating company capital asset accounting, budgeting, regulatory reporting, business area support for utility areas, and operating company budgeting support.	General Allocator	Assets/Revenue/No. of Employees	Capital Asset Accounting services that could not be directly charged to a specific legal entity and are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	44.1421%
200081	120	Accounting, Reporting & Taxes	Accounting, Reporting & Taxes services includes the labor and non-labor costs for preparation of operating and non-operating financial statements, tax returns and reporting, performing accounting for the employee benefit plans, ensuring compliance with applicable laws and regulations of the operating and non-operating companies; composing the corporate-wide regulatory accounting policy, and coordinating the budgeting process with the operating and non-operating companies.	General Allocator	Assets/Revenue/No. of Employees	Accounting Reporting & Taxes services that could not be directly charged to a specific legal entity and are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	44.2178%
200082	130	Audit Services	Audit Services includes the labor and non-labor costs for auditing operating and non-operating companies, evaluating and improving risk management, ethical conduct and the implementation of best practices for operating and non-operating companies, conducting financial operations and information system audits, performing audits and reviews for compliance with regulatory and legal requirements and contracts with vendors and other parties; establishing and reviewing internal controls for operating and non-operating companies, establishing and reviewing SOX compliance requirements/control testing and evaluating contract risks for the operating and non-operating companies.	General Allocator	Assets/Revenue/No. of Employees	Audit Services that could not be directly charged to a specific legal entity and are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	44.2178%

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SAP Cost Center	JDE Work Order No.	Cost Center Description	Description of Services Provided	General Allocator/ Cost Causative	Allocation Method	Reasonableness of Allocation Method	NSPM Allocation Percent
200083	140	Corporate Finance, Treasury & Cash Management	Corporate Finance, Treasury & Cash Management services includes the labor and non-labor costs related to equity and debt securities issuance, cash management, relationships with financial institutions, compliance with debt covenants, Service Company portion of General and Excess liability insurance, and management of the Pension Fund and 401k benefits for operating companies.	General Allocator	Assets/Revenue/No. of Employees	Corporate Finance, Treasury & Cash Management services that could not be directly charged to a specific legal entity and are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	44.2178%
200084	142	Risk Management	Risk Management develops and negotiates security agreements with counterparties; reviews high-risk vendor creditworthiness for the Environmental Services group; supports wind generation, solar carbon offsets, emission allowances, bundled energy and RECs, biomass and other renewable energy purchase agreements; participates in industry contracts working groups; representing Xcel Energy operating utilities; performs production cost modeling and analysis for corporate budgeting; analyzing value and risks of structured purchases and generation system modifications; performs long range system modeling to evaluate large capacity acquisition alternatives; provides central coordination of annual capital funding process for Distribution and maintains and administers the Risk Registry database, evaluates and prioritizes specific risk mitigations for Distribution assets; develops strategies for Distribution infrastructure including building and implementing stochastic models for asset life-cycle analysis and other ad hoc asset specific requests; creates retail and system load and energy forecasts providing regular updates to senior management and analyses of key drivers; provides data support and analyses for financial disclosures; and provides analyses and reporting of current sales and peak demand levels relative to forecasts.	General Allocator	Assets/Revenue/No. of Employees	Risk Management services that could not be directly charged to a specific legal entity and are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	44.2178%
200086	170	Legal & Claims Services	Legal & Claims Services includes the labor and non-labor costs for operating and non-operating legal services related to: labor and employment law, litigation, rates and regulation, environmental matters, real estate, contracts, and claims services related to casualty, public, and company claims.	General Allocator	Assets/Revenue/No. of Employees	Legal & Claims Services that could not be directly charged to a specific legal entity and are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	44.2178%
200087	123	Accounting, Reporting & Tax - Regulated	Accounting, Reporting & Tax - Regulated includes the labor and non-labor costs associated with operating company revenue accounting, budgeting, regulatory reporting, sales and use taxes, business area support for utility areas, operating company budgeting support, and capital asset accounting.	General Allocator	Assets/Revenue/No. of Employees	Accounting, Reporting & Tax - Regulated services that could not be directly charged to a specific legal entity and are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to regulated companies based on who benefits from the services.	44.2290%
200088	127; 133	Accounting, Reporting, Tax & Audit Services - Regulated Electric	Accounting, Reporting, Tax & Audit Services - Regulated Electric includes the labor and non-labor costs associated specifically with operating company electric utility revenue accounting, budgeting, regulatory reporting, sales and use taxes, business area support for utility areas, operating company budgeting support, capital asset accounting auditing operating companies , evaluating and improving risk management, ethical conduct and the implementation of best practices for operating companies electric utility, conducting financial operations and information system audits, performing audits and reviews for compliance with regulatory and legal requirements and contracts with vendors and other parties; establishing and reviewing internal controls for operating companies electric utility, establishing and reviewing SOX compliance requirements/control testing and evaluating contract risks for the operating companies electric utility. Additionally, costs for electric association dues including Edision Electric Institute (EEI).	General Allocator	Assets/Revenue/No. of Employees	Accounting, Reporting, Tax & Audit Services - Regulated Electric services that could not be directly charged to a specific legal entity and are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to regulated companies with electric operations who benefits from the services.	44.2290%
200089	132	Audit Services - OpCo's & TransCo's	Audit Services - OpCo's & TransCo's includes the labor and non-labor costs for auditing operating companies, evaluating and improving risk management, ethical conduct and the implementation of best practices for operating companies, conducting financial operations and information system audits, performing audits and reviews for compliance with regulatory and legal requirements and contracts with vendors and other parties; establishing and reviewing internal controls for operating companies, establishing and reviewing SOX compliance requirements/control testing and evaluating contract risks for the operating companies.	General Allocator	Assets/Revenue/No. of Employees	Audit Services - OpCo's & TransCo's services that could not be directly charged to a specific legal entity and are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies and Transmission-only companies who benefit from the services.	44.2290%
200090	146	Risk Management - OpCo's & TransCo's	Risk Management - OpCo's & TransCo's includes the labor and non-labor costs of oversight and administrative of operating company risk management work, working with counterparties to establish enabling agreements with operating companies, risk management reports including all operating companies (such as CDAD - Contract Development, Approval & Delegation or TRC- Transaction Review Committee Reporting).	General Allocator	Assets/Revenue/No. of Employees	Risk Management - OpCo's & TransCo's services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies and Transmission-only companies who benefit from the services.	44.2290%

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200091	147	Captive Insurance	Captive Insurance - The Property Loss Control Engineers services includes the labor and non-labor costs for each primary Operating Company(s) as well as all of Energy Supply Services. Having an expertise in an area, they lend support to each other and members of Energy Supply, and the Utilities Group, throughout the corporation. Fire Protection, Transformer Maintenance, Turbine Characteristics, Policies and Procedures are some of the areas in which expertise has been developed. This expertise is then shared on a regular basis to the benefit of all OpCo's and it is further shared at periodic Engineering meetings hosted by Hazard Insurance, which bring together Engineers from the OpCo's, the Property Loss Control Engineers and Insurance Company representatives to promote Loss Control.	General Allocator	Assets/Revenue/No. of Employees	Captive Insurance services that could not be directly charged to a specific legal entity and are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies who benefit from the services.	44.2290%
200092	162	Corporate Strategy & Business Development	Corporate Strategy & Business Development services include the labor and non-labor costs associated with providing leadership for the implementation of company-wide business strategies and plans; portfolio management including the evaluation of potential opportunities for mergers, acquisitions and divestitures; providing financial, analytical and reporting support; researching and providing business intelligence information.	General Allocator	Assets/Revenue/No. of Employees	Corporate Strategy & Business Development services that could not be directly charged to a specific legal entity and are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies who benefit from the services.	44.2290%
200093	174	Legal - OpCo's & TransCo's	Legal - OpCo's & TransCo's services include the labor and non-labor costs for operating companies legal services related to: labor and employment law, litigation, rates and regulation, environmental matters, real estate and contracts.	General Allocator	Assets/Revenue/No. of Employees	Legal - OpCo's & TransCo's services that could not be directly charged to a specific legal entity and are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies and Transmission-only companies who benefit from the services.	44.2290%
200094	416	Supply Chain	Supply Chain includes the labor and non-labor costs for operating companies diversity program expenses as well as various dues for specific sponsored agencies (Chamber of Commerce, social service dues, etc.)	General Allocator	Assets/Revenue/No. of Employees	Supply chain services that could not be directly charged to a specific legal entity and are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies who benefit from the services.	44.2290%
200095	430	Energy Supply Asset Management	Energy Supply Asset Management services includes the labor and non-labor costs of providing management support to the Energy Supply organization, maximizing business value of the Energy Supply information systems, developing the business plan, optimizing plant inventory, and leading the development of asset management strategy and implementation.	General Allocator	Assets/Revenue/No. of Employees	Energy Supply Asset Management services that could not be directly charged to a specific legal entity and are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	44.2290%
200096	431	Energy Markets - Business Services	Energy Markets Business Services includes the labor and non-labor costs for financial analysis, budgeting and administrative support, managerial reporting and business planning and process initiatives, independent daily forward valuation and risk measurement of commodity transactions and system fuel and purchase power requirements to meet system loads, as well as proprietary or trading transactions; creates retail system load and energy forecasts providing regular updates to senior management and analyses of key drivers, reviews and provides comments to dealmakers on non-standard agreements and associated confirmation agreements in the areas of coal supply, gas supply, wood fuel, rail, trucking, structured power purchases and nuclear/uranium concentrates and services; provides analyses for electric/gas hedge studies and sensitivities; creates load management forecast, jurisdictional peak demand forecasts, and cost of service studies for energy trading and marketing.	General Allocator	Assets/Revenue/No. of Employees	Energy Markets - Business Services that could not be directly charged to a specific legal entity and are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	44.2290%
200097	533; 535; 539; 542	Accounting and Finance Software Applications Maintenance	Accounting and Finance Software Applications Maintenance services include the labor and non-labor operating costs for the application development and maintenance of the software applications used for accounting and finance business functions.	General Allocator	Assets/Revenue/No. of Employees	Accounting and Finance Software Applications Maintenance - The Business Systems expenses related to maintenance of this system that could not be directly charged to a specific legal entity and are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	44.2290%
200098	468	Electric Transmission FERC 566	Electric Transmission FERC 566 services include Transmission electric labor and non-labor costs associated with accounting, budgeting, regulatory reporting, and capital asset accounting.	General Allocator	Assets/Revenue/No. of Employees	Electric Transmission FERC 566 charges that cannot be directly charged to a specific legal entity and are corporate in nature. The three-factor formula is used because these charges are comprised of a broad spectrum of activities and no measurable method of cost causative allocation was found.	44.2290%
200099	469	Electric Distribution FERC 588	Electric Distribution FERC 588 services include electric Distribution labor and non-labor costs associated with accounting, budgeting, regulatory reporting, and capital asset accounting.	General Allocator	Assets/Revenue/No. of Employees	Electric Distribution FERC 588 charges that cannot be directly charged to a specific legal entity and are corporate in nature. The three-factor formula is used because these charges are comprised of a broad spectrum of activities and no measurable method of cost causative allocation was found.	44.2290%

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SAP Cost Center	JDE Work Order No.	Cost Center Description	Description of Services Provided	General Allocator/ Cost Causative	Allocation Method	Reasonableness of Allocation Method	NSPM Allocation Percent
200100	134	Accounting, Reporting, Tax & Audit Services – Regulated Gas	Accounting, Reporting, Tax & Audit Services – Regulated Gas includes the labor and non-labor costs associated specifically with gas utility revenue accounting, budgeting, regulatory reporting, sales and use taxes, business area support for utility areas, capital asset accounting, auditing, evaluating and improving risk management, ethical conduct and the implementation of best practices for operating companies gas utility, conducting financial operations and information system audits, performing audits and reviews for compliance with regulatory and legal requirements and contracts with vendors and other parties; establishing and reviewing internal controls for operating companies gas utility, establishing and reviewing SOX compliance requirements/control testing and evaluating contract risks for the operating companies gas utility. Additionally, costs for gas association dues including American Gas Association (AGA).	General Allocator	Assets/Revenue/No. of Employees	Accounting, Reporting, Tax & Audit Services – Regulated Gas services that could not be directly charged to a specific legal entity and are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies gas utility who benefit from the services.	52.1537%
200101	164	Legal Gas	Legal Gas services include the labor and non-labor costs for operating companies gas utility legal services related to: labor and employment law, litigation, rates and regulation, environmental matters, real estate and contracts. This is primarily used by the General Counsel area.	General Allocator	Assets/Revenue/No. of Employees	Legal Gas services that could not be directly charged to a specific legal entity and are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies who benefit from the services.	52.1537%
200102	470	Gas Distribution FERC 880	Gas Distribution FERC 880 services include gas Distribution labor and non-labor costs associated with accounting, budgeting, regulatory reporting, and capital asset accounting.	General Allocator	Assets/Revenue/No. of Employees	Gas Distribution FERC 880 charges that cannot be directly charged to a specific legal entity and are corporate in nature. The three-factor formula is used because these charges are comprised of a broad spectrum of activities and no measurable method of cost causative allocation was found.	52.1537%
200105	125	Accounting & Reporting - NSPM & NSPW	Accounting & Reporting - NSPM & NSPW includes the labor and non-labor costs associated with NSPM & NSPW accounting, budgeting, regulatory reporting, sales and use taxes, business area support for utility areas, operating company budgeting support, and capital asset accounting.	General Allocator	Assets/Revenue/No. of Employees	Accounting & Reporting - NSPM & NSPW services that could not be directly charged to a specific legal entity and are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to NSPM & NSPW who benefit from the services.	86.9558%
200106	126	Accounting & Reporting Electric - NSPM & NSPW	Accounting & Reporting Electric - NSPM & NSPW includes the labor and non-labor costs associated with NSPM & NSPW accounting, budgeting, regulatory reporting, sales and use taxes, business area support for utility areas, operating company budgeting support, and capital asset accounting specific to the electric utility.	General Allocator	Assets/Revenue/No. of Employees	Accounting & Reporting Electric - NSPM & NSPW services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to NSPM & NSPW electric utility who benefit from the services.	86.9558%
200107	172	Legal - NSPM & NSPW	Legal - NSPM & NSPW services include the labor and non-labor costs for legal services related to: labor and employment law, litigation, rates and regulation, environmental matters, real estate and contracts specific to NSPM & NSPW. This is primarily used by the General Counsel area.	General Allocator	Assets/Revenue/No. of Employees	Legal - NSPM & NSPW services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to NSPM & NSPW who benefit from the services.	86.9558%
200108	N/A	Advanced Metering Infrastructure (AMI)	Advanced Metering Infrastructure (AMI) includes the labor and non-labor costs associated with AMI.	Cost Causative	No. of AMI Enabled Meters	Advanced Metering Infrastructure (AMI) using No. of AMI Enabled Meters to allocate costs is reasonable because there is a cost causative relationship with the companies with AMI enabled meters.	56.2262%
200111	544	Enterprise Application Integration (EAI)	Enterprise Application Integration (EAI) includes the labor and non-labor costs associated with the management of information systems infrastructure and working with IT Project Managers to ensure that new systems are positioned to function as successfully as possible in terms of overall performance and communication with other systems.	Cost Causative	Average of a Select Set of Software Allocators	Enterprise Application Integration (EAI) using average of selected software systems to allocate costs is reasonable because EAI is primarily the server costs supporting the selected software applications and benefits the companies using the software applications.	39.0533%
200112	562	Mainframe Charges	Mainframe Charges include labor and non-labor costs related to mainframe expenses for development, maintenance, and licensing. The Mainframe is comprised of three applications: Time, Gas Management System, and Monitoring Device Management System applications. This is used primarily by the Business Systems Organization.	Cost Causative	Average of a Select Set of Software Allocators	Mainframe Charges expenses cannot be directly charged to a specific legal entity as the system is used by multiple entities. Using an average of selected software systems to allocate costs is reasonable because Mainframe primarily supports these selected software systems.	28.0236%
200115	514	Miscellaneous Applications	Miscellaneous Applications includes the labor and non-labor costs associated with the management of information systems infrastructure and working with IT project managers to ensure that new systems are positioned to function as successfully as possible in terms of overall performance and communication with other systems.	Cost Causative	Average of All Software Percentages	Miscellaneous Applications using average of all software systems to allocate costs is reasonable because Miscellaneous Applications is primarily the server costs supporting the software applications and benefits the companies using the software applications.	35.5212%
200116	441	Distribution Electric Supervision & Engineering (S&E) FERC 580	Distribution Electric Supervision & Engineering (S&E) FERC 580 services includes the labor and expenses incurred in the general supervision and direction of the operation of the electric distribution system.	Cost Causative	Electric Distribution Plant	Distribution Electric Supervision & Engineering (S&E) FERC 580 using the electric distribution plant to allocate the costs is reasonable because there is a cost causative relationship with the operations supported by electric distribution.	34.8209%
200117	453	Distribution Electric Metering FERC 586	Distribution Electric Metering FERC 586 services include labor, materials used, and expenses incurred in the operation of customer meters and associated equipment (e.g. electric distribution meters standards and development, meter purchases, etc.	Cost Causative	Electric Distribution Plant	Distribution Electric Metering FERC 586 using electric distribution plant to allocate meter costs is reasonable because there is a cost causative relationship with the electric distribution plant and meter operations supported by electric distribution.	34.8209%
200118	527	Distribution Electric Load Dispatching/EMS FERC 581	Distribution Electric Load Dispatching/EMS FERC 581 services include labor, materials used, and expenses incurred in load dispatching operations pertaining to the distribution of electricity. This includes Energy Management Systems (EMS) which provides supervisory control and data acquisition (SCADA) of substation devices through Remote Terminal Units (RTU's).	Cost Causative	Electric Distribution Plant	Distribution Electric Load Dispatching/EMS FERC 581 using electric distribution plant to allocate costs is reasonable because there is a cost causative relationship with the operations supported by load dispatching/EMS-distribution.	34.8209%

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SAP Cost Center	JDE Work Order No.	Cost Center Description	Description of Services Provided	General Allocator/ Cost Causative	Allocation Method	Reasonableness of Allocation Method	NSPM Allocation Percent
200119	506; 507; 559	Distribution Electric & Gas Miscellaneous FERC 588 & 880	Distribution Electric & Gas Miscellaneous FERC 588 & 880 services include labor, materials used, and expenses incurred in distribution system operation not provided for elsewhere. This includes software system labor and non-labor costs for the maintenance that support the electric and gas distribution to our customers as well as non-capital engineering & supervision costs.	Cost Causative	Electric Distribution Plant/ Gas Distribution Plant	Distribution Electric & Gas Miscellaneous FERC 588 & 880 using a ratio of electric distribution plant/gas distribution plant to allocate costs is reasonable because there is a cost causative relationship between the work performed by operations and distribution plant.	32.6107%
200120		Distribution & Transmission Gas Miscellaneous FERC 859 & 880	Distribution & Transmission Gas Miscellaneous FERC 859 & 880 include the cost of labor, materials used, and expenses incurred in providing Gas Emergency Response (GER) activities for the gas distribution and transmission systems as well as other activities related to the gas distribution and transmission systems. Additionally, costs include the labor and non-labor costs for the application development and maintenance of the GER system.	Cost Causative	Gas Distribution Plant/Gas Transmission Plant	Distribution & Transmission Gas Miscellaneous FERC 588 & 880 using a ratio of gas distribution plant/gas transmission plant to allocate costs is reasonable because the costs are directly related to miscellaneous activities, including Gas Emergency Response work for the gas distribution and gas transmission systems.	23.2473%
200121	474	Distribution Electric & Gas and Transmission Gas Miscellaneous FERC 588, 880, & 859	Distribution Electric & Gas and Transmission Gas Miscellaneous FERC 588, 880, & 859 services include gas distribution, gas transmission, and electric distribution labor and non-labor costs associated with accounting, budgeting, and regulatory reporting.	Cost Causative	Electric Distribution Plant/ Gas Transmission Plant/ Gas Distribution Plant	Distribution Electric & Gas and Transmission Gas Miscellaneous FERC 588, 880, & 859 charges that cannot be directly charged to a specific business unit and are corporate in nature. Using a ratio of electric distribution plant/gas transmission plant/gas distribution plant to allocate Utility Group costs is reasonable because there is a cost causative relationship with operations supported by Utilities Group.	30.9774%
200122	442	Transmission Electric Supervision & Engineering (S&E) FERC 560	Transmission Electric Supervision & Engineering (S&E) FERC 560 services include labor and expenses incurred in the general supervision and direction of the operation of the electric transmission system as a whole.	Cost Causative	Electric Transmission Plant	Transmission Electric Supervision & Engineering (S&E) FERC 560 using electric transmission plant to allocate costs is reasonable because there is a cost causative relationship with the operations supported by transmission electric.	32.7858%
200123	451	Transmission Electric Reliability, Planning, & Standards Development FERC 561.5	Transmission Electric FERC 561.5 services include labor, materials used, and expenses incurred for the system planning of the interconnected bulk electric transmission systems within a planning authority area. Activities include transmission reliability, planning and standards development related to transmission assets and reliability needs and transmission customers' requirements and requests (e.g. developing and maintaining transmission system models, applying methodologies and tools for analysis and simulation of systems, notification of any planned transmission changes and impacts, etc.).	Cost Causative	Electric Transmission Plant	Transmission Electric Reliability, Planning, & Standards Development FERC 561.5 using electric transmission plant to allocate costs is reasonable because there is a cost causative relationship with the operations supported by transmission electric.	32.7858%
200124	526	Transmission Electric Load Dispatch-Monitor and Operate Transmission System FERC 561.2	Transmission Electric Load Dispatch-Monitor and Operate Transmission System FERC 561.2 services include labor, materials used, and expenses incurred to monitor, assess and operate the power system and individual transmission facilities in real-time to maintain safe and reliable operation of the transmission system. This also includes the expense incurred to manage transmission facilities to maintain system reliability and to monitor the real-time flows and direct actions according to regional plans and tariffs as necessary.	Cost Causative	Electric Transmission Plant	Transmission Electric Load Dispatch-Monitor and Operate Transmission System FERC 561.2 using electric transmission plant to allocate costs is reasonable because there is a direct causal relationship with the operations supported by EMS-transmission.	32.7858%
200125	449	Transmission Electric Supervision & Engineering (S&E) NSPM & NSPW FERC 560	Transmission Electric Supervision & Engineering (S&E) NSPM & NSPW FERC 560 services include labor and expenses incurred in the general supervision and direction of the operation of the electric transmission system as a whole. This allocation is used when NSPM and NSPW are the only jurisdictions benefiting from the services.	Cost Causative	Electric Transmission Plant	Transmission Electric Supervision & Engineering (S&E) NSPM & NSPW FERC 560 using electric transmission plant to allocate costs is reasonable because there is a direct causal relationship with the operations supported by transmission electric.	73.5882%
200126	423; 440; 525	Utilities Group Administrative & General (A&G) FERC 921	Utilities Group Administrative & General (A&G) FERC 921 services includes the labor and non-labor costs for utilities group leadership, management and support services for the Distribution, Transmission, transportation and supply chain areas.	Cost Causative	Electric Transmission Plant/ Electric Distribution Plant/ Gas Transmission Plant/Gas Distribution Plant	Utilities Group Administrative & General (A&G) FERC 921 using delivery gross plant to allocate costs is reasonable because these costs are directly related to the electric and gas delivery systems.	31.6613%
200127	443	Distribution Gas Supervision & Engineering (S&E) FERC 870	Distribution Gas Supervision & Engineering (S&E) FERC 870 services include labor and expenses incurred in the general supervision and direction of gas distribution system operations.	Cost Causative	Gas Distribution Plant	Distribution Gas Supervision & Engineering (S&E) FERC 870 using gas distribution plant to allocate costs is reasonable because there is a cost causative relationship with the operations supported by distribution gas.	27.0124%
200128	445	Distribution Gas Miscellaneous FERC 880	Distribution Gas Miscellaneous FERC 880 services include the cost of distribution maps and records, distribution office expenses, and the cost of miscellaneous labor and materials used, and expenses incurred in gas distribution systems. Additionally, the labor and non-labor costs for non-capital engineering and supervision.	Cost Causative	Gas Distribution Plant	Distribution Gas Miscellaneous FERC 880 using gas distribution plant to allocate costs is reasonable because there is a cost causative relationship with the operations supported by Distribution Gas.	27.0124%
200129	454	Distribution Gas Meters and House Regulators FERC 878	Distribution Gas Meters and House Regulators FERC 878 services include the cost of labor, materials used and expenses incurred in connection with removing, resetting, changing, testing, and servicing customer meters and house regulators.	Cost Causative	Gas Distribution Plant	Distribution Gas Meters and House Regulators FERC 878 using gas distribution plant to allocate meter costs is reasonable because there is a cost causative relationship with the gas distribution plant and meter operations supported by gas distribution.	27.0124%
200130	444	Transmission Gas Supervision & Engineering (S&E) FERC 850	Transmission Gas Supervision & Engineering (S&E) FERC 850 services include the cost of labor and expenses incurred in the general supervision and direction of the operation of transmission facilities.	Cost Causative	Gas Transmission Plant	Transmission Gas Supervision & Engineering (S&E) FERC 850 using gas transmission plant to allocate costs is reasonable because there is a cost causative relationship with the operations supported by transmission gas.	8.7347%
200131	531	Distribution & Transmission Gas System Control and Load Dispatching FERC 851 & 871	Distribution & Transmission Gas System Control and Load Dispatching FERC 851 & 871 include the cost of labor, materials used, and expenses incurred in dispatching and controlling the supply and flow of gas through the gas distribution and transmission systems. Additionally, costs include the labor and non-labor costs for the application development and maintenance of the Gas SCADA system.	Cost Causative	Gas Transmission Plant/ Gas Distribution Plant	Distribution & Transmission Gas System Control and Load Dispatching FERC 851 & 871 using a ratio of gas transmission plant/gas distribution plant to allocate costs is reasonable because the costs are directly related to the monitoring of gas distribution and transmission.	23.2473%

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SAP Cost Center	JDE Work Order No.	Cost Center Description	Description of Services Provided	General Allocator/ Cost Causative	Allocation Method	Reasonableness of Allocation Method	NSPM Allocation Percent
200132	413	Payment & Reporting	Payment & Reporting services includes the labor and non-labor costs associated with processing payments to vendors, providing audit research and reconciliation support for Accounts Payable transactions, preparing statistical and 1099 reporting, and administering the purchase card programs.	Cost Causative	Invoice Transactions	Payment & Reporting using invoice transactions to allocate costs is reasonable because the costs are directly related to invoices processed.	26.4351%
200133	128	Proprietary Trading - Back Office	Proprietary Trading - Back Office includes the labor and non-labor costs associated with the accounting support and vice president oversight of proprietary trading activities. This allocator should be primarily used by Accounting and Finance, or others providing Administrative & General (A&G) activities when the trading deal doesn't involve Xcel Energy Utility generating resources, which is also considered non-asset-based trading activity.	Cost Causative	Joint Operating Agreement Peak Hour Megawatt Load Ratio	Proprietary Trading - Back Office uses the Joint Operating Agreement Peak Hour Megawatt Load Ratio for cost allocations as it is required for the Proprietary Trading services under the JOA.	36.5625%
200134	144	Proprietary Trading - Front/Mid Office FERC 557	Proprietary Trading - Front/Mid Office FERC 557 includes the labor and non-labor costs associated with proprietary trading activities which are short term transactions undertaken in the wholesale electric markets where electricity is purchased for the purpose of selling it. Also included are supporting activities: evaluating the credit worthiness of counterparties, reviewing contracts to ensure that regulations are being complied with, evaluating profitability and appropriateness of trades to ensure they are in the best interest of shareholders and rate payers, and ensuring that trades identified as proprietary appropriately fall into that category.	General Allocator	Joint Operating Agreement Peak Hour Megawatt Load Ratio	Proprietary Trading - Front/Mid Office FERC 557 uses the Joint Operating Agreement Peak Hour Megawatt Load Ratio for cost allocations as it is required for the Proprietary Trading services under the JOA.	43.8925%
200135	414	Energy Supply Business Resources	Energy Supply Business Resources services includes the labor and non-labor costs of performance analysis, specialists and analytical services provided to the operating companies' generation facilities.	Cost Causative	MWH Generation	Energy Supply Business Resources using MWH generation to allocate costs is reasonable because the costs are directly related to the support of electric generation facilities.	35.3947%
200136	415	Energy Markets - Fuel	Energy Markets - Fuel includes the labor and non-labor costs for planning and implementing power supply portfolios to provide reliable service to native load and to capitalize on market opportunities including purchasing fuel for the operating companies' electric generation system (excluding nuclear) and resource planning and acquisition including purchase power and account management.	Cost Causative	MWH Generation	Energy Markets - Fuel using MWH generation to allocate costs is reasonable because the costs are directly related to the purchase of fuel for generation.	35.3947%
200137	455	Energy Supply Miscellaneous Power Expense FERC 506, 539, & 549	Energy Supply Miscellaneous Power Expense FERC 506, 539, & 549 services include Energy Supply operations performance services labor and non-labor costs for non-management employees with the following accountabilities: Develop / suggest / implement improvements for multiple power plants, standardize best practices and process improvements across multiple power plants, establish operations and maintenance policies and procedures for multiple power plants.	Cost Causative	MWH Generation	Energy Supply Miscellaneous Power Expense FERC 506, 539, & 549 using MWH generation to allocate costs is reasonable because the costs are directly related to the support of electric generation facilities.	35.3947%
200138	458	Energy Supply Operation Supervision & Engineering (S&E) FERC 500, 535, & 546	Energy Supply Operation Supervision & Engineering (S&E) FERC 500, 535, & 546 services include labor and expenses incurred in the general supervision and direction of the operation of steam powered generation stations, hydraulic power generating stations, and other power generating stations.	Cost Causative	MWH Generation	Energy Supply Operation Supervision & Engineering (S&E) FERC 500, 535, & 546 using MWH generation to allocate costs is reasonable because the costs are directly related to the support of electric generation facilities.	35.3947%
200139	461	Energy Supply Maintenance Supervision & Engineering (S&E) FERC 510, 541, & 551	Energy Supply Maintenance Supervision & Engineering (S&E) FERC 510, 541, & 551 services which include management and performance labor and non-labor costs for the following accountabilities: Researching, reviewing, recommending and facilitating the selection of technological alternatives for improved plant and environmental performance. Manage uniform project management process (policies). Planning for physical plant modifications, which includes consolidation and management of short-term and long-term plans for physical plant modifications. Develop and execute innovative technology projects such as: biomass, solar, wind. Implement enterprise project management (EPM) and planning tools. Establish uniform technology, design & equipment standards.	Cost Causative	MWH Generation	Energy Supply Maintenance Supervision & Engineering (S&E) FERC 510, 541, & 551 using MWH generation to allocate costs is reasonable because the costs are directly related to the support of electric generation facilities.	35.3947%
200143	456	Energy Supply Miscellaneous Power Expense NSPM & NSPW FERC 506, 539, & 549	Energy Supply Miscellaneous Power Expense NSPM & NSPW FERC 506, 539, & 549 services include Energy Supply operations performance services labor and non-labor costs for non-management employees with the following accountabilities: Develop / suggest / implement improvements for multiple power plants, standardize best practices and process improvements across multiple power plants, establish operations and maintenance policies and procedures for multiple power plants. This allocation is used when NSPM & NSPW jurisdictions are benefiting from the services.	Cost Causative	MWH Generation	Energy Supply Miscellaneous Power Expense NSPM & NSPW FERC 506, 539, & 549 using MWH generation to allocate costs is reasonable because the costs are directly related to the support of electric generation facilities.	93.8813%
200144	459	Energy Supply Operation Supervision & Engineering (S&E) NSPM & NSPW FERC 500, 535, & 546	Energy Supply Operation Supervision & Engineering (S&E) NSPM & NSPW FERC 500, 535, & 546 services include labor and expenses incurred in the general supervision and direction of the operation of steam powered generation stations, hydraulic power generating stations, and other power generating stations. This allocation is used when NSPM & NSPW jurisdictions are benefiting from the services.	Cost Causative	MWH Generation	Energy Supply Operation Supervision & Engineering (S&E) NSPM & NSPW FERC 500, 535, & 546 using MWH generation to allocate costs is reasonable because the costs are directly related to the support of electric generation facilities.	93.8813%

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200145	462	Energy Supply Maintenance Supervision & Engineering (S&E) NSPM & NSPW FERC 510, 541, & 551	Energy Supply Maintenance Supervision & Engineering (S&E) NSPM & NSPW FERC 510, 541, & 551 services which include management and performance labor and non-labor costs for the following accountabilities: Researching, reviewing, recommending and facilitating the selection of technological alternatives for improved plant and environmental performance. Manage uniform project management process (policies). Planning for physical plant modifications, which includes consolidation and management of short-term and long-term plans for physical plant modifications. Develop and execute innovative technology projects such as: biomass, solar, wind. Implement enterprise project management (EPM) and planning tools. Establish uniform technology, design & equipment standards. This allocation is used when NSPM & NSPW jurisdictions are benefiting from the services.	Cost Causative	MWH Generation	Energy Supply Maintenance Supervision & Engineering (S&E) NSPM & NSPW FERC 510, 541, & 551 using MWH generation to allocate costs is reasonable because the costs are directly related to the support of electric generation facilities.	93.8813%
200146	429	Energy Markets - Regulated Trading	Energy Markets - Regulated Trading services include the labor and non-labor costs of providing electric trading services to the operating companies' electric generation systems, including load management, system optimization and origination.	Cost Causative	MWH Hours Sold	Energy Markets - Regulated Trading using MWH hours sold to allocate costs is reasonable because there is a cost causative relationship between regulated trading activities and the MWH hours sold.	35.7964%
200147	554	Business Objects	Business Objects includes the labor and non-labor costs for the application that provides critical reporting from data universes and tables.	Cost Causative	No. of Business Objects Users	Business Objects using No. of Business Object users to allocate costs is reasonable because the costs are directly related to users who can access the application.	50.0218%
200148	500; 524	Business Systems	Business Systems services includes the costs of providing assistance to computer users across the company. Specifically computer technology risk, software maintenance on applications Distributed to all users (e.g. Microsoft PC tools), governance and project management over all IT projects, fixed management fees with outside vendors, business analytics costs, corrective and preventative maintenance, security, data backup and recovery, help desk, and amortization of outside vendor fees and costs that are not specific to an application that has a specific allocator.	Cost Causative	No. of Computers	Business Systems using No. of computers to allocate costs is reasonable because there is a cost causative relationship between the No. of computers and the cost to support them.	49.1506%
200149	534	Customer & Enterprise Solutions (CES)	Customer & Enterprise Solutions (CES) includes the labor and non-labor costs for the leadership of the Customer & Enterprise Solutions organization and their administrative support staff.	Cost Causative	No. of Computers/ No. of Customers/ No. of Employees	Customer & Enterprise Solutions (CES) using a ratio of No. of Computers/Customers/Employees to allocate costs is reasonable because there is a cost causative relationship with the operations supported by CES.	45.3742%
200150	520	Interactive Voice Response (IVR)	Interactive Voice Response (IVR) includes the labor and non-labor costs for the application development and maintenance of the Interactive Voice Response system which interacts with a customer calling Xcel Energy call centers. It is intended to help service customers without invoking a call center agent. If the call needs to be handled by an agent, account information and the reason for the call is determined which helps route the call to the appropriate agent.	Cost Causative	No. of Contacts	Interactive Voice Response (IVR) using No. of contacts to allocate costs is reasonable because this system is used to take and route customer calls and benefits customers using the call centers.	34.0532%
200151	447	Customer Billing FERC 903	Customer Billing FERC 903 includes the labor and non-labor costs related to the delivery of billing statements, letters and notices to Xcel customers including postage and outside services costs, oversight and administration of customer billing area, research of billing exceptions, providing escalated customer service assistance with regard to billing issues resolution, and process remittances and receivables. This allocation is used when all four jurisdictions are benefiting from the services.	Cost Causative	No. of Customer Bills	Customer Billing FERC 903 using No. of customer bills to allocate costs is reasonable because the costs are directly related to customer billing activities.	39.0927%
200152	436	Customer Care FERC 902	Customer Care FERC 902 services includes the labor and non-labor costs for meter reading of retail and wholesale customers and determining consumption for billing purposes as well as executing field collections.	Cost Causative	No. of Customers	Customer Care FERC 902 using No. of customers to allocate costs is reasonable because the costs are directly related to customers.	38.2987%
200153	185	Customer Safety Advertising & Information Costs	Customer Safety Advertising & Information costs services includes the labor and non-labor costs associated with public safety advertising, information and education.	Cost Causative	No. of Customers	Customer Safety Advertising & Information Costs using No. of customers to allocate costs is reasonable because the costs are directly related to customers.	38.3714%
200154	403	Customer Service Information Technology (IT) FERC 903	Customer Service Information Technology (IT) FERC 903 services includes the labor and non-labor costs for IT applications related customer billing to customers, call center support and credit and collections.	Cost Causative	No. of Customers	Customer Service Information Technology (IT) FERC 903 using No. of customers to allocate costs is reasonable because the costs are directly related to customers.	38.3714%
200155	435	Customer Care FERC 903	Customer Care FERC 903 services includes the labor and non-labor costs for contact centers, remittance processing, credit and collections, customer resource management, and contact center training. This allocation is used when all four jurisdictions are benefiting from the services such as responding to residential customer inquiries regarding billings and outages, handling inbound credit calls, outbound collections calls, managing accounts receivables, training call center staffs, developing contact center call forecasts.	Cost Causative	No. of Customers	Customer Care FERC 903 using No. of customers to allocate costs is reasonable because the costs are directly related to customers.	38.3714%
200156	437	Customer Care FERC 901	Customer Care FERC 901 services includes the labor and non-labor costs for the leadership of the customer care organization and their administrative support staff such as consulting costs to support overall Customer Care organizational operations.	Cost Causative	No. of Customers	Customer Care FERC 901 using No. of customers to costs is reasonable because the costs are directly related to customers.	38.3714%

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SAP	JDE						
Cost Center	**Work Order No.**	**Cost Center Description**	**Description of Services Provided**	**General Allocator/ Cost Causative**	**Allocation Method**	**Reasonableness of Allocation Method**	**NSPM Allocation Percent**
200159	405	Customer Service Information Technology (IT) NSPM & NSPW FERC 903	Customer Service Information Technology (IT) NSPM & NSPW FERC 903 services includes the labor and non-labor costs for IT applications related customer billing to customers, call center support and credit and collections. This allocation is used when NSPM & NSPW jurisdictions are benefiting from the services.	Cost Causative	No. of Customers	Customer Service Information Technology (IT) NSPM & NSPW FERC 903 using No. of customers to allocate costs is reasonable because the costs are directly related to customers.	85.1316%
200160	439	Customer Care NSPM & NSPW FERC 903	Customer Care NSPM & NSPW FERC 903 services includes the labor and non-labor costs for contact centers, and credit and collections, such as responding to commercial customers inquiries at the Business Solution Center. This is primarily used by the Customer Care organization when NSPM and NSPW jurisdictions are benefiting from the services.	Cost Causative	No. of Customers	Customer Care NSPM & NSPW FERC 903 using No. of customers to allocate costs is reasonable because the costs are directly related to customers.	85.1316%
200161	446	Customer Care Low Income Assistance FERC 908	Customer Care Low Income Assistance FERC 908 services includes the labor and non-labor costs associated with the low income energy customer program such as answering calls from customers for referral to low income assistance agencies, providing information to the agencies in order to process applications for assistance, take pledges/commitments from agencies and process payments from agencies.	Cost Causative	No. of Residential Customers	Customer Care Low Income Assistance FERC 908 using No. of residential customers to allocate costs is reasonable because the costs are directly related to customers.	42.7675%
200162	519	Call Logging and Quality Management (CL/QM) FERC 903	Call Logging and Quality Management (CL/QM) FERC 903 includes the labor and non-labor operating costs for the application development and maintenance of the Call Logging and Quality Management system which is used to monitor and record calls for contact center training and leadership teams.	Cost Causative	No. of Customers/ No. of Contacts	Call Logging and Quality Management (CL/QM) FERC 903 using a ratio of no. of customers/no. of contacts to allocated costs is reasonable because the system benefits current and potential customers using the call centers.	36.2123%
200163	181	Employee Communications	Employee Communications includes the labor and non-labor costs for the development and enhancement of employee awareness and understanding of the company's strategies, priorities, decisions and performance objectives. It develops and produces regular communication vehicles, including TODAY (daily news bulleting on intranet); XTRA (monthly print publication for all employees and retirees); All Managers E-mail (real-time communication for employees who supervise and manage others); Focus on Financials for all employees; targeted communications for specific business areas, such as Human Resources, and employee meetings.	Cost Causative	No. of Employees	Employee Communications using No. of Employees to allocate costs is reasonable because the costs are directly related to employees.	48.5194%
200164	198	Payroll	Payroll services include the labor and non-labor costs for processing payroll including consolidation of time collection, calculation of salaries and wages, administration of employee deductions, account Distribution and reconciliation, allocation and accounting for employment taxes and compliance reports.	Cost Causative	No. of Employees	Payroll using No. of Employees to allocate costs is reasonable because the costs are directly related to employees.	48.5194%
200165	515; 521; 552	Employee Management Systems	Employee Management Systems includes the labor and non-labor costs for the Security Operations Center (SOC), Time capture and processing for payroll and accounting and Human Resources software. These applications and services provide services for the whole company related to enterprise security, including physical access, security monitoring and investigations, payroll and time accounting and employee information databases.	Cost Causative	No. of Employees	Employee Management Systems using No. of Employees to allocate costs is reasonable because the costs are directly related to employees.	48.5194%
200166	190; 197; 199	Human Resources (Diversity/Safety/Employee Relations)	Human Resources (Diversity/Safety/Employee Relations) includes the labor and non-labor costs for work performed for operating and affiliate company employees, such as diversity programs, providing workforce relations resources for labor agreements, arbitration, and training. Manage, design, and implement Corporate Safety initiatives. Staffing administration for non-bargaining positions and provides Affirmative Action plans (development) and government audit management (compliance).	Cost Causative	No. of Employees	Human Resources (Diversity/Safety/Emp Relations) using No. of Employees to allocate Human Resources costs is reasonable because the costs are directly related to employees.	48.6004%
200167	508; 550	e-Business	The e-Business system includes the labor and non-labor costs associated with the corporate electronic business infrastructure.	Cost Causative	No. of Employees	e-Business using No. of Employees to allocate costs is reasonable because the costs benefit employees.	48.6004%
200168	517	Gas Management System (GMS) FERC 866 & 880	Gas Management System (GMS) FERC 866 & 880 supports Xcel Energy gas transportation business including contracts, nominations/allocations, end-user measurement, imbalance management, and input for billing. also supports gas system supply, other balancing services. Costs include labor and non-labor for the application development and maintenance of the Gas Management System.	Cost Causative	No. of Gas Customers	Gas Management System (GMS) FERC 866 & 880 using No. of gas customers to allocate costs is reasonable because this system benefits gas customers.	0.0017%
200169	504; 537; 553	Energy Supply Systems Miscellaneous FERC 417.1, 506, 539, & 549	Energy Supply Systems Miscellaneous FERC 417.1, 506, 539, & 549 includes the labor and non-labor costs for the non-critical applications that support the Energy Supply area. Such as Emissions Tracker, Labworks, SAP WAM, Documentum and Meridian.	Cost Causative	No. of WAM ES Users	Energy Supply Systems Miscellaneous FERC 417.1, 506, 539, & 549 using the no. of WAM ES users to allocate the costs is reasonable because there is a direct causal relationship with the operations supported by WAM ES.	36.4855%
200170	518; 540	Meter Reading and Monitoring Systems FERC 902	Meter Reading and Monitoring Systems FERC 902 includes the labor and non-labor operating costs for the application development and maintenance of the software applications needed to read and monitor gas and electric meters, including Meter Data Lake.	Cost Causative	No. of Meters	Meter Reading and Monitoring Systems FERC 902 using No. of meters to allocate costs is reasonable because there is a direct causal relationship with the companies use of systems to monitor meters.	35.5498%

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200171	503; 555	Customer Resource System (CRS) FERC 903	Customer Resource System (CRS) FERC 903 includes the labor and non-labor costs for the CRS system, specifically, application development and maintenance costs, licensing fees, server system costs and technology risk costs specific to disaster recovery of this application. CRS is Xcel Energy's customer service and billing system.	Cost Causative	No. of Meters/ No. of Contacts	Customer Resource System (CRS) FERC 903 using a ratio of no. of meters/no. of contacts to allocate costs is reasonable because there is a direct causal relationship with the operations supported by CRS.	34.8015%
200172	523	Network	Network services include the labor and non-labor costs for the operation, maintenance, and management of Xcel Energy's internal and external Information Technology Network. This includes circuits, firewalls and communication assets.	Cost Causative	Phones/ Radios/ Computers	Network using a ratio of phones/radios/computers to allocate costs is reasonable because the network supports these major items.	50.2755%
200173	129	Generation Trading/Native Hedge - Back Office	Generation Trading/Native Hedge - Back Office includes the labor and non-labor costs associated with oversight and administration of accounting related trading costs including generation trading and native hedge. This allocator should be primarily used by Accounting and Finance, or others providing Administrative & General (A&G) activities when energy trades are executed using one of Xcel Energy Utilities generation resources.	Cost Causative	Joint Operating Agreement Labor Hours Ratio	Gen/Prop Trading - Back Office use of Joint Operating Agreement Labor Hours Ratio is reasonable because there is a direct correlation between the front office activities and the mid-office and back-office activities. It is required to use the Joint Operating Agreement for the Proprietary split for these accounting and trading costs.	31.5833%
200174	145	Generation Trading/Native Hedge - Mid Office FERC 557	Generation Trading/Native Hedge - Mid Office FERC 557 includes the labor and non-labor costs associated with independent evaluation and risk measurement of trading and generation book transactions, including preparing daily P&L (profit and loss) reports and individual trader profit and loss reports for the prop book, daily generation book valuation reports for each system showing all net fuel positions and any forward sales values and/or hedges, ensuring that margin reporting follows all SEC rules and GAAP reporting and that credit and risk policies and procedures are complied with.	Cost Causative	Joint Operating Agreement Labor Hours Ratio	Gen/Prop Trading - Mid Office FERC 557 use of Joint Operating Agreement Labor Hours Ratio is reasonable because there is a direct correlation between the front office activities and the mid-office and back-office activities. It is required to use the Joint Operating Agreement for the Proprietary split for these accounting and trading costs.	37.9151%
200176	412	Marketing & Sales	Marketing & Sales services includes the labor and non-labor costs for marketing and sales services for the operating companies for their customers including strategic planning, segment identification, business analysis, sales planning, customer service, promoting products to the business market, and providing regulatory and policy support with respect to utility energy efficiency and demand response program design, evaluation, measurement and verification, cost effectiveness testing , and cost recovery.	Cost Causative	Revenue	Marketing & Sales using revenue to allocate costs is reasonable because Marketing & Sales support the revenue-producing operations of the company.	42.2185%
200177	418	Rates & Regulation - Electric	Rates & Regulation - Electric includes the labor and non-labor costs for determining the regulated utilities' electric utility revenue requirements and rates for electric customers regulatory strategy, coordinating the regulatory compliance requirements, establishing and maintaining relationships with regulatory bodies, policy development of regulatory and legislative strategy, preparing and organizing rate case filings.	Cost Causative	Revenue	Rates & Regulation Electric using revenue to allocate costs is reasonable because they are responsible for setting revenue requirements.	31.3292%
200178	417	Rates & Regulation	Rates & Regulation includes the labor and non-labor costs for determining the regulated utilities' revenue requirements and rates for electric and gas customers regulatory strategy, coordinating the regulatory compliance requirements, establishing and maintaining relationships with regulatory bodies, policy development of regulatory and legislative strategy, preparing and organizing rate case filings.	Cost Causative	Revenue	Rates & Regulation using revenue to allocate costs is reasonable because they are responsible for setting revenue requirements.	31.3292%
200180	528	EMS-Shared (Energy Management System-SCADA) FERC 556, 561.2, & 581	EMS-Shared (Energy Management System-SCADA) FERC 556, 561.2, & 581 provides supervisory control and data acquisition of substation devices through Remote Terminal Units (RTU's). EMS-Shared system includes the labor and non-labor costs for the application development and maintenance of the Electric Transmission, Distribution and Production Plant information operations.	Cost Causative	Electric Production Plant/ Electric Transmission Plant/ Electric Distribution Plant	EMS-Shared (Energy Management System-SCADA) FERC 556, 561.2, & 581 using a ratio of electric production plant/electric transmission plant/electric distribution plant to allocate costs is reasonable because there is a direct causal relationship with the operations supported by EMS-Shared.	41.1404%
200181	464	Energy Supply Environmental Policy & Services	Energy Supply Environmental Policy & Services include the labor and non-labor costs dedicated to air quality, renewable energy, innovative technology and climate change, develop corporate compliance strategy, regulatory agency interaction (both at the federal and/or state level), permitting and compliance reporting, waste management, combustion byproducts management, environmental compliance auditing, provide support to the Environmental Council and assist with environmental communications strategies.	Cost Causative	Electric Production Plant/ Electric Transmission Plant/ Electric Distribution Plant/ Gas Transmission Plant/ Gas Distribution Plant	Energy Supply Environmental Policy & Services using gross plant assets to allocate costs is reasonable because the costs are directly related to the environmental policies and services which are generated by the operation and ownership of the assets.	38.9619%
200182	465	Energy Supply Environmental Policy & Services NSPM & NSPW	ES Environmental Policy & Services NSPM & NSPW functions which include the labor and non-labor costs dedicated to air quality, renewable energy, innovative technology and climate change, develop corporate compliance strategy, regulatory agency interaction (both at the federal and/or state level), permitting and compliance reporting, waste management, combustion byproducts management, environmental compliance auditing, provide support to the Environmental Council and assist with environmental communications strategies. This allocation is used when NSPM and NSPW jurisdictions are benefiting from the services.	Cost Causative	Electric Production Plant/ Electric Transmission Plant/ Electric Distribution Plant/ Gas Transmission Plant/ Gas Distribution Plant	ES Environmental Policy & Services NSPM & NSPW using gross plant assets to allocate costs is reasonable because the costs are directly related to the environmental policies and services which are generated by the operation and ownership of the assets.	86.0579%

XES Allocation Descriptions, Methods and NSPM Percentages

2022 Test Year Budget

SAP	JDE						
Cost Center	**Work Order No.**	**Cost Center Description**	**Description of Services Provided**	**General Allocator/ Cost Causative**	**Allocation Method**	**Reasonableness of Allocation Method**	**NSPM Allocation Percent**
200184	516	PowerPlan	PowerPlan includes the labor and non-labor operating costs for PowerPlan, which is the capital asset business system which includes the following modules. Fixed Assets, Power Tax, Property Tax, Projects, Budgets, Cost Repository, Depreciation studies and Depreciation forecast. This includes the application development and maintenance costs, licensing fees, server system costs and technology risk costs specific to disaster recovery of this application.	Cost Causative	Total Plant	PowerPlan using total plant to allocate costs is reasonable because there is a direct causal relationship with the companies using PowerPlan to manage plant assets.	41.6215%
200805		HomeSmart Revenue – Non-Utility 417.1	HomeSmart Revenue – Non-Utility 417,1 includes the labor and non-labor costs, including but not limited to business administration, advertising, marketing, software and technology costs related to all HomeSmart activity (Equipment Sales, Service Plan, and Service Call) across MN & CO Jurisdictions.	Cost Causative	Revenues	HomeSmart Revenue – Non-Utility 417,1 to allocate costs is reasonable because the costs are directly related to revenue generating activities of the business activity.	72.4224%
200806		HomeSmart Customers – Non-Utility 417.1	HomeSmart Customers – Non-Utility 417.1 includes the labor and non-labor costs, including but not limited to business administration, advertising, marketing, software and technology costs related to HomeSmart Service Plan activity across MN & CO Jurisdictions.	Cost Causative	No. of Customers	HomeSmart Customers – Non-Utility 417.1 to allocate costs is reasonable because the costs are directly related to customer related activities of the business activity.	72.3632%

XES Allocation Descriptions, Methods and NSPM Percentages (Using Allocated FTE Hours)

2022 Test Year Budget

SAP Cost Center	JDE Work Order No.	Cost Center Description	Description of Services Provided	General Allocator/ Cost Causative	Allocation Method	Reasonableness of Allocation Method	NSPM Alloc Percent FTE Hours
200063	110	Executive - Corporate Governance	Executive Corporate Governance includes the labor and non-labor costs for executive corporate management, long-term business strategy development and other programs that ensure the continuity and development of management. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc.	General Allocator	Assets/Revenue/FTE Hours	Executive - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore, the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative effect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative effect on the consolidated business. FTE Hours is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	37.4088%
200064	115	Shareholder - Corporate Governance	Shareholder - Corporate Governance includes the labor and non-labor costs for serving as liaison between Xcel Energy BOD and the shareholders, manages employee/executive stock award matters, liaison between Xcel Energy and the proxy advisory group, monitoring stock ownership patterns, planning shareholder meetings, coordinating the transfer agent and shareholder record keeping functions. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc.	General Allocator	Assets/Revenue/FTE Hours	Shareholder - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore, the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative effect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative effect on the consolidated business. FTE Hours is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	37.4088%
200065	116	Investor Relations - Corporate Governance	Investor Relations - Corporate Governance includes the labor and non-labor costs for communications to investors and the financial community, providing management with feedback from investors, assisting in the communication to investors of debt and equity securities issuances, assists in the development of presentations for Board of Directors, develops and delivers Xcel Energy's credit story to credit rating agencies, develops and presents Xcel Energy's investment story to investors, reviews all public financial documents for accuracy and completeness and distributes all financial releases. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc.	General Allocator	Assets/Revenue/FTE Hours	Investor Relations - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore, the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative effect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative effect on the consolidated business. FTE Hours is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	37.4088%
200066	121	Accounting, Reporting & Tax - Corporate Governance	Accounting, Reporting & Tax - Corporate Governance includes the labor and non-labor costs associated with preparing and filing consolidated reporting and financial statements, preparing consolidated budgets, completing the consolidation process, maintaining the books and records of Xcel Energy Inc. and Service Company, composing the corporate-wide regulatory accounting policy and compliance, Sarbanes-Oxley (SOX) documentation and compliance, and Chief Financial Officer activities related to the Audit Committee. Provides financial leadership to Xcel Energy and provides policies, controls, and leadership to the Financial Operations business area. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc.	General Allocator	Assets/Revenue/FTE Hours	Accounting, Reporting & Tax - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore, the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative effect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative effect on the consolidated business. FTE Hours is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	37.4088%
200067	131	Audit Services - Corporate Governance	Audit Services corporate governance includes the labor and non-labor costs associated with the financial operations and information system audits of the holding company and service company; evaluating and improving risk management, corporate internal control guidelines and procedures; ethical conduct and the implementation of best practices, reviewing financial reporting requirements and controls under Sarbanes-Oxley legislative requirements, auditing of consolidated financial statements and activities related to the Audit Committee, performing audits and reviews for compliance with regulatory and legal requirements an contracts with vendors and other parties, providing consulting services to management for operational and process improvement reviews, assistance in internal investigations of fraud, administering the corporate compliance hotline, conflict of interest investigations, or other potential violations of the Xcel Energy Code of Conduct. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc.	General Allocator	Assets/Revenue/FTE Hours	Audit Services - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore, the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative effect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative effect on the consolidated business. FTE Hours is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	37.4088%
200068	141	Corporate Finance, Treasury & Cash Management - Corporate Governance	Corporate Finance, Treasury & Cash Management - Corporate Governance includes the labor and non-labor costs related to equity and debt securities issuance, relationships with financial institutions, cash management, investing activities and monitoring the capital markets, holding company commercial paper transactions, compliance with debt covenants, corporate-wide protection of assets from catastrophic loss using risk financing mechanisms including captive risk retention and design and negotiation of insurance contracts with commercial and industry mutual underwriters (Service Company portion of Auto Liability, Cyber, and various other insurance policies), supervising the asset management firms for the Pension Fund and 401k benefits. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc.	General Allocator	Assets/Revenue/FTE Hours	Corporate Finance, Treasury & Cash Management - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore, the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative effect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative effect on the consolidated business. FTE Hours is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	37.4088%

XES Allocation Descriptions, Methods and NSPM Percentages (Using Allocated FTE Hours)

2022 Test Year Budget

SAP Cost Center	JDE Work Order No.	Cost Center Description	Description of Services Provided	General Allocator/ Cost Causative	Allocation Method	Reasonableness of Allocation Method	NSPM Alloc Percent FTE Hours
200069	143	Risk Management - Corporate Governance	Risk Management Corporate Governance includes the labor and non-labor costs of providing administration of the Transaction Review Committee which handles contract and deal approvals for Commercial Operations, Resource Planning and Energy Supply, provides analysis associated with key risks facing Xcel Energy Inc., negotiates and manages required security (e.g., bank letters of credit, bonds and guarantees among others); reviews and approves all documents requiring Contracts area sign-off. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc.	General Allocator	Assets/Revenue/FTE Hours	Risk Management - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore, the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative effect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative effect on the consolidated business. FTE Hours is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	37.4088%
200070	161	Corporate Strategy & Business Development - Corporate Governance	Corporate Strategy & Business Development - Corporate Governance includes the labor and non-labor costs associated with providing leadership for the implementation of company-wide business strategies and plans; portfolio management including the evaluation of potential opportunities for mergers, acquisitions and divestitures; providing financial, analytical and reporting support; researching and providing business intelligence information. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc.	General Allocator	Assets/Revenue/FTE Hours	Corporate Strategy & Business Development - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore, the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative effect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative effect on the consolidated business. FTE Hours is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	37.4088%
200071	171	Legal - Corporate Governance	Legal - Corporate Governance includes the labor and non-labor costs for anticipating and fulfilling the legal needs of Xcel Energy, its Board of Directors, officers, legal entities, business areas and corporate operations to protect the company's assets and to minimize potential liability. Provides services related to labor and employment law pertaining to Service Company employees, litigation, contracts, rates and regulation, environmental matters and other legal matters. Supports Xcel Energy and its subsidiaries in fulfilling corporate and business area strategies ranging from maintaining/improving regulatory relationships to continued leadership on environmental issues. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc.	General Allocator	Assets/Revenue/FTE Hours	Legal - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore, the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative effect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative effect on the consolidated business. FTE Hours is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	37.4088%
200072	180	Communications - Corporate Governance	Communications - Corporate Governance includes the labor and non-labor costs to assist and ensure Executive Management, Investor Relations and others communicate appropriately with shareholders, the public, and other key stakeholder audiences. Key projects include: development and production of the annual report and other communications to investors; speeches, videos, and major presentations delivered by top executives; and speeches, displays, video and presentations for the company's annual meeting of shareholders. Media Relations contributes to building Xcel Energy's reputation by developing media and public relations strategies for major company initiatives and issues; responding to news media inquiries; working pro-actively with the media to forward story ideas and information about company events, policies and actions, and providing media training for company spokespersons. Media Relations also plays a key role in crisis communications and emergency preparedness efforts. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc.	General Allocator	Assets/Revenue/FTE Hours	Communications - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore, the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative effect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative effect on the consolidated business. FTE Hours is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	37.4088%
200073	189	Human Resources - Corporate Governance	Human Resources - Corporate Governance includes the labor and non-labor costs for executive officers' and Service Company employees' compensation plans, corporate HR policies, executive policy benefit plans, payroll services for Service Company and the employees' handbook. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc.	General Allocator	Assets/Revenue/FTE Hours	Human Resources - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore, the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative effect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative effect on the consolidated business. FTE Hours is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	37.4088%
200074	529; 549; 551; 561	Corporate Systems – Corporate Governance	Corporate Systems – Corporate Governance includes the labor and non-labor costs for enterprise-wide corporate systems.	General Allocator	Assets/Revenue/FTE Hours	Corporate Systems - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore, the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative effect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative effect on the consolidated business. FTE Hours is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	37.4088%

XES Allocation Descriptions, Methods and NSPM Percentages (Using Allocated FTE Hours)

2022 Test Year Budget

SAP Cost Center	JDE Work Order No.	Cost Center Description	Description of Services Provided	General Allocator/ Cost Causative	Allocation Method	Reasonableness of Allocation Method	NSPM Alloc Percent FTE Hours
200075	114	Board of Directors - Corporate Governance	Board of Directors - Corporate Governance includes the labor and non-labor costs related to the Board of Directors (BOD). BOD costs may include Directors fees, retirement expenses and replacement fees; Board/Committee meetings and BOD related consulting. Corporate governance activities are generally services that are performed on behalf of all Xcel Energy operating companies and affiliates, including Xcel Energy Inc.	General Allocator	Assets/Revenue/FTE Hours	Board of Directors - Corporate Governance uses the three-factor formula because it reflects the complexity, risk and overall business activity levels that drive corporate governance costs and measures the benefits received from those activities. Corporate Governance includes overall management of the corporation and benefits all companies; therefore, the General Allocator is the most appropriate method of allocation. Assets are used because the greater the value of a subsidiary's assets the more focus will be placed on that subsidiary's operations. Due to its relative effect on the consolidated business. Revenues are used because the larger the subsidiary's revenue the more focus will be placed on that subsidiary's operations due to its relative effect on the consolidated business. FTE Hours is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.	37.4088%
200076	182	Xcel Foundation	Xcel Foundation services includes the labor and non-labor costs associated with the management and administration of the Xcel Energy Foundation.	General Allocator	Assets/Revenue/FTE Hours	Xcel Foundation services that could not be directly charged to a specific legal entity and are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	37.4780%
200077	184	Branding	Branding services includes the labor and non-labor costs for brand advertising and management of community affairs programs such as employee volunteerism, educational programs and community events, the company's investment in major sponsorships such as the Xcel Energy Center as well as ensuring that such sponsorships and related activities support the company's brand, mission and values.	General Allocator	Assets/Revenue/FTE Hours	Branding services that could not be directly charged to a specific legal entity and are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	37.4780%
200078	410	Governmental Affairs	Governmental Affairs includes the labor and non-labor costs associated with the interpretation of laws regulations and environmental policy to ensure compliance and cost effectiveness for Xcel Energy customers and stockholders Internal legislative policy development and issues management, appraise management and internal customers of political and policy trends and developments, develop and maintain relationships with regulatory officials and staff.	General Allocator	Assets/Revenue/FTE Hours	Governmental Affairs services that could not be directly charged to a specific legal entity and are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	37.5013%
200079	409	Federal Lobbying	Federal Lobbying services includes the labor and non-labor costs for federal and state lobbying activities and the federal Political Action Committee (PAC).	General Allocator	Assets/Revenue/FTE Hours	Federal Lobbying services that could not be directly charged to a specific legal entity and are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are provided to a subset of companies based on who benefits from the services. These costs are recorded in FERC 426.4.	37.5013%
200080	135	Capital Asset Accounting	Capital Asset Accounting includes the labor and non-labor costs associated with operating and non-operating company capital asset accounting, budgeting, regulatory reporting, business area support for utility areas, and operating company budgeting support.	General Allocator	Assets/Revenue/FTE Hours	Capital Asset Accounting services that could not be directly charged to a specific legal entity and are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	42.6226%
200081	120	Accounting, Reporting & Taxes	Accounting, Reporting & Taxes services includes the labor and non-labor costs for preparation of operating and non-operating financial statements, tax returns and reporting, performing accounting for the employee benefit plans, ensuring compliance with applicable laws and regulations of the operating and non-operating companies; composing the corporate-wide regulatory accounting policy, and coordinating the budgeting process with the operating and non-operating companies.	General Allocator	Assets/Revenue/FTE Hours	Accounting Reporting & Taxes services that could not be directly charged to a specific legal entity and are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	42.7022%
200082	130	Audit Services	Audit Services includes the labor and non-labor costs for auditing operating and non-operating companies, evaluating and improving risk management, ethical conduct and the implementation of best practices for operating and non-operating companies, conducting financial operations and information system audits, performing audits and reviews for compliance with regulatory and legal requirements and contracts with vendors and other parties; establishing and reviewing internal controls for operating and non-operating companies, establishing and reviewing SOX compliance requirements/control testing and evaluating contract risks for the operating and non-operating companies.	General Allocator	Assets/Revenue/FTE Hours	Audit Services that could not be directly charged to a specific legal entity and are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	42.7022%
200083	140	Corporate Finance, Treasury & Cash Management	Corporate Finance, Treasury & Cash Management services includes the labor and non-labor costs related to equity and debt securities issuance, cash management, relationships with financial institutions, compliance with debt covenants, Service Company portion of General and Excess liability insurance, and management of the Pension Fund and 401k benefits for operating companies.	General Allocator	Assets/Revenue/FTE Hours	Corporate Finance, Treasury & Cash Management services that could not be directly charged to a specific legal entity and are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	42.7022%

XES Allocation Descriptions, Methods and NSPM Percentages (Using Allocated FTE Hours)

2022 Test Year Budget

SAP Cost Center	JDE Work Order No.	Cost Center Description	Description of Services Provided	General Allocator/ Cost Causative	Allocation Method	Reasonableness of Allocation Method	NSPM Alloc Percent FTE Hours
200084	142	Risk Management	Risk Management develops and negotiates security agreements with counterparties; reviews high-risk vendor creditworthiness for the Environmental Services group; supports wind generation, solar carbon offsets, emission allowances, bundled energy and RECs, biomass and other renewable energy purchase agreements; participates in industry contracts working groups; representing Xcel Energy operating utilities; performs production cost modeling and analysis for corporate budgeting; analyzing value and risks of structured purchases and generation system modifications; performs long range system modeling to evaluate large capacity acquisition alternatives; provides central coordination of annual capital funding process for Distribution and maintains and administers the Risk Registry database, evaluates and prioritizes specific risk mitigations for Distribution assets; develops strategies for Distribution infrastructure including building and implementing stochastic models for asset life-cycle analysis and other ad hoc asset specific requests; creates retail and system load and energy forecasts providing regular updates to senior management and analyses of key drivers; provides data support and analyses for financial disclosures; and provides analyses and reporting of current sales and peak demand levels relative to forecasts.	General Allocator	Assets/Revenue/FTE Hours	Risk Management services that could not be directly charged to a specific legal entity and are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	42.7022%
200086	170	Legal & Claims Services	Legal & Claims Services includes the labor and non-labor costs for operating and non-operating legal services related to: labor and employment law, litigation, rates and regulation, environmental matters, real estate, contracts, and claims services related to casualty, public, and company claims.	General Allocator	Assets/Revenue/FTE Hours	Legal & Claims Services that could not be directly charged to a specific legal entity and are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	42.7022%
200087	123	Accounting, Reporting & Tax - Regulated	Accounting, Reporting & Tax - Regulated includes the labor and non-labor costs associated with operating company revenue accounting, budgeting, regulatory reporting, sales and use taxes, business area support for utility areas, operating company budgeting support, and capital asset accounting.	General Allocator	Assets/Revenue/FTE Hours	Accounting, Reporting & Tax - Regulated services that could not be directly charged to a specific legal entity and are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to regulated companies based on who benefits from the services.	42.7137%
200088	127; 133	Accounting, Reporting, Tax & Audit Services - Regulated Electric	Accounting, Reporting, Tax & Audit Services - Regulated Electric includes the labor and non-labor costs associated specifically with operating company electric utility revenue accounting, budgeting, regulatory reporting, sales and use taxes, business area support for utility areas, operating company budgeting support, capital asset accounting auditing operating companies , evaluating and improving risk management, ethical conduct and the implementation of best practices for operating companies electric utility, conducting financial operations and information system audits, performing audits and reviews for compliance with regulatory and legal requirements and contracts with vendors and other parties; establishing and reviewing internal controls for operating companies electric utility, establishing and reviewing SOX compliance requirements/control testing and evaluating contract risks for the operating companies electric utility. Additionally, costs for electric association dues including Edision Electric Institute (EEI).	General Allocator	Assets/Revenue/FTE Hours	Accounting, Reporting, Tax & Audit Services - Regulated Electric services that could not be directly charged to a specific legal entity and are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to regulated companies with electric operations who benefits from the services.	42.7137%
200089	132	Audit Services - OpCo's & TransCo's	Audit Services - OpCo's & TransCo's includes the labor and non-labor costs for auditing operating companies, evaluating and improving risk management, ethical conduct and the implementation of best practices for operating companies, conducting financial operations and information system audits, performing audits and reviews for compliance with regulatory and legal requirements and contracts with vendors and other parties; establishing and reviewing internal controls for operating companies, establishing and reviewing SOX compliance requirements/control testing and evaluating contract risks for the operating companies.	General Allocator	Assets/Revenue/FTE Hours	Audit Services - OpCo's & TransCo's services that could not be directly charged to a specific legal entity and are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies and Transmission-only companies who benefit from the services.	42.7137%
200090	146	Risk Management - OpCo's & TransCo's	Risk Management - OpCo's & TransCo's includes the labor and non-labor costs of oversight and administrative of operating company risk management work, working with counterparties to establish enabling agreements with operating companies, risk management reports including all operating companies (such as CDAD - Contract Development, Approval & Delegation or TRC- Transaction Review Committee Reporting).	General Allocator	Assets/Revenue/FTE Hours	Risk Management - OpCo's & TransCo's services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies and Transmission-only companies who benefit from the services.	42.7137%
200091	147	Captive Insurance	Captive Insurance - The Property Loss Control Engineers services includes the labor and non-labor costs for each primary Operating Company(s) as well as all of Energy Supply Services. Having an expertise in an area, they lend support to each other and members of Energy Supply, and the Utilities Group, throughout the corporation. Fire Protection, Transformer Maintenance, Turbine Characteristics, Policies and Procedures are some of the areas in which expertise has been developed. This expertise is then shared on a regular basis to the benefit of all OpCo's and it is further shared at periodic Engineering meetings hosted by Hazard Insurance, which bring together Engineers from the OpCo's, the Property Loss Control Engineers and Insurance Company representatives to promote Loss Control.	General Allocator	Assets/Revenue/FTE Hours	Captive Insurance services that could not be directly charged to a specific legal entity and are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies who benefit from the services.	42.7137%

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SAP Cost Center	JDE Work Order No.	Cost Center Description	Description of Services Provided	General Allocator/ Cost Causative	Allocation Method	Reasonableness of Allocation Method	NSPM Alloc Percent FTE Hours
200092	162	Corporate Strategy & Business Development	Corporate Strategy & Business Development services include the labor and non-labor costs associated with providing leadership for the implementation of company-wide business strategies and plans; portfolio management including the evaluation of potential opportunities for mergers, acquisitions and divestitures; providing financial, analytical and reporting support; researching and providing business intelligence information.	General Allocator	Assets/Revenue/FTE Hours	Corporate Strategy & Business Development services that could not be directly charged to a specific legal entity and are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies who benefit from the services.	42.7137%
200093	174	Legal - OpCo's & TransCo's	Legal - OpCo's & TransCo's services include the labor and non-labor costs for operating companies legal services related to: labor and employment law, litigation, rates and regulation, environmental matters, real estate and contracts.	General Allocator	Assets/Revenue/FTE Hours	Legal - OpCo's & TransCo's services that could not be directly charged to a specific legal entity and are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies and Transmission-only companies who benefit from the services.	42.7137%
200094	416	Supply Chain	Supply Chain includes the labor and non-labor costs for operating companies diversity program expenses as well as various dues for specific sponsored agencies (Chamber of Commerce, social service dues, etc.)	General Allocator	Assets/Revenue/FTE Hours	Supply chain services that could not be directly charged to a specific legal entity and are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies who benefit from the services.	42.7137%
200095	430	Energy Supply Asset Management	Energy Supply Asset Management services includes the labor and non-labor costs of providing management support to the Energy Supply organization, maximizing business value of the Energy Supply information systems, developing the business plan, optimizing plant inventory, and leading the development of asset management strategy and implementation.	General Allocator	Assets/Revenue/FTE Hours	Energy Supply Asset Management services that could not be directly charged to a specific legal entity and are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	42.7137%
200096	431	Energy Markets - Business Services	Energy Markets Business Services includes the labor and non-labor costs for financial analysis, budgeting and administrative support, managerial reporting and business planning and process initiatives, independent daily forward valuation and risk measurement of commodity transactions and system fuel and purchase power requirements to meet system loads, as well as proprietary or trading transactions; creates retail system load and energy forecasts providing regular updates to senior management and analyses of key drivers, reviews and provides comments to dealmakers on non-standard agreements and associated confirmation agreements in the areas of coal supply, gas supply, wood fuel, rail, trucking, structured power purchases and nuclear/uranium concentrates and services; provides analyses for electric/gas hedge studies and sensitivities; creates load management forecast, jurisdictional peak demand forecasts, and cost of service studies for energy trading and marketing.	General Allocator	Assets/Revenue/FTE Hours	Energy Markets - Business Services that could not be directly charged to a specific legal entity and are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	42.7137%
200097	533; 535; 539; 542	Accounting and Finance Software Applications Maintenance	Accounting and Finance Software Applications Maintenance services include the labor and non-labor operating costs for the application development and maintenance of the software applications used for accounting and finance business functions.	General Allocator	Assets/Revenue/FTE Hours	Accounting and Finance Software Applications Maintenance - The Business Systems expenses related to maintenance of this system that could not be directly charged to a specific legal entity and are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to a subset of companies based on who benefits from the services.	42.7137%
200098	468	Electric Transmission FERC 566	Electric Transmission FERC 566 services include Transmission electric labor and non-labor costs associated with accounting, budgeting, regulatory reporting, and capital asset accounting.	General Allocator	Assets/Revenue/FTE Hours	Electric Transmission FERC 566 charges that cannot be directly charged to a specific legal entity and are corporate in nature. The three-factor formula is used because these charges are comprised of a broad spectrum of activities and no measurable method of cost causative allocation was found.	42.7137%
200099	469	Electric Distribution FERC 588	Electric Distribution FERC 588 services include electric Distribution labor and non-labor costs associated with accounting, budgeting, regulatory reporting, and capital asset accounting.	General Allocator	Assets/Revenue/FTE Hours	Electric Distribution FERC 588 charges that cannot be directly charged to a specific legal entity and are corporate in nature. The three-factor formula is used because these charges are comprised of a broad spectrum of activities and no measurable method of cost causative allocation was found.	42.7137%
200100	134	Accounting, Reporting, Tax & Audit Services – Regulated Gas	Accounting, Reporting, Tax & Audit Services – Regulated Gas includes the labor and non-labor costs associated specifically with gas utility revenue accounting, budgeting, regulatory reporting, sales and use taxes, business area support for utility areas, capital asset accounting, auditing, evaluating and improving risk management, ethical conduct and the implementation of best practices for operating companies gas utility, conducting financial operations and information system audits, performing audits and reviews for compliance with regulatory and legal requirements and contracts with vendors and other parties; establishing and reviewing internal controls for operating companies gas utility, establishing and reviewing SOX compliance requirements/control testing and evaluating contract risks for the operating companies gas utility. Additionally, costs for gas association dues including American Gas Association (AGA).	General Allocator	Assets/Revenue/FTE Hours	Accounting, Reporting, Tax & Audit Services – Regulated Gas services that could not be directly charged to a specific legal entity and are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies gas utility who benefit from the services.	50.4677%
200101	164	Legal Gas	Legal Gas services include the labor and non-labor costs for operating companies gas utility legal services related to: labor and employment law, litigation, rates and regulation, environmental matters, real estate and contracts. This is primarily used by the General Counsel area.	General Allocator	Assets/Revenue/FTE Hours	Legal Gas services that could not be directly charged to a specific legal entity and are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to the operating companies who benefit from the services.	50.4677%
200102	470	Gas Distribution FERC 880	Gas Distribution FERC 880 services include gas Distribution labor and non-labor costs associated with accounting, budgeting, regulatory reporting, and capital asset accounting.	General Allocator	Assets/Revenue/FTE Hours	Gas Distribution FERC 880 charges that cannot be directly charged to a specific legal entity and are corporate in nature. The three-factor formula is used because these charges are comprised of a broad spectrum of activities and no measurable method of cost causative allocation was found.	50.4677%
200105	125	Accounting & Reporting - NSPM & NSPW	Accounting & Reporting - NSPM & NSPW includes the labor and non-labor costs associated with NSPM & NSPW accounting, budgeting, regulatory reporting, sales and use taxes, business area support for utility areas, operating company budgeting support, and capital asset accounting.	General Allocator	Assets/Revenue/FTE Hours	Accounting & Reporting - NSPM & NSPW services that could not be directly charged to a specific legal entity and are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to NSPM & NSPW who benefit from the services.	86.1580%

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200106	126	Accounting & Reporting Electric - NSPM & NSPW	Accounting & Reporting Electric - NSPM & NSPW includes the labor and non-labor costs associated with NSPM & NSPW accounting, budgeting, regulatory reporting, sales and use taxes, business area support for utility areas, operating company budgeting support, and capital asset accounting specific to the electric utility.	General Allocator	Assets/Revenue/FTE Hours	Accounting & Reporting Electric - NSPM & NSPW services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to NSPM & NSPW electric utility who benefit from the services.	86.1580%
200107	172	Legal - NSPM & NSPW	Legal - NSPM & NSPW services include the labor and non-labor costs for legal services related to: labor and employment law, litigation, rates and regulation, environmental matters, real estate and contracts specific to NSPM & NSPW. This is primarily used by the General Counsel area.	General Allocator	Assets/Revenue/FTE Hours	Legal - NSPM & NSPW services that could not be directly charged to a specific legal entity are corporate in nature. Because these services are comprised of a broad spectrum of activities, no measurable method of cost causative allocation was found to allocate these costs therefore the three-factor formula was used. These services are allocated to NSPM & NSPW who benefit from the services.	86.1580%
200108	N/A	Advanced Metering Infrastructure (AMI)	Advanced Metering Infrastructure (AMI) includes the labor and non-labor costs associated with AMI.	Cost Causative	No. of AMI Enabled Meters	Advanced Metering Infrastructure (AMI) using No. of AMI Enabled Meters to allocate costs is reasonable because there is a cost causative relationship with the companies with AMI enabled meters.	56.2262%
200111	544	Enterprise Application Integration (EAI)	Enterprise Application Integration (EAI) includes the labor and non-labor costs associated with the management of information systems infrastructure and working with IT Project Managers to ensure that new systems are positioned to function as successfully as possible in terms of overall performance and communication with other systems.	Cost Causative	Average of a Select Set of Software Allocators	Enterprise Application Integration (EAI) using average of selected software systems to allocate costs is reasonable because EAI is primarily the server costs supporting the selected software applications and benefits the companies using the software applications.	38.0516%
200112	562	Mainframe Charges	Mainframe Charges include labor and non-labor costs related to mainframe expenses for development, maintenance, and licensing. The Mainframe is comprised of three applications: Time, Gas Management System, and Monitoring Device Management System applications. This is used primarily by the Business Systems Organization.	Cost Causative	Average of a Select Set of Software Allocators	Mainframe Charges expenses cannot be directly charged to a specific legal entity as the system is used by multiple entities. Using an average of selected software systems to allocate costs is reasonable because Mainframe primarily supports these selected software systems.	26.5351%
200115	514	Miscellaneous Applications	Miscellaneous Applications includes the labor and non-labor costs associated with the management of information systems infrastructure and working with IT project managers to ensure that new systems are positioned to function as successfully as possible in terms of overall performance and communication with other systems.	Cost Causative	Average of All Software Percentages	Miscellaneous Applications using average of all software systems to allocate costs is reasonable because Miscellaneous Applications is primarily the server costs supporting the software applications and benefits the companies using the software applications.	34.8985%
200116	441	Distribution Electric Supervision & Engineering (S&E) FERC 580	Distribution Electric Supervision & Engineering (S&E) FERC 580 services includes the labor and expenses incurred in the general supervision and direction of the operation of the electric distribution system.	Cost Causative	Electric Distribution Plant	Distribution Electric Supervision & Engineering (S&E) FERC 580 using the electric distribution plant to allocate the costs is reasonable because there is a cost causative relationship with the operations supported by electric distribution.	34.8209%
200117	453	Distribution Electric Metering FERC 586	Distribution Electric Metering FERC 586 services include labor, materials used, and expenses incurred in the operation of customer meters and associated equipment (e.g. electric distribution meters standards and development, meter purchases, etc.	Cost Causative	Electric Distribution Plant	Distribution Electric Metering FERC 586 using electric distribution plant to allocate meter costs is reasonable because there is a cost causative relationship with the electric distribution plant and meter operations supported by electric distribution.	34.8209%
200118	527	Distribution Electric Load Dispatching/EMS FERC 581	Distribution Electric Load Dispatching/EMS FERC 581 services include labor, materials used, and expenses incurred in load dispatching operations pertaining to the distribution of electricity. This includes Energy Management Systems (EMS) which provides supervisory control and data acquisition (SCADA) of substation devices through Remote Terminal Units (RTU's).	Cost Causative	Electric Distribution Plant	Distribution Electric Load Dispatching/EMS FERC 581 using electric distribution plant to allocate costs is reasonable because there is a cost causative relationship with the operations supported by load dispatching/EMS-distribution.	34.8209%
200119	506; 507; 559	Distribution Electric & Gas Miscellaneous FERC 588 & 880	Distribution Electric & Gas Miscellaneous FERC 588 & 880 services include labor, materials used, and expenses incurred in distribution system operation not provided for elsewhere. This includes software system labor and non-labor costs for the maintenance that support the electric and gas distribution to our customers as well as non-capital engineering & supervision costs.	Cost Causative	Electric Distribution Plant/ Gas Distribution Plant	Distribution Electric & Gas Miscellaneous FERC 588 & 880 using a ratio of electric distribution plant/gas distribution plant to allocate costs is reasonable because there is a cost causative relationship between the work performed by operations and distribution plant.	32.6107%
200120		Distribution & Transmission Gas Miscellaneous FERC 859 & 880	Distribution & Transmission Gas Miscellaneous FERC 859 & 880 include the cost of labor, materials used, and expenses incurred in providing Gas Emergency Response (GER) activities for the gas distribution and transmission systems as well as other activities related to the gas distribution and transmission systems. Additionally, costs include the labor and non-labor costs for the application development and maintenance of the GER system.	Cost Causative	Gas Distribution Plant/Gas Transmission Plant	Distribution & Transmission Gas Miscellaneous FERC 588 & 880 using a ratio of gas distribution plant/gas transmission plant to allocate costs is reasonable because the costs are directly related to miscellaneous activities, including Gas Emergency Response work for the gas distribution and gas transmission systems.	23.2473%
200121	474	Distribution Electric & Gas and Transmission Gas Miscellaneous FERC 588, 880, & 859	Distribution Electric & Gas and Transmission Gas Miscellaneous FERC 588, 880, & 859 services include gas distribution, gas transmission, and electric distribution labor and non-labor costs associated with accounting, budgeting, and regulatory reporting.	Cost Causative	Electric Distribution Plant/ Gas Transmission Plant/ Gas Distribution Plant	Distribution Electric & Gas and Transmission Gas Miscellaneous FERC 588, 880, & 859 charges that cannot be directly charged to a specific business unit and are corporate in nature. Using a ratio of electric distribution plant/gas transmission plant/gas distribution plant to allocate Utility Group costs is reasonable because there is a cost causative relationship with operations supported by Utilities Group.	30.9774%
200122	442	Transmission Electric Supervision & Engineering (S&E) FERC 560	Transmission Electric Supervision & Engineering (S&E) FERC 560 services include labor and expenses incurred in the general supervision and direction of the operation of the electric transmission system as a whole.	Cost Causative	Electric Transmission Plant	Transmission Electric Supervision & Engineering (S&E) FERC 560 using electric transmission plant to allocate costs is reasonable because there is a cost causative relationship with the operations supported by transmission electric.	32.7858%
200123	451	Transmission Electric Reliability, Planning, & Standards Development FERC 561.5	Transmission Electric FERC 561.5 services include labor, materials used, and expenses incurred for the system planning of the interconnected bulk electric transmission systems within a planning authority area. Activities include transmission reliability, planning and standards development related to transmission assets and reliability needs and transmission customers' requirements and requests (e.g. developing and maintaining transmission system models, applying methodologies and tools for analysis and simulation of systems, notification of any planned transmission changes and impacts, etc.).	Cost Causative	Electric Transmission Plant	Transmission Electric Reliability, Planning, & Standards Development FERC 561.5 using electric transmission plant to allocate costs is reasonable because there is a cost causative relationship with the operations supported by transmission electric.	32.7858%
200124	526	Transmission Electric Load Dispatch-Monitor and Operate Transmission System FERC 561.2	Transmission Electric Load Dispatch-Monitor and Operate Transmission System FERC 561.2 services include labor, materials used, and expenses incurred to monitor, assess and operate the power system and individual transmission facilities in real-time to maintain safe and reliable operation of the transmission system. This also includes the expense incurred to manage transmission facilities to maintain system reliability and to monitor the real-time flows and direct actions according to regional plans and tariffs as necessary.	Cost Causative	Electric Transmission Plant	Transmission Electric Load Dispatch-Monitor and Operate Transmission System FERC 561.2 using electric transmission plant to allocate costs is reasonable because there is a direct causal relationship with the operations supported by EMS-transmission.	32.7858%

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200125	449	Transmission Electric Supervision & Engineering (S&E) NSPM & NSPW FERC 560	Transmission Electric Supervision & Engineering (S&E) NSPM & NSPW FERC 560 services include labor and expenses incurred in the general supervision and direction of the operation of the electric transmission system as a whole. This allocation is used when NSPM and NSPW are the only jurisdictions benefiting from the services.	Cost Causative	Electric Transmission Plant	Transmission Electric Supervision & Engineering (S&E) NSPM & NSPW FERC 560 using electric transmission plant to allocate costs is reasonable because there is a direct causal relationship with the operations supported by transmission electric.	73.5882%
200126	423; 440; 525	Utilities Group Administrative & General (A&G) FERC 921	Utilities Group Administrative & General (A&G) FERC 921 services includes the labor and non-labor costs for utilities group leadership, management and support services for the Distribution, Transmission, transportation and supply chain areas.	Cost Causative	Electric Transmission Plant/ Electric Distribution Plant/ Gas Transmission Plant/Gas Distribution Plant	Utilities Group Administrative & General (A&G) FERC 921 using delivery gross plant to allocate costs is reasonable because these costs are directly related to the electric and gas delivery systems.	31.6613%
200127	443	Distribution Gas Supervision & Engineering (S&E) FERC 870	Distribution Gas Supervision & Engineering (S&E) FERC 870 services include labor and expenses incurred in the general supervision and direction of gas distribution system operations.	Cost Causative	Gas Distribution Plant	Distribution Gas Supervision & Engineering (S&E) FERC 870 using gas distribution plant to allocate costs is reasonable because there is a cost causative relationship with the operations supported by distribution gas.	27.0124%
200128	445	Distribution Gas Miscellaneous FERC 880	Distribution Gas Miscellaneous FERC 880 services include the cost of distribution maps and records, distribution office expenses, and the cost of miscellaneous labor and materials used, and expenses incurred in gas distribution systems. Additionally, the labor and non-labor costs for non-capital engineering and supervision.	Cost Causative	Gas Distribution Plant	Distribution Gas Miscellaneous FERC 880 using gas distribution plant to allocate costs is reasonable because there is a cost causative relationship with the operations supported by Distribution Gas.	27.0124%
200129	454	Distribution Gas Meters and House Regulators FERC 878	Distribution Gas Meters and House Regulators FERC 878 services include the cost of labor, materials used and expenses incurred in connection with removing, resetting, changing, testing, and servicing customer meters and house regulators.	Cost Causative	Gas Distribution Plant	Distribution Gas Meters and House Regulators FERC 878 using gas distribution plant to allocate meter costs is reasonable because there is a cost causative relationship with the gas distribution plant and meter operations supported by gas distribution.	27.0124%
200130	444	Transmission Gas Supervision & Engineering (S&E) FERC 850	Transmission Gas Supervision & Engineering (S&E) FERC 850 services include the cost of labor and expenses incurred in the general supervision and direction of the operation of transmission facilities.	Cost Causative	Gas Transmission Plant	Transmission Gas Supervision & Engineering (S&E) FERC 850 using gas transmission plant to allocate costs is reasonable because there is a cost causative relationship with the operations supported by transmission gas.	8.7347%
200131	531	Distribution & Transmission Gas System Control and Load Dispatching FERC 851 & 871	Distribution & Transmission Gas System Control and Load Dispatching FERC 851 & 871 include the cost of labor, materials used, and expenses incurred in dispatching and controlling the supply and flow of gas through the gas distribution and transmission systems. Additionally, costs include the labor and non-labor costs for the application development and maintenance of the Gas SCADA system.	Cost Causative	Gas Transmission Plant/ Gas Distribution Plant	Distribution & Transmission Gas System Control and Load Dispatching FERC 851 & 871 using a ratio of gas transmission plant/gas distribution plant to allocate costs is reasonable because the costs are directly related to the monitoring of gas distribution and transmission.	23.2473%
200132	413	Payment & Reporting	Payment & Reporting services includes the labor and non-labor costs associated with processing payments to vendors, providing audit research and reconciliation support for Accounts Payable transactions, preparing statistical and 1099 reporting, and administering the purchase card programs.	Cost Causative	Invoice Transactions	Payment & Reporting using invoice transactions to allocate costs is reasonable because the costs are directly related to invoices processed.	26.4351%
200133	128	Proprietary Trading - Back Office	Proprietary Trading - Back Office includes the labor and non-labor costs associated with the accounting support and vice president oversight of proprietary trading activities. This allocator should be primarily used by Accounting and Finance, or others providing Administrative & General (A&G) activities when the trading deal doesn't involve Xcel Energy Utility generating resources, which is also considered non-asset-based trading activity.	Cost Causative	Joint Operating Agreement Peak Hour Megawatt Load Ratio	Proprietary Trading - Back Office uses the Joint Operating Agreement Peak Hour Megawatt Load Ratio for cost allocations as it is required for the Proprietary Trading services under the JOA.	36.5625%
200134	144	Proprietary Trading - Front/Mid Office FERC 557	Proprietary Trading - Front/Mid Office FERC 557 includes the labor and non-labor costs associated with proprietary trading activities which are short term transactions undertaken in the wholesale electric markets where electricity is purchased for the purpose of selling it. Also included are supporting activities: evaluating the credit worthiness of counterparties, reviewing contracts to ensure that regulations are being complied with, evaluating profitability and appropriateness of trades to ensure they are in the best interest of shareholders and rate payers, and ensuring that trades identified as proprietary appropriately fall into that category.	General Allocator	Joint Operating Agreement Peak Hour Megawatt Load Ratio	Proprietary Trading - Front/Mid Office FERC 557 uses the Joint Operating Agreement Peak Hour Megawatt Load Ratio for cost allocations as it is required for the Proprietary Trading services under the JOA.	43.8925%
200135	414	Energy Supply Business Resources	Energy Supply Business Resources services includes the labor and non-labor costs of performance analysis, specialists and analytical services provided to the operating companies' generation facilities.	Cost Causative	MWH Generation	Energy Supply Business Resources using MWH generation to allocate costs is reasonable because the costs are directly related to the support of electric generation facilities.	35.3947%
200136	415	Energy Markets - Fuel	Energy Markets - Fuel includes the labor and non-labor costs for planning and implementing power supply portfolios to provide reliable service to native load and to capitalize on market opportunities including purchasing fuel for the operating companies' electric generation system (excluding nuclear) and resource planning and acquisition including purchase power and account management.	Cost Causative	MWH Generation	Energy Markets - Fuel using MWH generation to allocate costs is reasonable because the costs are directly related to the purchase of fuel for generation.	35.3947%
200137	455	Energy Supply Miscellaneous Power Expense FERC 506, 539, & 549	Energy Supply Miscellaneous Power Expense FERC 506, 539, & 549 services include Energy Supply operations performance services labor and non-labor costs for non-management employees with the following accountabilities: Develop / suggest / implement improvements for multiple power plants, standardize best practices and process improvements across multiple power plants, establish operations and maintenance policies and procedures for multiple power plants.	Cost Causative	MWH Generation	Energy Supply Miscellaneous Power Expense FERC 506, 539, & 549 using MWH generation to allocate costs is reasonable because the costs are directly related to the support of electric generation facilities.	35.3947%
200138	458	Energy Supply Operation Supervision & Engineering (S&E) FERC 500, 535, & 546	Energy Supply Operation Supervision & Engineering (S&E) FERC 500, 535, & 546 services include labor and expenses incurred in the general supervision and direction of the operation of steam powered generation stations, hydraulic power generating stations, and other power generating stations.	Cost Causative	MWH Generation	Energy Supply Operation Supervision & Engineering (S&E) FERC 500, 535, & 546 using MWH generation to allocate costs is reasonable because the costs are directly related to the support of electric generation facilities.	35.3947%

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SAP Cost Center	JDE Work Order No.	Cost Center Description	Description of Services Provided	General Allocator/ Cost Causative	Allocation Method	Reasonableness of Allocation Method	NSPM Alloc Percent FTE Hours
200139	461	Energy Supply Maintenance Supervision & Engineering (S&E) FERC 510, 541, & 551	Energy Supply Maintenance Supervision & Engineering (S&E) FERC 510, 541, & 551 services which include management and performance labor and non-labor costs for the following accountabilities: Researching, reviewing, recommending and facilitating the selection of technological alternatives for improved plant and environmental performance. Manage uniform project management process (policies). Planning for physical plant modifications, which includes consolidation and management of short-term and long-term plans for physical plant modifications. Develop and execute innovative technology projects such as: biomass, solar, wind. Implement enterprise project management (EPM) and planning tools. Establish uniform technology, design & equipment standards.	Cost Causative	MWH Generation	Energy Supply Maintenance Supervision & Engineering (S&E) FERC 510, 541, & 551 using MWH generation to allocate costs is reasonable because the costs are directly related to the support of electric generation facilities.	35.3947%
200143	456	Energy Supply Miscellaneous Power Expense NSPM & NSPW FERC 506, 539, & 549	Energy Supply Miscellaneous Power Expense NSPM & NSPW FERC 506, 539, & 549 services include Energy Supply operations performance services labor and non-labor costs for non-management employees with the following accountabilities: Develop / suggest / implement improvements for multiple power plants, standardize best practices and process improvements across multiple power plants, establish operations and maintenance policies and procedures for multiple power plants. This allocation is used when NSPM & NSPW jurisdictions are benefiting from the services.	Cost Causative	MWH Generation	Energy Supply Miscellaneous Power Expense NSPM & NSPW FERC 506, 539, & 549 using MWH generation to allocate costs is reasonable because the costs are directly related to the support of electric generation facilities.	93.8813%
200144	459	Energy Supply Operation Supervision & Engineering (S&E) NSPM & NSPW FERC 500, 535, & 546	Energy Supply Operation Supervision & Engineering (S&E) NSPM & NSPW FERC 500, 535, & 546 services include labor and expenses incurred in the general supervision and direction of the operation of steam powered generation stations, hydraulic power generating stations, and other power generating stations. This allocation is used when NSPM & NSPW jurisdictions are benefiting from the services.	Cost Causative	MWH Generation	Energy Supply Operation Supervision & Engineering (S&E) NSPM & NSPW FERC 500, 535, & 546 using MWH generation to allocate costs is reasonable because the costs are directly related to the support of electric generation facilities.	93.8813%
200145	462	Energy Supply Maintenance Supervision & Engineering (S&E) NSPM & NSPW FERC 510, 541, & 551	Energy Supply Maintenance Supervision & Engineering (S&E) NSPM & NSPW FERC 510, 541, & 551 services which include management and performance labor and non-labor costs for the following accountabilities: Researching, reviewing, recommending and facilitating the selection of technological alternatives for improved plant and environmental performance. Manage uniform project management process (policies). Planning for physical plant modifications, which includes consolidation and management of short-term and long-term plans for physical plant modifications. Develop and execute innovative technology projects such as: biomass, solar, wind. Implement enterprise project management (EPM) and planning tools. Establish uniform technology, design & equipment standards. This allocation is used when NSPM & NSPW jurisdictions are benefiting from the services.	Cost Causative	MWH Generation	Energy Supply Maintenance Supervision & Engineering (S&E) NSPM & NSPW FERC 510, 541, & 551 using MWH generation to allocate costs is reasonable because the costs are directly related to the support of electric generation facilities.	93.8813%
200146	429	Energy Markets - Regulated Trading	Energy Markets - Regulated Trading services include the labor and non-labor costs of providing electric trading services to the operating companies' electric generation systems, including load management, system optimization and origination.	Cost Causative	MWH Hours Sold	Energy Markets - Regulated Trading using MWH hours sold to allocate costs is reasonable because there is a cost causative relationship between regulated trading activities and the MWH hours sold.	35.7964%
200147	554	Business Objects	Business Objects includes the labor and non-labor costs for the application that provides critical reporting from data universes and tables.	Cost Causative	No. of Business Objects Users	Business Objects using No. of Business Object users to allocate costs is reasonable because the costs are directly related to users who can access the application.	50.0218%
200148	500; 524	Business Systems	Business Systems services includes the costs of providing assistance to computer users across the company. Specifically computer technology risk, software maintenance on applications Distributed to all users (e.g. Microsoft PC tools), governance and project management over all IT projects, fixed management fees with outside vendors, business analytics costs, corrective and preventative maintenance, security, data backup and recovery, help desk, and amortization of outside vendor fees and costs that are not specific to an application that has a specific allocator.	Cost Causative	No. of Computers	Business Systems using No. of computers to allocate costs is reasonable because there is a cost causative relationship between the No. of computers and the cost to support them.	49.1506%
200149	534	Customer & Enterprise Solutions (CES)	Customer & Enterprise Solutions (CES) includes the labor and non-labor costs for the leadership of the Customer & Enterprise Solutions organization and their administrative support staff.	Cost Causative	No. of Computers/ No. of Customers/ FTE Hours	Customer & Enterprise Solutions (CES) using a ratio of No. of Computers/Customers/Employees to allocate costs is reasonable because there is a cost causative relationship with the operations supported by CES.	43.8591%
200150	520	Interactive Voice Response (IVR)	Interactive Voice Response (IVR) includes the labor and non-labor costs for the application development and maintenance of the Interactive Voice Response system which interacts with a customer calling Xcel Energy call centers. It is intended to help service customers without invoking a call center agent. If the call needs to be handled by an agent, account information and the reason for the call is determined which helps route the call to the appropriate agent.	Cost Causative	No. of Contacts	Interactive Voice Response (IVR) using No. of contacts to allocate costs is reasonable because this system is used to take and route customer calls and benefits customers using the call centers.	34.0532%
200151	447	Customer Billing FERC 903	Customer Billing FERC 903 includes the labor and non-labor costs related to the delivery of billing statements, letters and notices to Xcel customers including postage and outside services costs, oversight and administration of customer billing area, research of billing exceptions, providing escalated customer service assistance with regard to billing issues resolution, and process remittances and receivables. This allocation is used when all four jurisdictions are benefiting from the services.	Cost Causative	No. of Customer Bills	Customer Billing FERC 903 using No. of customer bills to allocate costs is reasonable because the costs are directly related to customer billing activities.	39.0927%
200152	436	Customer Care FERC 902	Customer Care FERC 902 services includes the labor and non-labor costs for meter reading of retail and wholesale customers and determining consumption for billing purposes as well as executing field collections.	Cost Causative	No. of Customers	Customer Care FERC 902 using No. of customers to allocate costs is reasonable because the costs are directly related to customers.	38.2987%
200153	185	Customer Safety Advertising & Information Costs	Customer Safety Advertising & Information costs services includes the labor and non-labor costs associated with public safety advertising, information and education.	Cost Causative	No. of Customers	Customer Safety Advertising & Information Costs using No. of customers to allocate costs is reasonable because the costs are directly related to customers.	38.3714%

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SAP Cost Center	JDE Work Order No.	Cost Center Description	Description of Services Provided	General Allocator/ Cost Causative	Allocation Method	Reasonableness of Allocation Method	NSPM Alloc Percent FTE Hours
200154	403	Customer Service Information Technology (IT) FERC 903	Customer Service Information Technology (IT) FERC 903 services includes the labor and non-labor costs for IT applications related customer billing to customers, call center support and credit and collections.	Cost Causative	No. of Customers	Customer Service Information Technology (IT) FERC 903 using No. of customers to allocate costs is reasonable because the costs are directly related to customers.	38.3714%
200155	435	Customer Care FERC 903	Customer Care FERC 903 services includes the labor and non-labor costs for contact centers, remittance processing, credit and collections, customer resource management, and contact center training. This allocation is used when all four jurisdictions are benefiting from the services such as responding to residential customer inquiries regarding billings and outages, handling inbound credit calls, outbound collections calls, managing accounts receivables, training call center staffs, developing contact center call forecasts.	Cost Causative	No. of Customers	Customer Care FERC 903 using No. of customers to allocate costs is reasonable because the costs are directly related to customers.	38.3714%
200156	437	Customer Care FERC 901	Customer Care FERC 901 services includes the labor and non-labor costs for the leadership of the customer care organization and their administrative support staff such as consulting costs to support overall Customer Care organizational operations.	Cost Causative	No. of Customers	Customer Care FERC 901 using No. of customers to costs is reasonable because the costs are directly related to customers.	38.3714%
200159	405	Customer Service Information Technology (IT) NSPM & NSPW FERC 903	Customer Service Information Technology (IT) NSPM & NSPW FERC 903 services includes the labor and non-labor costs for IT applications related customer billing to customers, call center support and credit and collections. This allocation is used when NSPM & NSPW jurisdictions are benefiting from the services.	Cost Causative	No. of Customers	Customer Service Information Technology (IT) NSPM & NSPW FERC 903 using No. of customers to allocate costs is reasonable because the costs are directly related to customers.	85.1316%
200160	439	Customer Care NSPM & NSPW FERC 903	Customer Care NSPM & NSPW FERC 903 services includes the labor and non-labor costs for contact centers, and credit and collections, such as responding to commercial customers inquiries at the Business Solution Center. This is primarily used by the Customer Care organization when NSPM and NSPW jurisdictions are benefiting from the services.	Cost Causative	No. of Customers	Customer Care NSPM & NSPW FERC 903 using No. of customers to allocate costs is reasonable because the costs are directly related to customers.	85.1316%
200161	446	Customer Care Low Income Assistance FERC 908	Customer Care Low Income Assistance FERC 908 services includes the labor and non-labor costs associated with the low income energy customer program such as answering calls from customers for referral to low income assistance agencies, providing information to the agencies in order to process applications for assistance, take pledges/commitments from agencies and process payments from agencies.	Cost Causative	No. of Residential Customers	Customer Care Low Income Assistance FERC 908 using No. of residential customers to allocate costs is reasonable because the costs are directly related to customers.	42.7675%
200162	519	Call Logging and Quality Management (CL/QM) FERC 903	Call Logging and Quality Management (CL/QM) FERC 903 includes the labor and non-labor operating costs for the application development and maintenance of the Call Logging and Quality Management system which is used to monitor and record calls for contact center training and leadership teams.	Cost Causative	No. of Customers/ No. of Contacts	Call Logging and Quality Management (CL/QM) FERC 903 using a ratio of no. of customers/no. of contacts to allocated costs is reasonable because the system benefits current and potential customers using the call centers.	36.2123%
200163	181	Employee Communications	Employee Communications includes the labor and non-labor costs for the development and enhancement of employee awareness and understanding of the company's strategies, priorities, decisions and performance objectives. It develops and produces regular communication vehicles, including TODAY (daily news bulleting on intranet); XTRA (monthly print publication for all employees and retirees); All Managers E-mail (real-time communication for employees who supervise and manage others); Focus on Financials for all employees; targeted communications for specific business areas, such as Human Resources, and employee meetings.	Cost Causative	FTE Hours	Employee Communications using FTE Hours to allocate costs is reasonable because the costs are directly related to employees.	44.0539%
200164	198	Payroll	Payroll services include the labor and non-labor costs for processing payroll including consolidation of time collection, calculation of salaries and wages, administration of employee deductions, account Distribution and reconciliation, allocation and accounting for employment taxes and compliance reports.	Cost Causative	FTE Hours	Payroll using FTE Hours to allocate costs is reasonable because the costs are directly related to employees.	44.0539%
200165	515; 521; 552	Employee Management Systems	Employee Management Systems includes the labor and non-labor costs for the Security Operations Center (SOC), Time capture and processing for payroll and accounting and Human Resources software. These applications and services provide services for the whole company related to enterprise security, including physical access, security monitoring and investigations, payroll and time accounting and employee information databases.	Cost Causative	FTE Hours	Employee Management Systems using FTE Hours to allocate costs is reasonable because the costs are directly related to employees.	44.0539%
200166	190; 197; 199	Human Resources (Diversity/Safety/Employee Relations)	Human Resources (Diversity/Safety/Employee Relations) includes the labor and non-labor costs for work performed for operating and affiliate company employees, such as diversity programs, providing workforce relations resources for labor agreements, arbitration, and training. Manage, design, and implement Corporate Safety initiatives. Staffing administration for non-bargaining positions and provides Affirmative Action plans (development) and government audit management (compliance).	Cost Causative	FTE Hours	Human Resources (Diversity/Safety/Emp Relations) using FTE Hours to allocate Human Resources costs is reasonable because the costs are directly related to employees.	44.0553%
200167	508; 550	e-Business	The e-Business system includes the labor and non-labor costs associated with the corporate electronic business infrastructure.	Cost Causative	FTE Hours	e-Business using FTE Hours to allocate costs is reasonable because the costs benefit employees.	44.0553%
200168	517	Gas Management System (GMS) FERC 866 & 880	Gas Management System (GMS) FERC 866 & 880 supports Xcel Energy gas transportation business including contracts, nominations/allocations, end-user measurement, imbalance management, and input for billing. also supports gas system supply, other balancing services. Costs include labor and non-labor for the application development and maintenance of the Gas Management System.	Cost Causative	No. of Gas Customers	Gas Management System (GMS) FERC 866 & 880 using No. of gas customers to allocate costs is reasonable because this system benefits gas customers.	0.0017%

XES Allocation Descriptions, Methods and NSPM Percentages (Using Allocated FTE Hours)

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SAP Cost Center	JDE Work Order No.	Cost Center Description	Description of Services Provided	General Allocator/ Cost Causative	Allocation Method	Reasonableness of Allocation Method	NSPM Alloc Percent FTE Hours
200169	504; 537; 553	Energy Supply Systems Miscellaneous FERC 417.1, 506, 539, & 549	Energy Supply Systems Miscellaneous FERC 417.1, 506, 539, & 549 includes the labor and non-labor costs for the non-critical applications that support the Energy Supply area. Such as Emissions Tracker, Labworks, SAP WAM, Documentum and Meridian.	Cost Causative	No. of WAM ES Users	Energy Supply Systems Miscellaneous FERC 417.1, 506, 539, & 549 using the no. of WAM ES users to allocate the costs is reasonable because there is a direct causal relationship with the operations supported by WAM ES.	36.4855%
200170	518; 540	Meter Reading and Monitoring Systems FERC 902	Meter Reading and Monitoring Systems FERC 902 includes the labor and non-labor operating costs for the application development and maintenance of the software applications needed to read and monitor gas and electric meters, including Meter Data Lake.	Cost Causative	No. of Meters	Meter Reading and Monitoring Systems FERC 902 using No. of meters to allocate costs is reasonable because there is a direct causal relationship with the companies use of systems to monitor meters.	35.5498%
200171	503; 555	Customer Resource System (CRS) FERC 903	Customer Resource System (CRS) FERC 903 includes the labor and non-labor costs for the CRS system, specifically, application development and maintenance costs, licensing fees, server system costs and technology risk costs specific to disaster recovery of this application. CRS is Xcel Energy's customer service and billing system.	Cost Causative	No. of Meters/ No. of Contacts	Customer Resource System (CRS) FERC 903 using a ratio of no. of meters/no. of contacts to allocate costs is reasonable because there is a direct causal relationship with the operations supported by CRS.	34.8015%
200172	523	Network	Network services include the labor and non-labor costs for the operation, maintenance, and management of Xcel Energy's internal and external Information Technology Network. This includes circuits, firewalls and communication assets.	Cost Causative	Phones/ Radios/ Computers	Network using a ratio of phones/radios/computers to allocate costs is reasonable because the network supports these major items.	50.2755%
200173	129	Generation Trading/Native Hedge - Back Office	Generation Trading/Native Hedge - Back Office includes the labor and non-labor costs associated with oversight and administration of accounting related trading costs including generation trading and native hedge. This allocator should be primarily used by Accounting and Finance, or others providing Administrative & General (A&G) activities when energy trades are executed using one of Xcel Energy Utilities generation resources.	Cost Causative	Joint Operating Agreement Labor Hours Ratio	Gen/Prop Trading - Back Office use of Joint Operating Agreement Labor Hours Ratio is reasonable because there is a direct correlation between the front office activities and the mid-office and back-office activities. It is required to use the Joint Operating Agreement for the Proprietary split for these accounting and trading costs.	31.5833%
200174	145	Generation Trading/Native Hedge - Mid Office FERC 557	Generation Trading/Native Hedge - Mid Office FERC 557 includes the labor and non-labor costs associated with independent evaluation and risk measurement of trading and generation book transactions, including preparing daily P&L (profit and loss) reports and individual trader profit and loss reports for the prop book, daily generation book valuation reports for each system showing all net fuel positions and any forward sales values and/or hedges, ensuring that margin reporting follows all SEC rules and GAAP reporting and that credit and risk policies and procedures are complied with.	Cost Causative	Joint Operating Agreement Labor Hours Ratio	Gen/Prop Trading - Mid Office FERC 557 use of Joint Operating Agreement Labor Hours Ratio is reasonable because there is a direct correlation between the front office activities and the mid-office and back-office activities. It is required to use the Joint Operating Agreement for the Proprietary split for these accounting and trading costs.	37.9151%
200176	412	Marketing & Sales	Marketing & Sales services includes the labor and non-labor costs for marketing and sales services for the operating companies for their customers including strategic planning, segment identification, business analysis, sales planning, customer service, promoting products to the business market, and providing regulatory and policy support with respect to utility energy efficiency and demand response program design, evaluation, measurement and verification, cost effectiveness testing , and cost recovery.	Cost Causative	Revenue	Marketing & Sales using revenue to allocate costs is reasonable because Marketing & Sales support the revenue-producing operations of the company.	42.2185%
200177	418	Rates & Regulation - Electric	Rates & Regulation - Electric includes the labor and non-labor costs for determining the regulated utilities' electric utility revenue requirements and rates for electric customers regulatory strategy, coordinating the regulatory compliance requirements, establishing and maintaining relationships with regulatory bodies, policy development of regulatory and legislative strategy, preparing and organizing rate case filings.	Cost Causative	Revenue	Rates & Regulation Electric using revenue to allocate costs is reasonable because they are responsible for setting revenue requirements.	31.3292%
200178	417	Rates & Regulation	Rates & Regulation includes the labor and non-labor costs for determining the regulated utilities' revenue requirements and rates for electric and gas customers regulatory strategy, coordinating the regulatory compliance requirements, establishing and maintaining relationships with regulatory bodies, policy development of regulatory and legislative strategy, preparing and organizing rate case filings.	Cost Causative	Revenue	Rates & Regulation using revenue to allocate costs is reasonable because they are responsible for setting revenue requirements.	31.3292%
200180	528	EMS-Shared (Energy Management System-SCADA) FERC 556, 561.2, & 581	EMS-Shared (Energy Management System-SCADA) FERC 556, 561.2, & 581 provides supervisory control and data acquisition of substation devices through Remote Terminal Units (RTU's). EMS-Shared system includes the labor and non-labor costs for the application development and maintenance of the Electric Transmission, Distribution and Production Plant information operations.	Cost Causative	Electric Production Plant/ Electric Transmission Plant/ Electric Distribution Plant	EMS-Shared (Energy Management System-SCADA) FERC 556, 561.2, & 581 using a ratio of electric production plant/electric transmission plant/electric distribution plant to allocate costs is reasonable because there is a direct causal relationship with the operations supported by EMS-Shared.	41.1404%
200181	464	Energy Supply Environmental Policy & Services	Energy Supply Environmental Policy & Services include the labor and non-labor costs dedicated to air quality, renewable energy, innovative technology and climate change, develop corporate compliance strategy, regulatory agency interaction (both at the federal and/or state level), permitting and compliance reporting, waste management, combustion byproducts management, environmental compliance auditing, provide support to the Environmental Council and assist with environmental communications strategies.	Cost Causative	Electric Production Plant/ Electric Transmission Plant/ Electric Distribution Plant/ Gas Transmission Plant/ Gas Distribution Plant	Energy Supply Environmental Policy & Services using gross plant assets to allocate costs is reasonable because the costs are directly related to the environmental policies and services which are generated by the operation and ownership of the assets.	38.9619%

XES Allocation Descriptions, Methods and NSPM Percentages (Using Allocated FTE Hours)

2022 Test Year Budget

SAP Cost Center	JDE Work Order No.	Cost Center Description	Description of Services Provided	General Allocator/ Cost Causative	Allocation Method	Reasonableness of Allocation Method	NSPM Alloc Percent FTE Hours
200182	465	Energy Supply Environmental Policy & Services NSPM & NSPW	ES Environmental Policy & Services NSPM & NSPW functions which include the labor and non-labor costs dedicated to air quality, renewable energy, innovative technology and climate change, develop corporate compliance strategy, regulatory agency interaction (both at the federal and/or state level), permitting and compliance reporting, waste management, combustion byproducts management, environmental compliance auditing, provide support to the Environmental Council and assist with environmental communications strategies. This allocation is used when NSPM and NSPW jurisdictions are benefiting from the services.	Cost Causative	Electric Production Plant/ Electric Transmission Plant/ Electric Distribution Plant/ Gas Transmission Plant/ Gas Distribution Plant	ES Environmental Policy & Services NSPM & NSPW using gross plant assets to allocate costs is reasonable because the costs are directly related to the environmental policies and services which are generated by the operation and ownership of the assets.	86.0579%
200184	516	PowerPlan	PowerPlan includes the labor and non-labor operating costs for PowerPlan, which is the capital asset business system which includes the following modules. Fixed Assets, Power Tax, Property Tax, Projects, Budgets, Cost Repository, Depreciation studies and Depreciation forecast. This includes the application development and maintenance costs, licensing fees, server system costs and technology risk costs specific to disaster recovery of this application.	Cost Causative	Total Plant	PowerPlan using total plant to allocate costs is reasonable because there is a direct causal relationship with the companies using PowerPlan to manage plant assets.	41.6215%
200805		HomeSmart Revenue – Non-Utility 417.1	HomeSmart Revenue – Non-Utility 417,1 includes the labor and non-labor costs, including but not limited to business administration, advertising, marketing, software and technology costs related to all HomeSmart activity (Equipment Sales, Service Plan, and Service Call) across MN & CO Jurisdictions.	Cost Causative	Revenues	HomeSmart Revenue – Non-Utility 417,1 to allocate costs is reasonable because the costs are directly related to revenue generating activities of the business activity.	72.4224%
200806		HomeSmart Customers – Non-Utility 417.1	HomeSmart Customers – Non-Utility 417.1 includes the labor and non-labor costs, including but not limited to business administration, advertising, marketing, software and technology costs related to HomeSmart Service Plan activity across MN & CO Jurisdictions.	Cost Causative	No. of Customers	HomeSmart Customers – Non-Utility 417.1 to allocate costs is reasonable because the costs are directly related to customer related activities of the business activity.	72.3632%

XES Allocation Statistics
2022 Test Year Budget

Allocating Cost Center	Allocating Cost Center Description	Method of Allocation	Percentage	Allocation Statistics									
200063	Executive - Corporate Governance	Asset/Revenue/Number of Employees	38.9021%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM No. of Employees - 3,785	Total No. of Employees - 7,801				
200064	Shareholder - Corporate Governance	Asset/Revenue/Number of Employees	38.9021%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM No. of Employees - 3,785	Total No. of Employees - 7,801				
200065	Investor Relations - Corporate Governance	Asset/Revenue/Number of Employees	38.9021%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM No. of Employees - 3,785	Total No. of Employees - 7,801				
200066	Accounting, Reporting & Tax - Corporate Governance	Asset/Revenue/Number of Employees	38.9021%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM No. of Employees - 3,785	Total No. of Employees - 7,801				
200067	Audit Services - Corporate Governance	Asset/Revenue/Number of Employees	38.9021%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM No. of Employees - 3,785	Total No. of Employees - 7,801				
200068	Corporate Finance, Treasury & Cash Management - Corporate Governance	Asset/Revenue/Number of Employees	38.9021%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM No. of Employees - 3,785	Total No. of Employees - 7,801				
200069	Risk Management - Corporate Governance	Asset/Revenue/Number of Employees	38.9021%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM No. of Employees - 3,785	Total No. of Employees - 7,801				
200070	Corporate Strategy & Business Development - Corporate Governance	Asset/Revenue/Number of Employees	38.9021%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM No. of Employees - 3,785	Total No. of Employees - 7,801				
200071	Legal - Corporate Governance	Asset/Revenue/Number of Employees	38.9021%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM No. of Employees - 3,785	Total No. of Employees - 7,801				
200072	Communications - Corporate Governance	Asset/Revenue/Number of Employees	38.9021%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM No. of Employees - 3,785	Total No. of Employees - 7,801				
200073	Human Resources - Corporate Governance	Asset/Revenue/Number of Employees	38.9021%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM No. of Employees - 3,785	Total No. of Employees - 7,801				
200074	Corporate Systems – Corporate Governance	Asset/Revenue/Number of Employees	38.9021%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM No. of Employees - 3,785	Total No. of Employees - 7,801				
200075	Board of Directors - Corporate Governance	Asset/Revenue/Number of Employees	38.9021%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM No. of Employees - 3,785	Total No. of Employees - 7,801				
200076	Xcel Foundation	Asset/Revenue/Number of Employees	38.9671%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM No. of Employees - 3,785	Total No. of Employees - 7,801				
200077	Branding	Asset/Revenue/Number of Employees	38.9671%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM No. of Employees - 3,785	Total No. of Employees - 7,801				
200078	Governmental Affairs	Asset/Revenue/Number of Employees	38.9904%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM No. of Employees - 3,785	Total No. of Employees - 7,801				
200079	Federal Lobbying	Asset/Revenue/Number of Employees	38.9904%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM No. of Employees - 3,785	Total No. of Employees - 7,801				
200080	Capital Asset Accounting	Asset/Revenue/Number of Employees	44.1421%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM No. of Employees - 3,785	Total No. of Employees - 7,801				
200081	Accounting, Reporting & Taxes	Asset/Revenue/Number of Employees	44.2178%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM No. of Employees - 3,785	Total No. of Employees - 7,801				
200082	Audit Services	Asset/Revenue/Number of Employees	44.2178%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM No. of Employees - 3,785	Total No. of Employees - 7,801				
200083	Corporate Finance, Treasury & Cash Management	Asset/Revenue/Number of Employees	44.2178%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM No. of Employees - 3,785	Total No. of Employees - 7,801				
200084	Risk Management	Asset/Revenue/Number of Employees	44.2178%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM No. of Employees - 3,785	Total No. of Employees - 7,801				
200086	Legal & Claims Services	Asset/Revenue/Number of Employees	44.2178%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM No. of Employees - 3,785	Total No. of Employees - 7,801				
200087	Accounting, Reporting & Tax - Regulated	Asset/Revenue/Number of Employees	44.2290%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM No. of Employees - 3,785	Total No. of Employees - 7,801				
200088	Accounting, Reporting, Tax & Audit Services - Regulated Electric	Asset/Revenue/Number of Employees	44.2290%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM No. of Employees - 3,785	Total No. of Employees - 7,801				
200089	Audit Services - OpCo's & TransCo's	Asset/Revenue/Number of Employees	44.2290%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM No. of Employees - 3,785	Total No. of Employees - 7,801				
200090	Risk Management - OpCo's & TransCo's	Asset/Revenue/Number of Employees	44.2290%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM No. of Employees - 3,785	Total No. of Employees - 7,801				
200091	Captive Insurance	Asset/Revenue/Number of Employees	44.2290%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM No. of Employees - 3,785	Total No. of Employees - 7,801				
200092	Corporate Strategy & Business Development	Asset/Revenue/Number of Employees	44.2290%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM No. of Employees - 3,785	Total No. of Employees - 7,801				
200093	Legal - OpCo's & TransCo's	Asset/Revenue/Number of Employees	44.2290%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM No. of Employees - 3,785	Total No. of Employees - 7,801				
200094	Supply Chain	Asset/Revenue/Number of Employees	44.2290%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM No. of Employees - 3,785	Total No. of Employees - 7,801				
200095	Energy Supply Asset Management	Asset/Revenue/Number of Employees	44.2290%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM No. of Employees - 3,785	Total No. of Employees - 7,801				
200096	Energy Markets - Business Services	Asset/Revenue/Number of Employees	44.2290%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM No. of Employees - 3,785	Total No. of Employees - 7,801				
200097	Accounting and Finance Software Applications Maintenance	Asset/Revenue/Number of Employees	44.2290%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM No. of Employees - 3,785	Total No. of Employees - 7,801				
200098	Electric Transmission FERC 566	Asset/Revenue/Number of Employees	44.2290%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM No. of Employees - 3,785	Total No. of Employees - 7,801				
200099	Electric Distribution FERC 588	Asset/Revenue/Number of Employees	44.2290%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM No. of Employees - 3,785	Total No. of Employees - 7,801				
200100	Accounting, Reporting, Tax & Audit Services – Regulated Gas	Asset/Revenue/Number of Employees	52.1537%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM No. of Employees - 3,785	Total No. of Employees - 7,801				
200101	Legal Gas	Asset/Revenue/Number of Employees	52.1537%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM No. of Employees - 3,785	Total No. of Employees - 7,801				
200102	Gas Distribution FERC 880	Asset/Revenue/Number of Employees	52.1537%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM No. of Employees - 3,785	Total No. of Employees - 7,801				
200105	Accounting & Reporting - NSPM & NSPW	Asset/Revenue/Number of Employees	86.9558%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM No. of Employees - 3,785	Total No. of Employees - 7,801				
200106	Accounting & Reporting Electric - NSPM & NSPW	Asset/Revenue/Number of Employees	86.9558%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM No. of Employees - 3,785	Total No. of Employees - 7,801				
200107	Legal - NSPM & NSPW	Asset/Revenue/Number of Employees	86.9558%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM No. of Employees - 3,785	Total No. of Employees - 7,801				
200108	Advanced Metering Infrastructure (AMI)	No. of AMI Enabled Meters	56.2262%	NSPM No. of AMI Meters - 16,544	Total AMI Meters - 29,424								
200111	Enterprise Application Integration (EAI)	Average of a Select Set of Software Allocators	39.0533%	NSPM Percentage - 39.0666%	Total Percent - 100%								
200112	Mainframe Charges	Average of a Select Set of Software Allocators	28.0236%	NSPM Percentage - 28.0236%	Total Percent - 100%								
200115	Miscellaneous Applications	Average of all Software Percentages	35.5212%	NSPM Percentage - 35.8069%	Total Percent - 100%								
200116	Distribution Electric Supervision & Engineering (S&E) FERC 580	Electric Distribution Plant	34.8209%	NSPM Gross Electric Dist Plant - $4,601,756	Total Gross Electric Dist Plant - $13,215,497								
200117	Distribution Electric Metering FERC 586	Electric Distribution Plant	34.8209%	NSPM Gross Electric Dist Plant - $4,601,756	Total Gross Electric Dist Plant - $13,215,497								
200118	Distribution Electric Load Dispatching/EMS FERC 581	Electric Distribution Plant	34.8209%	NSPM Gross Electric Dist Plant - $4,601,756	Total Gross Electric Dist Plant - $13,215,497								
200119	Distribution Electric & Gas Miscellaneous FERC 588 & 880	Electric Distribution Plant/ Gas Distribution Plant	32.6107%	NSPM Gross Electric Dist Plant - $4,601,756	Total Gross Electric Dist Plant - $13,215,497	NSPM Gross Gas Dist Plant - $1,409,320	NSPM Gross Gas Dist Plant - $5,217,315						
200120	Distribution & Transmission Gas Miscellaneous FERC 859 & 880	Gas Distribution Plant/Gas Transmission Plant	23.2473%	NSPM Gross Electric Dist Plant - $4,601,756	Total Gross Electric Dist Plant - $13,215,497	NSPM Gross Gas Dist Plant - $1,409,320	NSPM Gross Gas Dist Plant - $5,217,315						
200121	Distribution Electric & Gas and Transmission Gas Miscellaneous FERC 588, 880, & 859	Electric Distribution Plant/ Gas Transmission Plant/ Gas Distribution Plant	30.9774%	NSPM Gross Electric Dist Plant - $4,601,756	Total Gross Electric Dist Plant - $13,215,497	NSPM Gross Gas Trans Plant - $118,230	Total Gross Gas Trans Plant - $1,353,562	NSPM Gross Gas Dist Plant - $1,409,320	NSPM Gross Gas Dist Plant - $5,217,315				
200122	Transmission Electric Supervision & Engineering (S&E) FERC 560	Electric Transmission Plant	32.7858%	NSPM Gross Electric Trans Plant - $3,944,789	Total Gross Electric Trans Plant - $12,031,999								
200123	Transmission Electric Reliability, Planning, & Standards Development FERC 561.5	Electric Transmission Plant	32.7858%	NSPM Gross Electric Trans Plant - $3,944,789	Total Gross Electric Trans Plant - $12,031,999								
200124	Transmission Electric Load Dispatch-Monitor and Operate Transmission System FERC 561.2	Electric Transmission Plant	32.7858%	NSPM Gross Electric Trans Plant - $3,944,789	Total Gross Electric Trans Plant - $12,031,999								
200125	Transmission Electric Supervision & Engineering (S&E) NSPM & NSPW FERC 560	Electric Transmission Plant	73.5882%	NSPM Gross Electric Trans Plant - $3,944,789	Total Gross Electric Trans Plant - $12,031,999								

XES Allocation Statistics
2022 Test Year Budget

Allocating Cost Center	Allocating Cost Center Description	Method of Allocation	Percentage	Allocation Statistics									
200126	Utilities Group Administrative & General (A&G) FERC 921	Electric Transmission Plant/ Electric Distribution Plant/ Gas Transmission Plant/Gas Distribution Plant	31.6613%	NSPM Gross Electric Trans Plant - $3,944,789	Total Gross Electric Trans Plant - $12,031,999	NSPM Gross Electric Dist Plant - $4,601,756	Total Gross Electric Dist Plant - $13,215,497	NSPM Gross Gas Trans Plant - $118,230	Total Gross Gas Trans Plant - $1,353,562	NSPM Gross Gas Dist Plant - $1,409,320	NSPM Gross Gas Dist Plant - $5,217,315		
200127	Distribution Gas Supervision & Engineering (S&E) FERC 870	Gas Distribution Plant	27.0124%	NSPM Gross Gas Dist Plant - $1,409,320	NSPM Gross Gas Dist Plant - $5,217,315								
200128	Distribution Gas Miscellaneous FERC 880	Gas Distribution Plant	27.0124%	NSPM Gross Gas Dist Plant - $1,409,320	NSPM Gross Gas Dist Plant - $5,217,315								
200129	Distribution Gas Meters and House Regulators FERC 878	Gas Distribution Plant	27.0124%	NSPM Gross Gas Dist Plant - $1,409,320	NSPM Gross Gas Dist Plant - $5,217,315								
200130	Transmission Gas Supervision & Engineering (S&E) FERC 850	Gas Transmission Plant	8.7347%	NSPM Gross Gas Trans Plant - $118,230	Total Gross Gas Trans Plant - $1,353,562								
200131	Distribution & Transmission Gas System Control and Load Dispatching FERC 851 & 871	Gas Transmission Plant/ Gas Distribution Plant	23.2473%	NSPM Gross Gas Trans Plant - $118,230	Total Gross Gas Trans Plant - $1,353,562	NSPM Gross Gas Dist Plant - $1,409,320	NSPM Gross Gas Dist Plant - $5,217,315						
200132	Payment & Reporting	Invoice Transactions	26.4351%	NSPM Invoice Transactions - 136,897	Total Invoice Transactions - 517,861								
200133	Proprietary Trading - Back Office	Joint Operating Agreement Peak Hour Megawatt Load Ratio	36.5625%	NSPM Peak MWH - 8,570	Total Peak MWH - 19,525								
200134	Proprietary Trading - Front/Mid Office FERC 557	Joint Operating Agreement Peak Hour Megawatt Load Ratio	43.8925%	NSPM Peak MWH - 8,570	Total Peak MWH - 19,525								
200135	Energy Supply Business Resources	MWH Generation (000's)	35.3947%	NSPM MWH Generation - 21,289,608	Total MWH Generation - 60,149,134								
200136	Energy Markets - Fuel	MWH Generation (000's)	35.3947%	NSPM MWH Generation - 21,289,608	Total MWH Generation - 60,149,134								
200137	Energy Supply Miscellaneous Power Expense FERC 506, 539, & 549	MWH Generation (000's)	35.3947%	NSPM MWH Generation - 21,289,608	Total MWH Generation - 60,149,134								
200138	Energy Supply Operation Supervision & Engineering (S&E) FERC 500, 535, & 546	MWH Generation (000's)	35.3947%	NSPM MWH Generation - 21,289,608	Total MWH Generation - 60,149,134								
200139	Energy Supply Maintenance Supervision & Engineering (S&E) FERC 510, 541, & 551	MWH Generation (000's)	35.3947%	NSPM MWH Generation - 21,289,608	Total MWH Generation - 60,149,134								
200143	Energy Supply Miscellaneous Power Expense NSPM & NSPW FERC 506, 539, & 549	MWH Generation (000's)	93.8813%	NSPM MWH Generation - 21,289,608	Total MWH Generation - 60,149,134								
200144	Energy Supply Operation Supervision & Engineering (S&E) NSPM & NSPW FERC 500, 535, & 546	MWH Generation (000's)	93.8813%	NSPM MWH Generation - 21,289,608	Total MWH Generation - 60,149,134								
200145	Energy Supply Maintenance Supervision & Engineering (S&E) NSPM & NSPW FERC 510, 541, & 551	MWH Generation (000's)	93.8813%	NSPM MWH Generation - 21,289,608	Total MWH Generation - 60,149,134								
200146	Energy Markets - Regulated Trading	MWH Hours Sold (000's)	35.7964%	NSPM MWh Hour Sales - 39,627,640	Total MWh Hour Sales - 110,702,985								
200147	Business Objects	Number of Business Objects Users	50.0218%	NSPM No. of Business Objects users - 1,151	Total No. of Business Objects users - 2,301								
200148	Business Systems	Number of Computers	49.1506%	NSPM No. of Computers - 5,526	NSPM No. of Computers - 11,243								
200149	Customer & Enterprise Solutions (CES)	Number of - Computers/Customers/Employees	45.3742%	NSPM No. of Computers - 5,526	NSPM No. of Computers - 11,243	NSPM No. of Customers - 1,643,299	Total No. of Customers - 4,290,744	NSPM No. of Employees - 3,785	Total No. of Employees - 7,801				
200150	Interactive Voice Response (IVR)	Number of Contacts	34.0532%	NSPM No. of Contacts - 1,159,268	Total No. of Contacts - 3,404,285								
200151	Customer Billing FERC 903	Number of Customer Bills	39.0927%	NSPM No. of Customer Bills - 1,525,218	Total No. of Customer Bills - 3,901,545								
200152	Customer Care FERC 902	Number of Customers	38.2987%	NSPM No. of Customers - 1,643,299	Total No. of Customers - 4,290,744								
200153	Customer Safety Advertising & Information Costs	Number of Customers	38.3714%	NSPM No. of Customers - 1,643,299	Total No. of Customers - 4,290,744								
200154	Customer Service Information Technology (IT) FERC 903	Number of Customers	38.3714%	NSPM No. of Customers - 1,643,299	Total No. of Customers - 4,290,744								
200155	Customer Care FERC 903	Number of Customers	38.3714%	NSPM No. of Customers - 1,643,299	Total No. of Customers - 4,290,744								
200156	Customer Care FERC 901	Number of Customers	38.3714%	NSPM No. of Customers - 1,643,299	Total No. of Customers - 4,290,744								
200159	Customer Service Information Technology (IT) NSPM & NSPW FERC 903	Number of Customers	85.1316%	NSPM No. of Customers - 1,643,299	Total No. of Customers - 4,290,744								
200160	Customer Care NSPM & NSPW FERC 903	Number of Customers	85.1316%	NSPM No. of Customers - 1,643,299	Total No. of Customers - 4,290,744								
200161	Customer Care Low Income Assistance FERC 908	No. of Residential Customers	42.7675%	NSPM No. of Residential Customers - 1,452,048	Total No. of Residential Customers - 3,702,819	NSPM No. of Calls - 25,610	Total No. of Calls - 55,289						
200162	Call Logging and Quality Management (CL/QM) FERC 903	Number of Customers/Number of Contacts	36.2123%	NSPM No. of Customers - 1,643,299	Total No. of Customers - 4,290,744	NSPM No. of Contacts - 1,159,268	Total No. of Contacts - 3,404,285						
200163	Employee Communications	Number of Employees	48.5194%	NSPM No. of Employees - 3,785	Total No. of Employees - 7,801								
200164	Payroll	Number of Employees	48.5194%	NSPM No. of Employees - 3,785	Total No. of Employees - 7,801								
200165	Employee Management Systems	Number of Employees	48.5194%	NSPM No. of Employees - 3,785	Total No. of Employees - 7,801								
200166	Human Resources (Diversity/Safety/Employee Relations)	Number of Employees	48.6004%	NSPM No. of Employees - 3,785	Total No. of Employees - 7,801								
200167	e-Business	Number of Employees	48.6004%	NSPM No. of Employees - 3,785	Total No. of Employees - 7,801								
200168	Gas Management System (GMS) FERC 866 & 880	No. of Gas Customers	0.0017%	NSPM No. of Gas Transport Customers - 27	Total No. of Gas Transport Customers - 8,181								
200169	Energy Supply Systems Miscellaneous FERC 417.1, 506, 539, & 549	No. of WAM ES Users	36.4855%	NSPM No. of WAM ES Users - 517	Total No. of WAM ES Users - 1,417								
200170	Meter Reading and Monitoring Systems FERC 902	Number of Meters	35.5498%	NSPM No. of Meters - 2,076,112	Total No. of Meters - 5,840,005								
200171	Customer Resource System (CRS) FERC 903	Number of Meters/Number of Contacts	34.8015%	NSPM No. of Meters - 2,076,112	Total No. of Meters - 5,840,005	NSPM No. of Contacts - 1,159,268	Total No. of Contacts - 3,404,285						
200172	Network	Phones/Radios/Computers	50.2755%	NSPM No. of Phones - 8,538	Total No. of Phones - 15,781	NSPM No. of Radios - 2,832	Total No. of Radios - 5,953	NSPM No. of Computers - 5,526	NSPM No. of Computers - 11,243				
200173	Generation Trading/Native Hedge - Back Office	Joint Operating Agreement Labor Hours Ratio	31.5833%	NSPM Percentage - 31.5833%	Total Percent - 100%								
200174	Generation Trading/Native Hedge - Mid Office FERC 557	Joint Operating Agreement Labor Hours Ratio	37.9151%	NSP Percentage - 37.9151%	Total Percent - 100%								
200176	Marketing & Sales	Revenue	42.2185%	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308								
200177	Rates & Regulation - Electric	Revenue	31.3292%	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308								
200178	Rates & Regulation	Revenue	31.3292%	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308								
200180	EMS-Shared (Energy Management System-SCADA) FERC 556, 561.2, & 581	Electric Production Plant/ Electric Transmission Plant/ Electric Distribution Plant	41.1404%	NSPM Gross Electric Prod Plant - $10,955,504	Total Gross Electric Prod Plant - $22,156,242	NSPM Gross Electric Trans Plant - $3,944,789	Total Gross Electric Trans Plant - $12,031,999	NSPM Gross Electric Dist Plant - $4,601,756	Total Gross Electric Dist Plant - $13,215,497				
200181	Energy Supply Environmental Policy & Services	Electric Production Plant/ Electric Transmission Plant/ Electric Distribution Plant/ Gas Transmission Plant/ Gas Distribution Plant	38.9619%	NSPM Gross Electric Prod Plant - $10,955,504	Total Gross Electric Prod Plant - $22,156,242	NSPM Gross Electric Trans Plant - $3,944,789	Total Gross Electric Trans Plant - $12,031,999	NSPM Gross Electric Dist Plant - $4,601,756	Total Gross Electric Dist Plant - $13,215,497	NSPM Gross Gas Trans Plant - $118,230	Total Gross Gas Trans Plant - $1,353,562	NSPM Gross Gas Dist Plant - $1,409,320	Total Gross Gas Dist Plant - $5,217,315
200182	Energy Supply Environmental Policy & Services NSPM & NSPW	Electric Production Plant/ Electric Transmission Plant/ Electric Distribution Plant/ Gas Transmission Plant/ Gas Distribution Plant	86.0579%	NSPM Gross Electric Prod Plant - $10,955,504	Total Gross Electric Prod Plant - $22,156,242	NSPM Gross Electric Trans Plant - $3,944,789	Total Gross Electric Trans Plant - $12,031,999	NSPM Gross Electric Dist Plant - $4,601,756	Total Gross Electric Dist Plant - $13,215,497	NSPM Gross Gas Trans Plant - $118,230	Total Gross Gas Trans Plant - $1,353,562	NSPM Gross Gas Dist Plant - $1,409,320	Total Gross Gas Dist Plant - $5,217,315
200184	PowerPlan	Total Plant	41.6215%	NSPM Plant Assets - $26,447,095	Total Plant Assets - $63,541,945								
200805	HomeSmart Revenue – Non-Utility 417.1	Revenues	72.4224%	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308								
200806	HomeSmart Customers – Non-Utility 417.1	No. of Customers	72.3632%	NSPM No. of Customers - 1,643,299	Total No. of Customers - 4,290,744								

XES Allocation Statistics (using allocated FTE Hours)
2022 Test Year Budget

Allocating Cost Center	Allocating Cost Center Description	Method of Allocation	Percentage	Allocation Statistics									
200063	Executive - Corporate Governance	Asset/Revenue/FTE Hours	37.4088%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM FTE Hours - 9,489	Total FTE Hours - 21,578				
200064	Shareholder - Corporate Governance	Asset/Revenue/FTE Hours	37.4088%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM FTE Hours - 9,489	Total FTE Hours - 21,578				
200065	Investor Relations - Corporate Governance	Asset/Revenue/FTE Hours	37.4088%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM FTE Hours - 9,489	Total FTE Hours - 21,578				
200066	Accounting, Reporting & Tax - Corporate Governance	Asset/Revenue/FTE Hours	37.4088%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM FTE Hours - 9,489	Total FTE Hours - 21,578				
200067	Audit Services - Corporate Governance	Asset/Revenue/FTE Hours	37.4088%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM FTE Hours - 9,489	Total FTE Hours - 21,578				
200068	Corporate Finance, Treasury & Cash Management - Corporate Governance	Asset/Revenue/FTE Hours	37.4088%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM FTE Hours - 9,489	Total FTE Hours - 21,578				
200069	Risk Management - Corporate Governance	Asset/Revenue/FTE Hours	37.4088%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM FTE Hours - 9,489	Total FTE Hours - 21,578				
200070	Corporate Strategy & Business Development - Corporate Governance	Asset/Revenue/FTE Hours	37.4088%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM FTE Hours - 9,489	Total FTE Hours - 21,578				
200071	Legal - Corporate Governance	Asset/Revenue/FTE Hours	37.4088%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM FTE Hours - 9,489	Total FTE Hours - 21,578				
200072	Communications - Corporate Governance	Asset/Revenue/FTE Hours	37.4088%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM FTE Hours - 9,489	Total FTE Hours - 21,578				
200073	Human Resources - Corporate Governance	Asset/Revenue/FTE Hours	37.4088%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM FTE Hours - 9,489	Total FTE Hours - 21,578				
200074	Corporate Systems – Corporate Governance	Asset/Revenue/FTE Hours	37.4088%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM FTE Hours - 9,489	Total FTE Hours - 21,578				
200075	Board of Directors - Corporate Governance	Asset/Revenue/FTE Hours	37.4088%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM FTE Hours - 9,489	Total FTE Hours - 21,578				
200076	Xcel Foundation	Asset/Revenue/FTE Hours	37.4780%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,589,824	NSPM FTE Hours - 9,489	Total FTE Hours - 21,578				
200077	Branding	Asset/Revenue/FTE Hours	37.4780%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,589,824	NSPM FTE Hours - 9,489	Total FTE Hours - 21,578				
200078	Governmental Affairs	Asset/Revenue/FTE Hours	37.5013%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,589,824	NSPM FTE Hours - 9,489	Total FTE Hours - 21,578				
200079	Federal Lobbying	Asset/Revenue/FTE Hours	37.5013%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,589,824	NSPM FTE Hours - 9,489	Total FTE Hours - 21,578				
200080	Capital Asset Accounting	Asset/Revenue/FTE Hours	42.6226%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM FTE Hours - 9,489	Total FTE Hours - 21,578				
200081	Accounting, Reporting & Taxes	Asset/Revenue/FTE Hours	42.7022%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM FTE Hours - 9,489	Total FTE Hours - 21,578				
200082	Audit Services	Asset/Revenue/FTE Hours	42.7022%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM FTE Hours - 9,489	Total FTE Hours - 21,578				
200083	Corporate Finance, Treasury & Cash Management	Asset/Revenue/FTE Hours	42.7022%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM FTE Hours - 9,489	Total FTE Hours - 21,578				
200084	Risk Management	Asset/Revenue/FTE Hours	42.7022%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM FTE Hours - 9,489	Total FTE Hours - 21,578				
200086	Legal & Claims Services	Asset/Revenue/FTE Hours	42.7022%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM FTE Hours - 9,489	Total FTE Hours - 21,578				
200087	Accounting, Reporting & Tax - Regulated	Asset/Revenue/FTE Hours	42.7137%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM FTE Hours - 9,489	Total FTE Hours - 21,578				
200088	Accounting, Reporting, Tax & Audit Services - Regulated Electric	Asset/Revenue/FTE Hours	42.7137%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM FTE Hours - 9,489	Total FTE Hours - 21,578				
200089	Audit Services - OpCo's & TransCo's	Asset/Revenue/FTE Hours	42.7137%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM FTE Hours - 9,489	Total FTE Hours - 21,578				
200090	Risk Management - OpCo's & TransCo's	Asset/Revenue/FTE Hours	42.7137%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM FTE Hours - 9,489	Total FTE Hours - 21,578				
200091	Captive Insurance	Asset/Revenue/FTE Hours	42.7137%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM FTE Hours - 9,489	Total FTE Hours - 21,578				
200092	Corporate Strategy & Business Development	Asset/Revenue/FTE Hours	42.7137%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM FTE Hours - 9,489	Total FTE Hours - 21,578				
200093	Legal - OpCo's & TransCo's	Asset/Revenue/FTE Hours	42.7137%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM FTE Hours - 9,489	Total FTE Hours - 21,578				
200094	Supply Chain	Asset/Revenue/FTE Hours	42.7137%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM FTE Hours - 9,489	Total FTE Hours - 21,578				
200095	Energy Supply Asset Management	Asset/Revenue/FTE Hours	42.7137%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM FTE Hours - 9,489	Total FTE Hours - 21,578				
200096	Energy Markets - Business Services	Asset/Revenue/FTE Hours	42.7137%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM FTE Hours - 9,489	Total FTE Hours - 21,578				
200097	Accounting and Finance Software Applications Maintenance	Asset/Revenue/FTE Hours	42.7137%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM FTE Hours - 9,489	Total FTE Hours - 21,578				
200098	Electric Transmission FERC 566	Asset/Revenue/FTE Hours	42.7137%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM FTE Hours - 9,489	Total FTE Hours - 21,578				
200099	Electric Distribution FERC 588	Asset/Revenue/FTE Hours	42.7137%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM FTE Hours - 9,489	Total FTE Hours - 21,578				
200100	Accounting, Reporting, Tax & Audit Services – Regulated Gas	Asset/Revenue/FTE Hours	50.4677%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM FTE Hours - 9,489	Total FTE Hours - 21,578				
200101	Legal Gas	Asset/Revenue/FTE Hours	50.4677%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM FTE Hours - 9,489	Total FTE Hours - 21,578				
200102	Gas Distribution FERC 880	Asset/Revenue/FTE Hours	50.4677%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM FTE Hours - 9,489	Total FTE Hours - 21,578				
200105	Accounting & Reporting - NSPM & NSPW	Asset/Revenue/FTE Hours	86.1580%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM FTE Hours - 9,489	Total FTE Hours - 21,578				
200106	Accounting & Reporting Electric - NSPM & NSPW	Asset/Revenue/FTE Hours	86.1580%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM FTE Hours - 9,489	Total FTE Hours - 21,578				
200107	Legal - NSPM & NSPW	Asset/Revenue/FTE Hours	86.1580%	NSPM Assets - $23,926,509	Total Assets - $77,363,635	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308	NSPM FTE Hours - 9,489	Total FTE Hours - 21,578				
200108	Advanced Metering Infrastructure (AMI)	No. of AMI Enabled Meters	56.2262%	NSPM No. of AMI Meters - 16,544	Total AMI Meters - 29,424								
200111	Enterprise Application Integration (EAI)	Average of a Select Set of Software Allocators	38.0516%	NSPM Percentage - 38.0516%	Total Percent - 100%								
200112	Mainframe Charges	Average of a Select Set of Software Allocators	26.5351%	NSPM Percentage - 26.5351%	Total Percent - 100%								
200115	Miscellaneous Applications	Average of all Software Percentages	34.8985%	NSPM Percentage - 34.8985%	Total Percent - 100%								
200116	Distribution Electric Supervision & Engineering (S&E) FERC 580	Electric Distribution Plant	34.8209%	NSPM Gross Electric Dist Plant - $4,601,756	Total Gross Electric Dist Plant - $13,215,497								
200117	Distribution Electric Metering FERC 586	Electric Distribution Plant	34.8209%	NSPM Gross Electric Dist Plant - $4,601,756	Total Gross Electric Dist Plant - $13,215,497								
200118	Distribution Electric Load Dispatching/EMS FERC 581	Electric Distribution Plant	34.8209%	NSPM Gross Electric Dist Plant - $4,601,756	Total Gross Electric Dist Plant - $13,215,497								
200119	Distribution Electric & Gas Miscellaneous FERC 588 & 880	Electric Distribution Plant/ Gas Distribution Plant	32.6107%	NSPM Gross Electric Dist Plant - $4,601,756	Total Gross Electric Dist Plant - $13,215,497	NSPM Gross Gas Dist Plant - $1,409,320	NSPM Gross Gas Dist Plant - $5,217,315						
200120	Distribution & Transmission Gas Emergency Response FERC 859 & 880	Gas Distribution Plant/Gas Transmission Plant	23.2473%	NSPM Gross Gas Dist Plant - $1,409,320	NSPM Gross Gas Dist Plant - $5,217,315	NSPM Gross Gas Trans Plant - $118,230	Total Gross Gas Trans Plant - $1,353,562						
200121	Distribution Electric & Gas and Transmission Gas Miscellaneous FERC 588, 880, & 859	Electric Distribution Plant/ Gas Transmission Plant/ Gas Distribution Plant	30.9774%	NSPM Gross Electric Dist Plant - $4,601,756	Total Gross Electric Dist Plant - $13,215,497	NSPM Gross Gas Trans Plant - $118,230	Total Gross Gas Trans Plant - $1,353,562	NSPM Gross Gas Dist Plant - $1,409,320	NSPM Gross Gas Dist Plant - $5,217,315				
200122	Transmission Electric Supervision & Engineering (S&E) FERC 560	Electric Transmission Plant	32.7858%	NSPM Gross Electric Trans Plant - $3,944,789	Total Gross Electric Trans Plant - $12,031,999								
200123	Transmission Electric Reliability, Planning, & Standards Development FERC 561.5	Electric Transmission Plant	32.7858%	NSPM Gross Electric Trans Plant - $3,944,789	Total Gross Electric Trans Plant - $12,031,999								
200124	Transmission Electric Load Dispatch-Monitor and Operate Transmission System FERC 561.2	Electric Transmission Plant	32.7858%	NSPM Gross Electric Trans Plant - $3,944,789	Total Gross Electric Trans Plant - $12,031,999								
200125	Transmission Electric Supervision & Engineering (S&E) NSPM & NSPW FERC 560	Electric Transmission Plant	73.5882%	NSPM Gross Electric Trans Plant - $3,944,789	Total Gross Electric Trans Plant - $12,031,999								

XES Allocation Statistics (using allocated FTE Hours)
2022 Test Year Budget

Allocating Cost Center	Allocating Cost Center Description	Method of Allocation	Percentage	Allocation Statistics									
200126	Utilities Group Administrative & General (A&G) FERC 921	Electric Transmission Plant/ Electric Distribution Plant/ Gas Transmission Plant/Gas Distribution Plant	31.6613%	NSPM Gross Electric Trans Plant - $3,944,789	Total Gross Electric Trans Plant - $12,031,999	NSPM Gross Electric Dist Plant - $4,601,756	Total Gross Electric Dist Plant - $13,215,497	NSPM Gross Gas Trans Plant - $118,230	Total Gross Gas Trans Plant - $1,353,562	NSPM Gross Gas Dist Plant - $1,409,320	NSPM Gross Gas Dist Plant - $5,217,315		
200127	Distribution Gas Supervision & Engineering (S&E) FERC 870	Gas Distribution Plant	27.0124%	NSPM Gross Gas Dist Plant - $1,409,320	NSPM Gross Gas Dist Plant - $5,217,315								
200128	Distribution Gas Miscellaneous FERC 880	Gas Distribution Plant	27.0124%	NSPM Gross Gas Dist Plant - $1,409,320	NSPM Gross Gas Dist Plant - $5,217,315								
200129	Distribution Gas Meters and House Regulators FERC 878	Gas Distribution Plant	27.0124%	NSPM Gross Gas Dist Plant - $1,409,320	NSPM Gross Gas Dist Plant - $5,217,315								
200130	Transmission Gas Supervision & Engineering (S&E) FERC 850	Gas Transmission Plant	8.7347%	NSPM Gross Gas Trans Plant - $118,230	Total Gross Gas Trans Plant - $1,353,562								
200131	Distribution & Transmission Gas System Control and Load Dispatching FERC 851 & 871	Gas Transmission Plant/ Gas Distribution Plant	23.2473%	NSPM Gross Gas Trans Plant - $118,230	Total Gross Gas Trans Plant - $1,353,562	NSPM Gross Gas Dist Plant - $1,409,320	NSPM Gross Gas Dist Plant - $5,217,315						
200132	Payment & Reporting	Invoice Transactions	26.4351%	NSPM Invoice Transactions - 136,897	Total Invoice Transactions 517,861								
200133	Proprietary Trading - Back Office	Joint Operating Agreement Peak Hour Megawatt Load Ratio	36.5625%	NSPM Peak MWH - 8,570	Total Peak MWH - 19,525								
200134	Proprietary Trading - Front/Mid Office FERC 557	Joint Operating Agreement Peak Hour Megawatt Load Ratio	43.8925%	NSPM Peak MWH - 8,570	Total Peak MWH - 19,525								
200135	Energy Supply Business Resources	MWH Generation (000's)	35.3947%	NSPM MWH Generation - 21,289,608	Total MWH Generation - 60,149,134								
200136	Energy Markets - Fuel	MWH Generation (000's)	35.3947%	NSPM MWH Generation - 21,289,608	Total MWH Generation - 60,149,134								
200137	Energy Supply Miscellaneous Power Expense FERC 506, 539, & 549	MWH Generation (000's)	35.3947%	NSPM MWH Generation - 21,289,608	Total MWH Generation - 60,149,134								
200138	Energy Supply Operation Supervision & Engineering (S&E) FERC 500, 535, & 546	MWH Generation (000's)	35.3947%	NSPM MWH Generation - 21,289,608	Total MWH Generation - 60,149,134								
200139	Energy Supply Maintenance Supervision & Engineering (S&E) FERC 510, 541, & 551	MWH Generation (000's)	35.3947%	NSPM MWH Generation - 21,289,608	Total MWH Generation - 60,149,134								
200143	Energy Supply Miscellaneous Power Expense NSPM & NSPW FERC 506, 539, & 549	MWH Generation (000's)	93.8813%	NSPM MWH Generation - 21,289,608	Total MWH Generation - 60,149,134								
200144	Energy Supply Operation Supervision & Engineering (S&E) NSPM & NSPW FERC 500, 535, & 546	MWH Generation (000's)	93.8813%	NSPM MWH Generation - 21,289,608	Total MWH Generation - 60,149,134								
200145	Energy Supply Maintenance Supervision & Engineering (S&E) NSPM & NSPW FERC 510, 541, & 551	MWH Generation (000's)	93.8813%	NSPM MWH Generation - 21,289,608	Total MWH Generation - 60,149,134								
200146	Energy Markets - Regulated Trading	MWH Hours Sold (000's)	35.7964%	NSPM MWh Hour Sales - 39,627,640	Total MWh Hour Sales - 110,702,985								
200147	Business Objects	Number of Business Objects Users	50.0218%	NSPM No. of Business Objects users - 1,151	Total No. of Business Objects users - 2,301								
200148	Business Systems	Number of Computers	49.1506%	NSPM No. of Computers - 5,526	NSPM No. of Computers - 11,243								
200149	Customer & Enterprise Solutions (CES)	Number of - Computers/Customers/Employees	43.8591%	NSPM No. of Computers - 5,526	NSPM No. of Computers - 11,243	NSPM No. of Customers - 1,643,299	Total No. of Customers - 4,290,744	NSPM FTE Hours - 9,489	Total FTE Hours - 21,578				
200150	Interactive Voice Response (IVR)	Number of Contacts	34.0532%	NSPM No. of Contacts - 1,159,268	Total No. of Contacts - 3,404,285								
200151	Customer Billing FERC 903	Number of Customer Bills	39.0927%	NSPM No. of Customer Bills - 1,525,218	Total No. of Customer Bills - 3,901,545								
200152	Customer Care FERC 902	Number of Customers	38.2987%	NSPM No. of Customers - 1,643,299	Total No. of Customers - 4,290,744								
200153	Customer Safety Advertising & Information Costs	Number of Customers	38.3714%	NSPM No. of Customers - 1,643,299	Total No. of Customers - 4,290,744								
200154	Customer Service Information Technology (IT) FERC 903	Number of Customers	38.3714%	NSPM No. of Customers - 1,643,299	Total No. of Customers - 4,290,744								
200155	Customer Care FERC 903	Number of Customers	38.3714%	NSPM No. of Customers - 1,643,299	Total No. of Customers - 4,290,744								
200156	Customer Care FERC 901	Number of Customers	38.3714%	NSPM No. of Customers - 1,643,299	Total No. of Customers - 4,290,744								
200159	Customer Service Information Technology (IT) NSPM & NSPW FERC 903	Number of Customers	85.1316%	NSPM No. of Customers - 1,643,299	Total No. of Customers - 4,290,744								
200160	Customer Care NSPM & NSPW FERC 903	Number of Customers	85.1316%	NSPM No. of Customers - 1,643,299	Total No. of Customers - 4,290,744								
200161	Customer Care Low Income Assistance FERC 908	No. of Residential Customers	42.7675%	NSPM No. of Residential Customers - 1,452,048	Total No. of Residential Customers - 3,702,819	NSPM No. of Calls - 25,610	Total No. of Calls - 55,289						
200162	Call Logging and Quality Management (CL/QM) FERC 903	Number of Customers/Number of Contacts	36.2123%	NSPM No. of Customers - 1,643,299	Total No. of Customers - 4,290,744	NSPM No. of Contacts - 1,159,268	Total No. of Contacts - 3,404,285						
200163	Employee Communications	FTE Hours	44.0539%	NSPM FTE Hours - 9,489	Total FTE Hours - 21,578								
200164	Payroll	FTE Hours	44.0539%	NSPM FTE Hours - 9,489	Total FTE Hours - 21,578								
200165	Employee Management Systems	FTE Hours	44.0539%	NSPM FTE Hours - 9,489	Total FTE Hours - 21,578								
200166	Human Resources (Diversity/Safety/Employee Relations)	FTE Hours	44.0553%	NSPM FTE Hours - 9,489	Total FTE Hours - 21,578								
200167	e-Business	FTE Hours	44.0553%	NSPM FTE Hours - 9,489	Total FTE Hours - 21,578								
200168	Gas Management System (GMS) FERC 866 & 880	No. of Gas Customers	0.0017%	NSPM No. of Gas Transport Customers - 27	Total No. of Gas Transport Customers - 8,181								
200169	Energy Supply Systems Miscellaneous FERC 417.1, 506, 539, & 549	No. of WAM ES Users	36.4855%	NSPM No. of WAM ES Users - 517	Total No. of WAM ES Users - 1,417								
200170	Meter Reading and Monitoring Systems FERC 902	Number of Meters	35.5498%	NSPM No. of Meters - 2,076,112	Total No. of Meters - 5,840,005								
200171	Customer Resource System (CRS) FERC 903	Number of Meters/Number of Contacts	34.8015%	NSPM No. of Meters - 2,076,112	Total No. of Meters - 5,840,005	NSPM No. of Contacts - 1,159,268	Total No. of Contacts - 3,404,285						
200172	Network	Phones/Radios/Computers	50.2755%	NSPM No. of Phones - 8,538	Total No. of Phones - 15,781	NSPM No. of Radios - 2,832	Total No. of Radios - 5,953	NSPM No. of Computers - 5,526	NSPM No. of Computers - 11,243				
200173	Generation Trading/Native Hedge - Back Office	Joint Operating Agreement Labor Hours Ratio	31.5833%	NSPM Percentage - 31.5833%	Total Percent - 100%								
200174	Generation Trading/Native Hedge - Mid Office FERC 557	Joint Operating Agreement Labor Hours Ratio	37.9151%	NSP Percentage - 37.9151%	Total Percent - 100%								
200176	Marketing & Sales	Revenue	42.2185%	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308								
200177	Rates & Regulation - Electric	Revenue	31.3292%	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308								
200178	Rates & Regulation	Revenue	31.3292%	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308								
200180	EMS-Shared (Energy Management System-SCADA) FERC 556, 561.2, & 581	Electric Production Plant/ Electric Transmission Plant/ Electric Distribution Plant	41.1404%	NSPM Gross Electric Prod Plant - $10,955,504	Total Gross Electric Prod Plant - $22,156,242	NSPM Gross Electric Trans Plant - $3,944,789	Total Gross Electric Trans Plant - $12,031,999	NSPM Gross Electric Dist Plant - $4,601,756	Total Gross Electric Dist Plant - $13,215,497				
200181	Energy Supply Environmental Policy & Services	Electric Production Plant/ Electric Transmission Plant/ Electric Distribution Plant/ Gas Transmission Plant/ Gas Distribution Plant	38.9619%	NSPM Gross Electric Prod Plant - $10,955,504	Total Gross Electric Prod Plant - $22,156,242	NSPM Gross Electric Trans Plant - $3,944,789	Total Gross Electric Trans Plant - $12,031,999	NSPM Gross Electric Dist Plant - $4,601,756	Total Gross Electric Dist Plant - $13,215,497	NSPM Gross Gas Trans Plant - $118,230	Total Gross Gas Trans Plant - $1,353,562	NSPM Gross Gas Dist Plant - $1,409,320	Total Gross Gas Dist Plant - $5,217,315
200182	Energy Supply Environmental Policy & Services NSPM & NSPW	Electric Production Plant/ Electric Transmission Plant/ Electric Distribution Plant/ Gas Transmission Plant/ Gas Distribution Plant	86.0579%	NSPM Gross Electric Prod Plant - $10,955,504	Total Gross Electric Prod Plant - $22,156,242	NSPM Gross Electric Trans Plant - $3,944,789	Total Gross Electric Trans Plant - $12,031,999	NSPM Gross Electric Dist Plant - $4,601,756	Total Gross Electric Dist Plant - $13,215,497	NSPM Gross Gas Trans Plant - $118,230	Total Gross Gas Trans Plant - $1,353,562	NSPM Gross Gas Dist Plant - $1,409,320	Total Gross Gas Dist Plant - $5,217,315
200184	PowerPlan	Total Plant	41.6215%	NSPM Plant Assets - $26,447,095	Total Plant Assets - $63,541,945								
200805	HomeSmart Revenue – Non-Utility 417.1	Revenues	72.4224%	NSPM Revenues - $5,204,538	Total Revenues - $13,968,308								
200806	HomeSmart Customers – Non-Utility 417.1	No. of Customers	72.3632%	NSPM No. of Customers - 1,643,299	Total No. of Customers - 4,290,744								

Impact to NSPM 2022 Test Year for Change in XES Allocations
Using FTE Method instead of Number of Employees
2022 Budget Test Year

							Current Method					FTE Hours Method					Impact				
Allocating Cost Center	Allocating Cost Center Description	Allocation Method	Current Method	FTE Hours Method	Variance	XES Total Amount (2022 Budget)	NSPM Total Company Amount	Common	Electric	Gas	Non-Reg	NSPM Total Company Revised Amount	Common	Electric	Gas	Non-Reg	NSPM Impact	Common	Electric	Gas	Non-Reg
200063	Executive - Corporate Governance	Assets/Revenue/No. of Employees (Corp Gov)	38.9021%	37.4088%	-1.4933%	$ 71,765,372	$ 27,918,237	$ 27,918,237	$ -	$ -	$ -	$ 26,846,564	$ 26,846,564	$ -	$ -	$ -	$ (1,071,672)	$ (1,071,672)	$ -	$ -	$ -
200064	Shareholder - Corporate Governance	Assets/Revenue/No. of Employees (Corp Gov)	38.9021%	37.4088%	-1.4933%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
200065	Investor Relations - Corporate Governance	Assets/Revenue/No. of Employees (Corp Gov)	38.9021%	37.4088%	-1.4933%	2,028,471	789,118	789,118	-	-	-	758,827	758,827	-	-	-	(30,291)	(30,291)	-	-	-
200066	Accounting, Reporting & Tax - Corporate Governance	Assets/Revenue/No. of Employees (Corp Gov)	38.9021%	37.4088%	-1.4933%	24,201,439	9,414,868	9,414,868	-	-	-	9,053,468	9,053,468	-	-	-	(361,400)	(361,400)	-	-	-
200067	Audit Services - Corporate Governance	Assets/Revenue/No. of Employees (Corp Gov)	38.9021%	37.4088%	-1.4933%	3,207,021	1,247,599	1,247,599	-	-	-	1,199,708	1,199,708	-	-	-	(47,890)	(47,890)	-	-	-
200068	Corporate Finance, Treasury & Cash Management - Corporate Governance	Assets/Revenue/No. of Employees (Corp Gov)	38.9021%	37.4088%	-1.4933%	10,572,481	4,112,917	4,112,917	-	-	-	3,955,038	3,955,038	-	-	-	(157,879)	(157,879)	-	-	-
200069	Risk Management - Corporate Governance	Assets/Revenue/No. of Employees (Corp Gov)	38.9021%	37.4088%	-1.4933%	506,010	196,849	196,849	-	-	-	189,292	189,292	-	-	-	(7,556)	(7,556)	-	-	-
200070	Corporate Strategy & Business Development - Corporate Governance	Assets/Revenue/No. of Employees (Corp Gov)	38.9021%	37.4088%	-1.4933%	2,409,439	937,322	937,322	-	-	-	901,342	901,342	-	-	-	(35,980)	(35,980)	-	-	-
200071	Legal - Corporate Governance	Assets/Revenue/No. of Employees (Corp Gov)	38.9021%	37.4088%	-1.4933%	14,724,042	5,727,962	5,727,962	-	-	-	5,508,088	5,508,088	-	-	-	(219,874)	(219,874)	-	-	-
200072	Communications - Corporate Governance	Assets/Revenue/No. of Employees (Corp Gov)	38.9021%	37.4088%	-1.4933%	6,374,057	2,479,642	2,479,642	-	-	-	2,384,458	2,384,458	-	-	-	(95,184)	(95,184)	-	-	-
200073	Human Resources - Corporate Governance	Assets/Revenue/No. of Employees (Corp Gov)	38.9021%	37.4088%	-1.4933%	6,139,212	2,388,282	2,388,282	-	-	-	2,296,605	2,296,605	-	-	-	(91,677)	(91,677)	-	-	-
200074	Corporate Systems – Corporate Governance	Assets/Revenue/No. of Employees (Corp Gov)	38.9021%	37.4088%	-1.4933%	22,315,250	8,681,101	8,681,101	-	-	-	8,347,867	8,347,867	-	-	-	(333,234)	(333,234)	-	-	-
200075	Board of Directors - Corporate Governance	Asset/Revenue/Number of Employees	38.9021%	37.4088%	-1.4933%	4,091,672	1,591,746	1,591,746	-	-	-	1,530,645	1,530,645	-	-	-	(61,101)	(61,101)	-	-	-
200076	Xcel Foundation	Assets/Revenue/No. of Employees (Corp Gov)	38.9671%	37.4780%	-1.4891%	1,345,143	524,163	524,163	-	-	-	504,133	504,133	-	-	-	(20,031)	(20,031)	-	-	-
200077	Branding	Assets/Revenue/No. of Employees (Corp Gov)	38.9671%	37.4780%	-1.4891%	12,911,285	5,031,153	5,031,153	-	-	-	4,838,891	4,838,891	-	-	-	(192,262)	(192,262)	-	-	-
200078	Governmental Affairs	Assets/Revenue/No. of Employees	38.9904%	37.5013%	-1.4891%	4,325,610	1,686,573	1,686,573	-	-	-	1,622,160	1,622,160	-	-	-	(64,413)	(64,413)	-	-	-
200079	Federal Lobbying	Assets/Revenue/No. of Employees	38.9904%	37.5013%	-1.4891%	1,093,002	426,166	-	-	-	426,166	409,890	-	-	-	409,890	(16,276)	-	-	-	(16,276)
200080	Capital Asset Accounting	Assets/Revenue/No. of Employees(Unique Iteration of me	44.1421%	42.6226%	-1.5195%	1,025,501	452,678	452,678	-	-	-	437,095	437,095	-	-	-	(15,582)	(15,582)	-	-	-
200081	Accounting, Reporting & Taxes	Assets/Revenue/No. of Employees	44.2178%	42.7022%	-1.5156%	129,069	57,071	57,071	-	-	-	55,115	55,115	-	-	-	(1,956)	(1,956)	-	-	-
200082	Audit Services	Assets/Revenue/No. of Employees	44.2178%	42.7022%	-1.5156%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
200083	Corporate Finance, Treasury & Cash Management	Asset/Revenue/Number of Employees	44.2178%	42.7022%	-1.5156%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
200084	Risk Management	Asset/Revenue/Number of Employees	44.2178%	42.7022%	-1.5156%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
200086	Legal & Claims Services	Assets/Revenue/No. of Employees	44.2178%	42.7022%	-1.5156%	992,834	439,009	439,009	-	-	-	423,962	423,962	-	-	-	(15,047)	(15,047)	-	-	-
200087	Accounting, Reporting & Tax - Regulated	Assets/Revenue/No. of Employees	44.2290%	42.7137%	-1.5153%	11,801,610	5,219,734	5,219,734	-	-	-	5,040,904	5,040,904	-	-	-	(178,830)	(178,830)	-	-	-
200088	Accounting, Reporting, Tax & Audit Services - Regulated Electric	Assets/Revenue/No. of Employees	44.2290%	42.7137%	-1.5153%	7,098,191	3,139,459	-	3,139,459	-	-	3,031,900	-	3,031,900	-	-	(107,559)	-	(107,559)	-	-
200089	Audit Services - OpCo's & TransCo's	Assets/Revenue/No. of Employees	44.2290%	42.7137%	-1.5153%	147,492	65,234	65,234	-	-	-	62,999	62,999	-	-	-	(2,235)	(2,235)	-	-	-
200090	Risk Management - OpCo's & TransCo's	Assets/Revenue/No. of Employees	44.2290%	42.7137%	-1.5153%	3,606,029	1,594,911	1,594,911	-	-	-	1,540,268	1,540,268	-	-	-	(54,642)	(54,642)	-	-	-
200091	Captive Insurance	Assets/Revenue/No. of Employees	44.2290%	42.7137%	-1.5153%	19,673,639	8,701,454	8,701,454	-	-	-	8,403,339	8,403,339	-	-	-	(298,115)	(298,115)	-	-	-
200092	Corporate Strategy & Business Development	Assets/Revenue/No. of Employees	44.2290%	42.7137%	-1.5153%	5,940,864	2,627,585	2,627,585	-	-	-	2,537,563	2,537,563	-	-	-	(90,022)	(90,022)	-	-	-
200093	Legal - OpCo's & TransCo's	Assets/Revenue/No. of Employees	44.2290%	42.7137%	-1.5153%	56,100	24,812	24,812	-	-	-	23,962	23,962	-	-	-	(850)	(850)	-	-	-
200094	Supply Chain	Assets/Revenue/No. of Employees	44.2290%	42.7137%	-1.5153%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
200095	Energy Supply Asset Management	Assets/Revenue/No. of Employees	44.2290%	42.7137%	-1.5153%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
200096	Energy Markets - Business Services	Assets/Revenue/No. of Employees	44.2290%	42.7137%	-1.5153%	3,675,100	1,625,460	1,625,460	-	-	-	1,569,771	1,569,771	-	-	-	(55,689)	(55,689)	-	-	-
200097	Accounting and Finance Software Applications Maintenance	Asset/Revenue/Number of Employees	44.2290%	42.7137%	-1.5153%	588,912	260,470	260,470	-	-	-	251,546	251,546	-	-	-	(8,924)	(8,924)	-	-	-
200098	Electric Transmission FERC 566	Assets/Revenue/No. of Employees	44.2290%	42.7137%	-1.5153%	761,860	336,963	-	336,963	-	-	325,419	-	325,419	-	-	(11,544)	-	(11,544)	-	-
200099	Electric Distribution FERC 588	Assets/Revenue/No. of Employees	44.2290%	42.7137%	-1.5153%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
200100	Accounting, Reporting, Tax & Audit Services – Regulated Gas	Assets/Revenue/No. of Employees	52.1537%	50.4677%	-1.6860%	63,096	32,907	-	-	32,907	-	31,843	-	-	31,843	-	(1,064)	-	-	(1,064)	-
200101	Legal Gas	Assets/Revenue/No. of Employees	52.1537%	50.4677%	-1.6860%	646,710	337,283	-	-	337,283	-	326,380	-	-	326,380	-	(10,904)	-	-	(10,904)	-
200102	Gas Distribution FERC 880	Assets/Revenue/No. of Employees	52.1537%	50.4677%	-1.6860%	95,821	49,974	-	-	49,974	-	48,359	-	-	48,359	-	(1,616)	-	-	(1,616)	-
200105	Accounting & Reporting - NSPM & NSPW	Assets/Revenue/No. of Employees	86.9558%	86.1580%	-0.7978%	558,468	485,620	485,620	-	-	-	481,165	481,165	-	-	-	(4,455)	(4,455)	-	-	-
200106	Accounting & Reporting Electric - NSPM & NSPW	Assets/Revenue/No. of Employees	86.9558%	86.1580%	-0.7978%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
200107	Legal - NSPM & NSPW	Assets/Revenue/No. of Employees	86.9558%	86.1580%	-0.7978%	35,000	30,435	30,435	-	-	-	30,155	30,155	-	-	-	(279)	(279)	-	-	-
200111	Enterprise Application Integration (EAI)	Average of a Select Set of Software Allocators	39.0533%	38.0516%	-1.0017%	119,907,184	46,827,712	37,600,615	6,140,327	3,086,771	-	45,626,602	36,399,505	6,140,327	3,086,771	-	(1,201,110)	(1,201,110)	-	-	-
200112	Mainframe Charges	Average of a Select Set of Software Allocators	28.0236%	26.5351%	-1.4885%	5,181,009	1,451,905	1,451,874	-	31	-	1,374,786	1,374,755	-	31	-	(77,119)	(77,119)	-	-	-
200115	Miscellaneous Applications	Average of All Software Percentages	35.5212%	34.8985%	-0.6227%	33,019,684	11,728,988	8,055,977	2,822,952	850,059	-	11,523,374	7,850,364	2,822,952	850,059	-	(205,614)	(205,614)	-	-	-
200149	Customer & Enterprise Solutions (CES)	Number of Computers/Number of Customers/Number of E	45.3742%	43.8591%	-1.5151%	5,207,904	2,363,045	2,363,045	-	-	-	2,284,140	2,284,140	-	-	-	(78,905)	(78,905)	-	-	-
200163	Employee Communications	No. Of Employees	48.5194%	44.0539%	-4.4655%	647,823	314,320	314,320	-	-	-	285,391	285,391	-	-	-	(28,929)	(28,929)	-	-	-
200164	Payroll	No. Of Employees	48.5194%	44.0539%	-4.4655%	1,442,474	699,880	699,880	-	-	-	635,466	635,466	-	-	-	(64,414)	(64,414)	-	-	-
200165	Employee Management Systems	No. Of Employees	48.5194%	44.0539%	-4.4655%	17,805,266	8,639,008	8,639,008	-	-	-	7,843,914	7,843,914	-	-	-	(795,094)	(795,094)	-	-	-
200166	Human Resources (Diversity/Safety/Employee Relations)	No. Of Employees	48.6004%	44.0553%	-4.5451%	27,688,540	13,456,741	13,456,741	-	-	-	12,198,269	12,198,269	-	-	-	(1,258,472)	(1,258,472)	-	-	-
200167	e-Business	No. Of Employees	48.6004%	44.0553%	-4.5451%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

NSPM Total Company Amount	Common	Electric	Gas	Non-Reg	NSPM Total Company Revised Amount	Common	Electric	Gas	Non-Reg	NSPM 2022 Budget Impact	Common	Electric	Gas	Non-Reg
$ 184,116,356	$ 166,893,465	$ 12,439,701	$ 4,357,025	$ 426,166	$ 176,740,667	$ 159,666,738	$ 12,320,597	$ 4,343,442	$ 409,890	$ (7,375,689)	$ (7,226,727)	$ (119,103)	$ (13,583)	$ (16,276)

Northern States Power Company

Impact to NSPM 2022 Test Year for Change in XES Allocations
Using FTE Method instead of Number of Employees
2022 Budget Test Year

	E/G Allocator	**Two Factor Jurisdictional Allocator**			**E/G Allocator**	**Customer Allocator**	
	93.59%	**87.16%**	**6.12%**	**6.72%**	**6.41%**	**88.65%**	**11.35%**
Allocating Cost Center	**NSPM Elec**	**MN Elec**	**ND Elec**	**SD Elec**	**NSPM Gas**	**MN Gas**	**ND Gas**
200063	$ (1,003,027)	$ (874,232)	$ (61,362)	$ (67,433)	$ (68,645)	$ (60,854)	$ (7,791)
200064	-	-	-	-	-	-	-
200065	(28,351)	(24,711)	(1,734)	(1,906)	(1,940)	(1,720)	(220)
200066	(338,251)	(294,818)	(20,693)	(22,740)	(23,149)	(20,522)	(2,627)
200067	(44,823)	(39,067)	(2,742)	(3,013)	(3,068)	(2,720)	(348)
200068	(147,766)	(128,792)	(9,040)	(9,934)	(10,113)	(8,965)	(1,148)
200069	(7,072)	(6,164)	(433)	(475)	(484)	(429)	(55)
200070	(33,675)	(29,351)	(2,060)	(2,264)	(2,305)	(2,043)	(262)
200071	(205,790)	(179,365)	(12,590)	(13,835)	(14,084)	(12,485)	(1,599)
200072	(89,087)	(77,648)	(5,450)	(5,989)	(6,097)	(5,405)	(692)
200073	(85,805)	(74,787)	(5,249)	(5,769)	(5,872)	(5,206)	(666)
200074	(311,889)	(271,841)	(19,080)	(20,968)	(21,345)	(18,922)	(2,423)
200075	(57,187)	(49,844)	(3,499)	(3,845)	(3,914)	(3,470)	(444)
200076	(18,747)	(16,340)	(1,147)	(1,260)	(1,283)	(1,137)	(146)
200077	(179,947)	(156,841)	(11,009)	(12,098)	(12,315)	(10,917)	(1,398)
200078	(60,287)	(52,546)	(3,688)	(4,053)	(4,126)	(3,658)	(468)
200079	-	-	-	-	-	-	-
200080	(14,584)	(12,711)	(892)	(980)	(998)	(885)	(113)
200081	(1,831)	(1,596)	(112)	(123)	(125)	(111)	(14)
200082	-	-	-	-	-	-	-
200083	-	-	-	-	-	-	-
200084	-	-	-	-	-	-	-
200086	(14,084)	(12,276)	(862)	(947)	(964)	(855)	(109)
200087	(167,375)	(145,883)	(10,240)	(11,252)	(11,455)	(10,155)	(1,300)
200088	(107,559)	(93,748)	(6,580)	(7,231)	-	-	-
200089	(2,092)	(1,823)	(128)	(141)	(143)	(127)	(16)
200090	(51,142)	(44,575)	(3,129)	(3,438)	(3,500)	(3,103)	(397)
200091	(279,019)	(243,191)	(17,070)	(18,758)	(19,095)	(16,928)	(2,167)
200092	(84,256)	(73,437)	(5,155)	(5,664)	(5,766)	(5,112)	(654)
200093	(796)	(694)	(49)	(54)	(54)	(48)	(6)
200094	-	-	-	-	-	-	-
200095	-	-	-	-	-	-	-
200096	(52,122)	(45,429)	(3,189)	(3,504)	(3,567)	(3,162)	(405)
200097	(8,352)	(7,280)	(511)	(562)	(572)	(507)	(65)
200098	(11,544)	(10,062)	(706)	(776)	-	-	-
200099	-	-	-	-	-	-	-
200100	-	-	-	-	(1,064)	(943)	(121)
200101	-	-	-	-	(10,904)	(9,666)	(1,238)
200102	-	-	-	-	(1,616)	(1,433)	(183)
200105	(4,170)	(3,635)	(255)	(280)	(285)	(253)	(32)
200106	-	-	-	-	-	-	-
200107	(261)	(227)	(16)	(18)	(18)	(16)	(2)
200111	(1,124,174)	(979,823)	(68,774)	(75,577)	(76,936)	(68,204)	(8,732)
200112	(72,180)	(62,912)	(4,416)	(4,853)	(4,940)	(4,379)	(561)
200115	(192,443)	(167,732)	(11,773)	(12,938)	(13,170)	(11,675)	(1,495)
200149	(73,851)	(64,368)	(4,518)	(4,965)	(5,054)	(4,480)	(574)
200163	(27,076)	(23,599)	(1,656)	(1,820)	(1,853)	(1,643)	(210)
200164	(60,288)	(52,547)	(3,688)	(4,053)	(4,126)	(3,658)	(468)
200165	(744,165)	(648,610)	(45,526)	(50,029)	(50,929)	(45,148)	(5,781)
200166	(1,177,862)	(1,026,617)	(72,058)	(79,186)	(80,610)	(71,461)	(9,149)
200167	-	-	-	-	-	-	-
	$ (6,882,930)	$ (5,999,120)	$ (421,077)	$ (462,732)	$ (476,484)	**$ (422,402)**	$ (54,082)

Minnesota Jurisdiction Electric Long Term Incentive Adjustment	5,845
Minnesota Jurisdiction Electric Payroll Tax Adjustment	(4,484)

Total Minnesota Jurisdiction Gas Adjustment $ (421,041)

THIS FILING IS		
Item 1: ☒ An Initial (Original) Submission	OR ☐	Resubmission No. ____

Form 60 Approved
OMB No. 1902-0215
Expires 01/31/2023

FERC FINANCIAL REPORT
FERC FORM No. 60: Annual Report of Centralized Service Companies

Exact Legal Name of Respondent (Company)	**Year of Report**
Xcel Energy Services Inc.	**Dec 31,** 2020

GENERAL INSTRUCTIONS FOR FILING FERC FORM NO. 60

I. Purpose

Form No. 60 is an annual regulatory support requirement under 18 CFR 369.1for centralized service companies. The report is designed to collect financial information from centralized service companies subject to the jurisdiction of the Federal Energy Regulatory Commission. The report is considered to be a non-confidential public use form.

II. Who Must Submit

Unless the holding company system is exempted or granted a waiver by Commission rule or order pursuant to §§ 18 CFR 366.3 and 366.4 of this chapter, every centralized service company (see § 367.2) in a holding company system must prepare and file electronically with the Commission the FERC Form No. 60 then in effect pursuant to the General Instructions set out in this form.

III. How to Submit

Submit FERC Form No. 60 electronically through the Form No. 60 Submission Software. Retain one copy of each report for your files. For any resubmissions, submit the filing using the Form No. 60 Submission Software including a justification. Respondents must submit the Corporate Officer Certification electronically.

IV. When to Submit

Submit FERC Form No. 60 according to the filing date contained § 18 CFR 369.1 of the Commission's regulations.

V. Preparation

Prepare this report in conformity with the Uniform System of Accounts (18 CFR 367) (USof A). Interpret all accounting words and phrases in accordance with the USof A.

VI. Time Period

This report covers the entire calendar year.

VII. Whole Dollar Usage

Enter in whole numbers (dollars) only, except where otherwise noted. The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's amounts.

VIII. Accurateness

Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

IX. Applicability

For any page(s) that is not applicable to the respondent, enter "NONE," or "Not Applicable" in column (c) on the List of Schedules, page 2.

X. Date Format

Enter the month, day, and year for all dates. Use customary abbreviations. The "Resubmission Date" included in the header of each page is to be completed only for resubmissions (see III. above).

XI. Number Format

Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by use of a minus sign.

XII. Required Entries

Do not make references to reports of previous years or to other reports instead of required entries, except as specifically authorized.

XIII. Prior Year References

Wherever (schedule) pages refer to figures from a previous year, the figures reported must be based upon those shown by the report of the previous year, or an appropriate explanation given as to why the different figures were used.

XIV. Where to Send Comments on Public Reporting Burden

The public reporting burden for the Form No. 60 collection of information is estimated to average 75 hours per response, including

- the time for reviewing instructions, searching existing data sources,
- gathering and maintaining the data-needed, and
- completing and reviewing the collection of information.

Send comments regarding these burden estimates or any aspect of this collection of information, including suggestions for reducing burden, to:

Federal Energy Regulatory Commission, (Attention: Information Clearance Officer, CIO),
888 First Street NE,
Washington, DC 20426
or by email to DataClearance@ferc.gov

And to:

Office of Information and Regulatory Affairs,
Office of Management and Budget, Washington, DC 20503 (Attention: Desk Office for the Federal Energy Regulatory Commission).
Comments to OMB should be submitted by email to: oira_submission@omb.eop.gov

No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. 3512(a)).

DEFINITIONS
I. Respondent -- The person, corporation, or other legal entity in whose behalf the report is made.

FERC FORM NO. 60
ANNUAL REPORT FOR SERVICE COMPANIES

IDENTIFICATION

01 Exact Legal Name of Respondent Xcel Energy Services Inc.	02 Year of Report Dec 31, 2020
03 Previous Name (If name changed during the year)	04 Date of Name Change / /
05 Address of Principal Office at End of Year (Street, City, State, Zip Code) 414 Nicollet Mall, Minneapolis, MN 55401	06 Name of Contact Person Jeffrey S. Savage
07 Title of Contact Person Senior Vice President, Controller	08 Address of Contact Person 414 Nicollet Mall, Minneapolis, MN 55401
09 Telephone Number of Contact Person (612) 330-5658	10 E-mail Address of Contact Person Jeffret.S.Savage@xcelenergy.com
11 This Report is: (1) [X] An Original (2) [ ] A Resubmission	12 Resubmission Date (Month, Day, Year) / /
13 Date of Incorporation 04/02/1997	14 If Not Incorporated, Date of Organization / /
15 State or Sovereign Power Under Which Incorporated or Organized DELAWARE	
16 Name of Principal Holding Company Under Which Reporting Company is Organized: Xcel Energy, Inc.	

CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

17 Name of Signing Officer Jeffrey S. Savage	19 Signature of Signing Officer Jeffrey S. Savage	20 Date Signed (Month, Day, Year) 04/07/2021
18 Title of Signing Officer Senior Vice President, Controller		

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
Xcel Energy Services Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2020

List of Schedules and Accounts

1. Enter in Column (c) the terms “None” or “Not Applicable” as appropriate, where no information or amounts have been reported for certain pages.

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
Xcel Energy Services Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2020

Schedule I - Comparative Balance Sheet

1. Give balance sheet of the Company as of December 31 of the current and prior year.

Line No.	Account Number (a)	Description (b)	Reference Page No. (c)	As of Dec 31 Current (d)	As of Dec 31 Prior (e)
1		**Service Company Property**			
2	101	Service Company Property	103	13,283,331	18,473,574
3	101.1	Property Under Capital Leases	103		
4	106	Completed Construction Not Classified			
5	107	Construction Work In Progress	103		
6		Total Property (Total Of Lines 2-5)		13,283,331	18,473,574
7	108	Less: Accumulated Provision for Depreciation of Service Company Property	104		
8	111	Less: Accumulated Provision for Amortization of Service Company Property			
9		Net Service Company Property (Total of Lines 6-8)		13,283,331	18,473,574
10		**Investments**			
11	123	Investment In Associate Companies	105		
12	124	Other Investments	105	87,670,648	69,332,588
13	128	Other Special Funds	105		
14		Total Investments (Total of Lines 11-13)		87,670,648	69,332,588
15		**Current And Accrued Assets**			
16	131	Cash			
17	134	Other Special Deposits			
18	135	Working Funds			
19	136	Temporary Cash Investments		603,158	754,623
20	141	Notes Receivable			
21	142	Customer Accounts Receivable			
22	143	Accounts Receivable		4,042,571	4,512,137
23	144	Less: Accumulated Provision for Uncollectible Accounts			
24	146	Accounts Receivable From Associate Companies	106	135,418,705	124,463,250
25	152	Fuel Stock Expenses Undistributed	107		
26	154	Materials And Supplies			
27	163	Stores Expense Undistributed	108		
28	165	Prepayments		92,248,781	75,587,104
29	171	Interest And Dividends Receivable			127,672
30	172	Rents Receivable			
31	173	Accrued Revenues			
32	174	Miscellaneous Current and Accrued Assets			
33	175	Derivative Instrument Assets	109		
34	176	Derivative Instrument Assets – Hedges			
35		Total Current and Accrued Assets (Total of Lines 16-34)		232,313,215	205,444,786
36		**Deferred Debits**			
37	181	Unamortized Debt Expense			
38	182.3	Other Regulatory Assets			
39	183	Preliminary Survey And Investigation Charges			
40	184	Clearing Accounts			
41	185	Temporary Facilities			
42	186	Miscellaneous Deferred Debits		196,256,206	197,472,631
43	188	Research, Development, or Demonstration Expenditures	110		
44	189	Unamortized loss on reacquired debt	111		
45	190	Accumulated Deferred Income Taxes		64,828,597	56,198,825
46		Total Deferred Debits (Total of Lines 37-45)		261,084,803	253,671,456
47		TOTAL ASSETS AND OTHER DEBITS (TOTAL OF LINES 9, 14, 35 and 46)		594,351,997	546,922,404

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
Xcel Energy Services Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2020

Schedule I - Comparative Balance Sheet (continued)

Line No.	Account Number (a)	Description (b)	Reference Page No. (c)	As of Dec 31 Current (d)	As of Dec 31 Prior (e)
48		**Proprietary Capital**			
49	201	Common Stock Issued	201	10	10
50	204	Preferred Stock Issued	201		
51	211	Miscellaneous Paid-In-Capital	201	(344,607)	(342,951)
52	215	Appropriated Retained Earnings	201		
53	216	Unappropriated Retained Earnings	201	2,690,013	2,690,013
54	219	Accumulated Other Comprehensive Income	201	(11,710,314)	(12,863,622)
55		Total Proprietary Capital (Total of Lines 49-54)		(9,364,898)	(10,516,550)
56		**Long-Term Debt**			
57	223	Advances From Associate Companies	202		
58	224	Other Long-Term Debt	202		
59	225	Unamortized Premium on Long-Term Debt			
60	226	Less: Unamortized Discount on Long-Term Debt-Debit			
61		Total Long-Term Debt (Total of Lines 57-60)			
62		Other Non-current Liabilities			
63	227	Obligations Under Capital Leases-Non-current		5,192,152	13,283,331
64	228.2	Accumulated Provision for Injuries and Damages			
65	228.3	Accumulated Provision For Pensions and Benefits		123,764,429	140,343,331
66	230	Asset Retirement Obligations			
67		Total Other Non-current Liabilities (Total of Lines 63-66)		128,956,581	153,626,662
68		**Current and Accrued Liabilities**			
69	231	Notes Payable			
70	232	Accounts Payable		189,826,579	191,227,808
71	233	Notes Payable to Associate Companies	203	100,700,000	71,500,000
72	234	Accounts Payable to Associate Companies	203		
73	236	Taxes Accrued		20,153,631	13,331,284
74	237	Interest Accrued		104,730	85,291
75	241	Tax Collections Payable		4,010,664	3,142,927
76	242	Miscellaneous Current and Accrued Liabilities	203	8,061,006	7,803,923
77	243	Obligations Under Capital Leases – Current		8,091,179	5,190,244
78	244	Derivative Instrument Liabilities			
79	245	Derivative Instrument Liabilities – Hedges			
80		Total Current and Accrued Liabilities (Total of Lines 69-79)		330,947,789	292,281,477
81		**Deferred Credits**			
82	253	Other Deferred Credits		110,736,520	82,896,812
83	254	Other Regulatory Liabilities			
84	255	Accumulated Deferred Investment Tax Credits			
85	257	Unamortized Gain on Reacquired Debt			
86	282	Accumulated deferred income taxes-Other property		2,244,566	2,055,390
87	283	Accumulated deferred income taxes-Other		30,831,439	26,578,613
88		Total Deferred Credits (Total of Lines 82-87)		143,812,525	111,530,815
89		**TOTAL LIABILITIES AND PROPRIETARY CAPITAL (TOTAL OF LINES 55, 61, 67, 80, AND 88)**		594,351,997	546,922,404

Name of Respondent Xcel Energy Services Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Resubmission Date (Mo, Da, Yr) / /	Year/Period of Report Dec 31, 2020

Schedule II - Service Company Property

1. Provide an explanation of Other Changes recorded in Column (f) considered material in a footnote.
2. Describe each construction work in progress on lines 18 through 30 in Column (b).

Line No.	Acct # (a)	Title of Account (b)	Balance at Beginning of Year (c)	Additions (d)	Retirements or Sales (e)	Other Changes (f)	Balance at End of Year (g)
1	301	Organization					
2	303	Miscellaneous Intangible Plant					
3	306	Leasehold Improvements					
4	389	Land and Land Rights					
5	390	Structures and Improvements					
6	391	Office Furniture and Equipment					
7	392	Transportation Equipment					
8	393	Stores equipment					
9	394	Tools, Shop and Garage Equipment					
10	395	Laboratory Equipment					
11	396	Power Operated Equipment					
12	397	Communications Equipment					
13	398	Miscellaneous Equipment					
14	399	Other Tangible Property					
15	399.1	Asset Retirement Costs					
16		**Total Service Company Property (Total of Lines 1-15)**					
17	107	**Construction Work in Progress:**					
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19							
20							
21							
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31		**Total Account 107 (Total of Lines 18-30)**					
32		**Total (Lines 16 and Line 31)**					

Name of Respondent Xcel Energy Services Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Resubmission Date (Mo, Da, Yr) / /	Year/Period of Report Dec 31, 2020

Schedule III – Accumulated Provision for Depreciation and Amortization of Service Company Property

1. Provide an explanation of Other Charges in Column (f) considered material in a footnote.

Line No.	Account Number (a)	Description (b)	Balance at Beginning of Year (c)	Additions Charged To Account 403-403.1 404-405 (d)	Retirements (e)	Other Changes Additions (Deductions) (f)	Balance at Close of Year (g)
1	301	Organization					
2	303	Miscellaneous Intangible Plant					
3	306	Leasehold Improvements					
4	389	Land and Land Rights					
5	390	Structures and Improvements					
6	391	Office Furniture and Equipment					
7	392	Transportation Equipment					
8	393	Stores equipment					
9	394	Tools, Shop and Garage Equipment					
10	395	Laboratory Equipment					
11	396	Power Operated Equipment					
12	397	Communications Equipment					
13	398	Miscellaneous Equipment					
14	399	Other Tangible Property					
15	399.1	Asset Retirement Costs					
16		**Total**					

Name of Respondent Xcel Energy Services Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Resubmission Date (Mo, Da, Yr) / /	Year/Period of Report Dec 31, 2020

Schedule IV – Investments

1. For other investments (Account 124) and other special funds (Account128), in a footnote state each investment separately, with description including the name of issuing company, number of shares held or principal investment amount.
2. For temporary cash investments (Account 136), list each investment separately in a footnote.
3. Investments less than $50,000 may be grouped, showing the number of items in each group.

Line No.	Account Number (a)	Title of Account (b)	Balance at Beginning of Year (c)	Balance at Close of Year (d)
1	123	Investment In Associate Companies		
2	124	Other Investments	69,332,588	87,670,648
3	128	Other Special Funds		
4	136	Temporary Cash Investments	754,623	603,158
5		(Total of Lines 1-4)	70,087,211	88,273,806

Name of Respondent	This Report is:	Resubmission Date (Mo, Da, Yr)	Year of Report
Xcel Energy Services Inc.	(1) X An Original (2) __ A Resubmission	/ /	2020

FOOTNOTE DATA

Schedule Page: 105 Line No.: 2 Column: d

FERC Account 124-Other Investments:

Funding vehicles for key man insurance and deferred compensation obligations.

2020	Pacific Life Insurance Co.	Security Life Insurance	Prudential Insurance Co.	Rabbi Trust	Hartford Insurance Co.	Total
Officer Survivor Benefit (OSB) Cash Surrender Value (CSV)	$ -	$ -	$ -	$ -	$ 2,192	$ 2,192
Premiums	236,803	18,439	77,453	-	-	332,695
CSV	11,403,290	495,933	1,401,482	78,874,861	-	92,175,566
Loans	(4,501,790)	(338,015)	-	-	-	(4,839,805)
Total	$ 7,138,303	$ 176,357	$ 1,478,935	$78,874,861	$ 2,192	$ 87,670,648

Schedule Page: 105 Line No.: 4 Column: d

FERC Account 136-Temporary Cash Investments:

The full amount represents December 31, 2020 excess cash balance which was held in a temporary cash investments.

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
Xcel Energy Services Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2020

Schedule V – Accounts Receivable from Associate Companies

1. List the accounts receivable from each associate company.
2. If the service company has provided accommodation or convenience payments for associate companies, provide in a separate footnote a listing of total payments for each associate company.

Line No.	Account Number (a)	Title of Account (b)	Balance at Beginning of Year (c)	Balance at Close of Year (d)
1	146	**Accounts Receivable From Associate Companies**		
2		**Associate Company:**		
3		Northern States Power Company, a Minnesota corporation (NSP-Minnesota)	52,995,339	60,054,777
4		Public Service Company of Colorado, a Colorado corporation (PSCo)	43,774,681	50,685,554
5		Southwestern Public Service Company, a New Mexico corporation (SPS)	19,262,332	16,864,349
6		Northern States Power Company, a Wisconsin corporation (NSP-Wisconsin)	9,052,099	8,711,975
7		Xcel Energy WYCO, Inc.	331,571	574,488
8		Nicollet Land Services, LLC		36,444
9		Seren Innovations, Inc.	2,842	29,369
10		Nicollet Project Holdings		25,408
11		Capital Services, LLC	15,716	20,294
12		Eloigne Company	(648)	19,649
13		Nicollet Holdings Company	7,547	10,708
14		Nicollet Projects I, LLC	44,741	10,001
15		Chippewa and Flambeau Improvement Company	3,874	4,812
16		Energy Impact Fund Investments, Inc.	2,822	4,604
17		1480 Welton, Inc.	3,774	4,447
18		Xcel Energy Performance Contracting, Inc.	2,441	4,114
19		PSR Investments, Inc.	2,188	2,444
20		Xcel Energy Wholesale Group, Inc.	1,836	1,449
21		WestGas Interstate, Inc.	1,147	1,425
22		e-prime, Inc.	58,774	1,424
23		Xcel Energy Ventures, Inc.	1,484	1,416
24		Xcel Energy Retail Holdings, Inc.	1,065	1,368
25		United Power & Land Company	209	1,288
26		Xcel Energy Markets Holdings, Inc.	272	1,222
27		Xcel Energy International, Inc.	686	1,122
28		Xcel Energy Transmission Holding Company, LLC	1,124	1,068
29		Xcel Energy Communications Group, Inc.	786	951
30		Xcel Energy West Transmission Company, LLC	694	779
31		Xcel Energy Southwest Transmission Company, LLC	729	768
32		Xcel Energy Transmission Development Company, LLC	29,350	741
33		Xcel Energy Ventures Holdings, Inc.	721	709
34		Clearwater Investments, Inc.	945	623
35		Quixxlin Corporation	300	300
36		Reddy Kilowatt Corporation	257	298
37		Quixx Corporation	5,898	144
38		Xcel Energy Investments	55	64
39		NSP Lands, Inc.	25	62

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
Xcel Energy Services Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2020

Schedule V – Accounts Receivable from Associate Companies (continued)

Line No.	Account Number (a)	Title of Account (b)	Balance at Beginning of Year (c)	Balance at Close of Year (d)
1	146	**Accounts Receivable From Associate Companies**		
2		**Associate Company:**		
3		MEC Holdings, LLC	893,313	
4		Xcel Energy, Inc.	(2,037,739)	(1,661,953)
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40	**Total**		**124,463,250**	**135,418,705**

Name of Respondent	This Report is:	Resubmission Date (Mo, Da, Yr)	Year of Report
Xcel Energy Services Inc.	(1) X An Original (2) __ A Resubmission	/ /	2020

FOOTNOTE DATA

Schedule Page: 106.1 Line No.: 4 Column: d

Xcel Energy Inc.:

This credit balance represents unsettled payments for the 401(k) and restricted stock units. The offsetting equity account for these items are recorded on Xcel Energy Inc. (the Holding Company). Xcel Energy Services, Inc. (the Service Company) debits an expense account and credits an intercompany A/R with the Holding Company. The conesponding entry on the Holding Company is a debit to an intercompany A/R with the Service Company and a credit to an equity account.

Schedule Page: 106.1 Line No.: 5 Column: d

2020 Convenience Payments

PSCo	$	16,728,006
NSP-Minnesota		16,055,301
SPS		5,156,727
Xcel Energy WYCO, Inc.		3,125,341
NSP-Wisconsin		3,044,174
Xcel Energy, Inc.		118,041
P.S.R. Investments, Inc		107,361
MEC Holdings, LLC		101,786
Seren Innovations, Inc.		54,745
Nicollet Project Holdings		25,611
Nicollet Projects I, LLC		20,589
Nicollet Land Services, LLC		20,000
Chippewa and Flambeau Improvement Company		12,988
Xcel Energy Performance Contracting, Inc.		5,531
WestGas Interstate, Inc.		2,725
Reddy Kilowatt Corporation		2,501
Eloigne Company		318
Capital Services, LLC		76
Total	$	44,581,821

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
Xcel Energy Services Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2020

Schedule VI – Fuel Stock Expenses Undistributed

1. List the amount of labor in Column (c) and expenses in Column (d) incurred with respect to fuel stock expenses during the year and indicate amount attributable to each associate company.
2. In a separate footnote, describe in a narrative the fuel functions performed by the service company.

Line No.	Account Number (a)	Title of Account (b)	Labor (c)	Expenses (d)	Total (e)
1	152	Fuel Stock Expenses Undistributed			
2		Associate Company:			
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40	**Total**				

Name of Respondent Xcel Energy Services Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Resubmission Date (Mo, Da, Yr) / /	Year/Period of Report Dec 31, 2020

Schedule VII – Stores Expense Undistributed

1. List the amount of labor in Column (c) and expenses in Column (d) incurred with respect to stores expense during the year and indicate amount attributable to each associate company.

Line No.	Account Number (a)	Title of Account (b)	Labor (c)	Expenses (d)	Total (e)
1	163	Stores Expense Undistributed	[redacted]	[redacted]	
2		Associate Company:			
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40	**Total**				

Name of Respondent Xcel Energy Services Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Resubmission Date (Mo, Da, Yr) / /	Year/Period of Report Dec 31, 2020

Schedule VIII - Miscellaneous Current and Accrued Assets

1. Provide detail of items in this account. Items less than $50,000 may be grouped, showing the number of items in each group.

Line No.	Account Number (a)	Title of Account (b)	Balance at Beginning of Year (c)	Balance at Close of Year (d)
1	174	**Miscellaneous Current and Accrued Assets**	[redacted]	[redacted]
2		**Item List:**	[redacted]	[redacted]
3				
4				
5				
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40	**Total**			

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
Xcel Energy Services Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2020

Schedule IX - Miscellaneous Deferred Debits

1. Provide detail of items in this account. Items less than $50,000 may be grouped, showing the number of items in each group.

Line No.	Account Number (a)	Title of Account (b)	Balance at Beginning of Year (c)	Balance at Close of Year (d)
1	186	**Miscellaneous Deferred Debits**		
2		**Items List:**		
3		Post Retirement Benefits	195,871,991	194,656,308
4		Life Insurance Premium	1,600,000	1,600,000
5		Other Miscellaneous Deferred Debits	640	(102)
6				
7				
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40	**Total**		**197,472,631**	**196,256,206**

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
Xcel Energy Services Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2020

Schedule X - Research, Development, or Demonstration Expenditures

1. Describe each material research, development, or demonstration project that incurred costs by the service corporation during the year. Items less than $50,000 may be grouped, showing the number of items in each group.

Line No.	Account Number (a)	Title of Account (b)	Amount (c)
1	188	**Research, Development, or Demonstration Expenditures**	
2		**Project List:**	
3			
4			
5			
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40	**Total**		

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
Xcel Energy Services Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2020

Schedule XI - Proprietary Capital

1. For miscellaneous paid-in capital (Account 211) and appropriate retained earnings (Account 215), classify amounts in each account, with a brief explanation, disclosing the general nature of transactions which give rise to the reported amounts.
2. For the unappropriated retained earnings (Account 216), in a footnote, give particulars concerning net income or (loss) during the year, distinguishing between compensation for the use of capital owed or net loss remaining from servicing nonassociates per the General Instructions of the Uniform System of Accounts. For dividends paid during the year in cash or otherwise, provide rate percentages, amount of dividend, date declared and date paid.

Line No.	Account Number (a)	Title of Account (b)	Description (c)	Amount (d)
1	201	Common Stock Issued	Number of Shares Authorized	1,000
2			Par or Stated Value per Share	0.01
3			Outstanding Number of Shares	1,000
4			Close of Period Amount	10
5		Preferred Stock Issued	Number of Shares Authorized	
6			Par or Stated Value per Share	
7			Outstanding Number of Shares	
8			Close of Period Amount	
9	211	Miscellaneous Paid-In Capital		(344,607)
10	215	Appropriated Retained Earnings		
11	219	Accumulated Other Comprehensive Income		(117,104)
12	216	Unappropriated Retained Earnings	Balance at Beginning of Year	2,690,013
13			Net Income or (Loss)	
14			Dividend Paid	
15			Balance at Close of Year	2,690,013

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
Xcel Energy Services Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2020

Schedule XII – Long Term Debt

1. For the advances from associate companies (Account 223), describe in a footnote the advances on notes and advances on open accounts. Names of associate companies from which advances were received shall be shown under the class and series of obligation in Column (c).
2. For the deductions in Column (h), please give an explanation in a footnote.
3. For other long-term debt (Account 224), list the name of the creditor company or organization in Column (b).

Line No.	Account Number (a)	Title of Account (b)	Term of Obligation Class & Series of Obligation (c)	Date of Maturity (d)	Interest Rate (e)	Amount Authorized (f)	Balance at Beginning of Year (g)	Additions Deductions (h)	Balance at Close of Year (i)
1	223	Advances from Associate Companies							
2		Associate Company:							
3									
4									
5									
6									
7									
8									
9									
10									
11									
12									
13		TOTAL							
14	224	Other Long-Term Debt							
15		List Creditor:							
16									
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18									
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27									
28		TOTAL							

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Schedule XIII – Current and Accrued Liabilities

1. Provide the balance of notes and accounts payable to each associate company (Accounts 233 and 234).
2. Give description and amount of miscellaneous current and accrued liabilities (Account 242). Items less than $50,000 may be grouped, showing the number of items in each group.

Line No.	Account Number (a)	Title of Account (b)	Balance at Beginning of Year (c)	Balance at Close of Year (d)
1	233	Notes Payable to Associates Companies	71,500,000	100,700,000
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24	234	Accounts Payable to Associate Companies		
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41	242	Miscellaneous Current and Accrued Liabilities	7,803,923	8,061,006
42				
43				
44				
45				
46				
47				
48				
49				
50		(Total)	79,303,923	108,761,006

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FOOTNOTE DATA

Schedule Page: 203   Line No.: 1   Column: d

FERC Account 233-Notes Payable to Associate Companies

The 2020 balance represents intercompany borrowings with Xcel Energy, Inc.

Schedule Page: 203   Line No.: 41   Column: d

FERC Account 242-Miscellaneous Current and Accrued Liabilities

The 2019 balance represents the current benefit obligation for a non-qualified pension plan and retiree medical and other miscellaneous liability accruals.

Non-qualified pension plan	$	6,488,000
Retiree Medical		1,438,000
Litigation & Misc Accruals		135,006
Total	**$**	**8,061,006**

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Schedule XIV- Notes to Financial Statements			

1. Use the space below for important notes regarding the financial statements or any account thereof.
2. Furnish particulars as to any significant contingent assets or liabilities existing at the end of the year.
3. Furnish particulars as to any significant increase in services rendered or expenses incurred during the year.
4. Furnish particulars as to any amounts recorded in Account 434, Extraordinary Income, or Account 435, Extraordinary Deductions.
5. Notes relating to financial statements shown elsewhere in this report may be indicated here by reference.
6. Describe the annual statement supplied to each associate service company in support of the amount of interest on borrowed capital and compensation for use of capital billed during the calendar year. State the basis for billing of interest to each associate company. If a ratio, describe in detail how ratio is computed. If more than one ratio explain the calculation. Report the amount of interest borrowed and/or compensation for use of capital billed to each associate company.

ANNUAL REPORT OF XCEL ENERGY SERVICES INC.

For the Years Ended December 31, 2020 and 2019

Schedule XIV - NOTES TO FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Business and System of Accounts — Xcel Energy Services Inc. (XES or the Company) is a wholly owned subsidiary of Xcel Energy Inc. (Xcel Energy). XES provides Northern States Power Company, a Minnesota corporation (NSP-Minnesota), Northern States Power Company, a Wisconsin corporation (NSP-Wisconsin), Public Service Company of Colorado (PSCo) and Southwestern Public Service Company (SPS) and other subsidiaries of Xcel Energy with a variety of administrative, management, engineering, construction and corporate support services at cost. XES began operations effective April 2, 1997 doing business as New Century Energy. All of XES' accounting records conform to the Federal Energy Regulatory Commission (FERC) uniform system of accounts or to systems required by various state regulatory commissions, which are the same in all material respects.

Basis of Accounting — The accompanying financial statements were prepared in accordance with the accounting requirements of the FERC as set forth in the Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than Generally Accepted Accounting Principles (GAAP). The following areas represent the significant differences between the Uniform System of Accounts and GAAP:

- Accumulated deferred income taxes are shown as long-term assets and liabilities at their gross amounts in the FERC presentation, in contrast to the GAAP presentation as net long-term assets and liabilities.
- Unrecognized tax benefits are recorded for temporary differences in accounts established for accumulated deferred income taxes in the FERC presentation, in contrast to the GAAP presentation as taxes accrued and noncurrent other liabilities.
- Various expenses such as donations, lobbying, and other non-regulatory expenses are presented as other income and deductions for the FERC presentation and reported as operating expenses for the GAAP presentation.
- Income tax expense is shown as a component of operating expenses in the FERC presentation, in contrast to the GAAP presentation as a below-the-line deduction from operating income.

Subsequent Events **—** Management has evaluated the impact of events occurring after Dec. 31, 2021 up to Feb. 17, 2021, the date Xcel Energy's GAAP financial statements were issued and has updated such evaluation for disclosure purposes through the date of filing this report. These statements contain all necessary adjustments and disclosures resulting from these evaluations.

Use of Estimates — In recording transactions and balances resulting from business operations, XES uses estimates based on the best information available. The recorded estimates are revised when better information becomes available or when actual amounts can be determined. Those revisions can affect operating results.

Benefit Plans and Other Postretirement Benefits — Xcel Energy maintains pension and postretirement benefit plans for eligible employees. Recognizing the cost of providing benefits and measuring the projected benefit obligation of these plans under applicable accounting guidance requires management to make various assumptions and estimates.

Based on the regulatory recovery mechanisms of Xcel Energy's utility subsidiaries, certain unrecognized actuarial gains and losses and unrecognized prior service costs or credits are recorded as regulatory assets and liabilities, rather than other comprehensive income.

Leases — XES evaluates a variety of contracts for lease classification at inception, including rental arrangements for office space,

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vehicles and equipment. Contracts determined to contain a lease because of per unit pricing that is other than fixed or market price, terms regarding the use of a particular asset, and other factors are evaluated further to determine if the arrangement is a capital lease.

Income Taxes — The Company's operations are included in the consolidated federal income tax return of Xcel Energy. The allocation of income tax consequences to the Company is calculated under a parent company policy which provides that benefits or liabilities created by the Company, computed on a separate return basis, will be allocated to (and paid to or by) the Company to the extent the benefits are usable or additional liabilities are incurred in Xcel Energy's consolidated tax returns. Deferred taxes are provided on temporary differences between the financial accounting and tax bases of assets and liabilities using the tax rates that are in effect at the balance sheet date (see Note 6).

Cash and Cash Equivalents — XES considers investments in certain instruments with a remaining maturity of three months or less at the time of purchase, to be cash equivalents.

***Accounts Receivable* —** Accounts receivable are stated at the actual billed amount.

2. Common Stock

XES has authorized the issuance of common stock.

Common Shares Authorized	Par Value
1,000	$ 0.01

At Dec. 31, 2020 and 2019, all shares of common stock were issued and held by Xcel Energy.

3. Borrowings and Other Financing Instruments

Money Pool – Xcel Energy has established a utility money pool arrangement with NSP-Minnesota, PSCo, and SPS. The utility money pool, administered by XES, allows for short-term investments in and borrowings between the participating utility subsidiaries. Xcel Energy may make investments in the participating utility subsidiaries at market-based interest rates; however, the money pool arrangement does not allow the participating utility subsidiaries to make investments in Xcel Energy.

The Board of Directors has authorized the Company to borrow directly from Xcel Energy. At Dec. 31, intercompany borrowings outstanding and the weighted average interest rate were as follows:

(Amounts in Thousands of Dollars, Except Interest Rates)	Twelve Months Ended Dec. 31, 2020	Twelve Months Ended Dec. 31, 2019
Borrowing limit	$ 300,000	$ 300,000
Intercompany borrowings outstanding at period end	100,700	71,500
Average amount outstanding	143,271	148,075
Maximum amount outstanding	255,900	246,000
Weighted average interest rate, computed on a daily basis	1.28 %	2.75 %
Weighted average interest rate at period end	0.19	2.41

4. Commitments and Contingencies

Leases — XES leases a variety of equipment and facilities used in the normal course of business. Total expenses under operating lease obligations for XES were approximately $5.8 million in 2020 and 2019.

Future commitments under operating leases are as follows:

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(Thousands of Dollars)	Total Operating Leases
2021	$ 8,438
2022	1,078
2023	3,882
2024	324
2025	145
Thereafter	24
Total minimum obligation	13,891
Interest component of obligation	(608)
Present value of minimum obligation	13,283
Less current portion	(8,091)
Noncurrent operating lease obligation	$ 5,192
Weighted-average remanining lease term in years	1.7

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Technology Agreements —Xcel Energy has several contracts for information technology services that extend through 2022. The contracts are cancelable, although there are financial penalties for early termination. Xcel Energy capitalized or expensed $110 million, $101 million and $127 million associated with these contracts in 2020, 2019 and 2018, respectively.

Committed minimum payments under these obligations are $33 million in 2021 and $15 million in 2022.

5. Benefit Plans and Other Postretirement Benefits

Pension and other postretirement disclosures below represent Xcel Energy consolidated information unless specifically identified as being attributable to XES. Consistent with the process for rate recovery of pension and postretirement benefits for its employees, XES accounts for its participation in, and related costs of, pension and other postretirement benefit plans sponsored by Xcel Energy as multiple employer plans. XES is responsible for its share of cash contributions, plan costs and obligations and is entitled to its share of plan assets; accordingly, XES accounts for its pro rata share of these plans, including pension expenses and contributions, resulting in accounting consistent with that of a single employer plan exclusively for XES employees.

The plans invest in various instruments which are disclosed under the accounting guidance for fair value measurements which establishes a hierarchical framework for disclosing the observability of the inputs utilized in measuring fair value. The three levels in the hierarchy and examples of each level are as follows:

Level 1 — Quoted prices are available in active markets for identical assets as of the reporting date. The types of assets included in Level 1 are highly liquid and actively traded instruments with quoted prices.

Level 2 — Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reporting date. The types of assets 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 included in Level 3 are those with inputs requiring significant management judgment or estimation.

Pension Benefits

Xcel Energy, which includes XES, has several noncontributory, defined benefit pension plans that cover almost all employees. Generally, benefits are based on a combination of years of service, the employee's average pay and, in some cases, social security benefits. Xcel Energy and XES' policy is to fully fund into an external trust the actuarially determined pension costs recognized for ratemaking and financial reporting purposes, subject to the limitations of applicable employee benefit and tax laws.

In addition to the qualified pension plans, Xcel Energy maintains a supplemental executive retirement plan (SERP) and a nonqualified pension plan. The SERP is maintained for certain executives that were participants in the plan in 2008, when the SERP was closed to new participants. The nonqualified pension plan provides unfunded, nonqualified benefits for compensation that is in excess of the limits applicable to the qualified pension plans. The total obligations of the SERP and nonqualified plan as of Dec. 31, 2020 and 2019 for XES were $34.1 million and $28.7 million, respectively. XES recognized net benefit cost for financial reporting for the SERP and nonqualified plans of $3.0 million in 2020 and $2.3 million in 2019. Benefits for these unfunded plans are paid out of Xcel Energy's consolidated operating cash flows.

In 2016, Xcel Energy established rabbi trusts to provide partial funding for future distributions of the SERP and its deferred compensation plan, supplemented by Xcel Energy's consolidated operating cash flows as determined necessary. Also, in 2016, Xcel Energy amended the deferred compensation plan to provide eligible participants the ability to diversify deferred settlements of equity awards, other than time-based equity awards, into various fund options.

Xcel Energy and XES base their investment-return assumption on expected long-term performance for each of the investment types included in its pension asset portfolio. Xcel Energy and XES consider the historical returns achieved by its asset portfolio over the past 20-year or longer period, as well as the long-term return levels projected and recommended by investment experts. Investment returns were above the assumed levels of 6.87 percent in 2020 and 2019. Xcel Energy and XES continually review their pension assumptions. In 2021, Xcel Energy and XES will use an investment return assumption of 6.49 percent. The pension cost

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determination assumes a forecasted mix of investment types over the long-term.

The assets are invested in a portfolio according to Xcel Energy and XES' return, liquidity and diversification objectives to provide a source of funding for plan obligations and minimize the necessity of contributions to the plan, within appropriate levels of risk. The principal mechanism for achieving these objectives is the projected allocation of assets to selected asset classes, given the long-term risk, return, and liquidity characteristics of each particular asset class. There were no significant concentrations of risk in any particular industry, index, or entity. Market volatility can impact even well-diversified portfolios and significantly affect the return levels achieved by pension assets in any year.

The following table presents the target pension asset allocations for Xcel Energy at Dec. 31 for the upcoming year:

	2020	2019
Domestic and international equity securities	35 %	37 %
Long-duration fixed income securities	35	30
Short-to-intermediate fixed income securities	13	14
Alternative investments	15	17
Cash	2	2
Total	100 %	100 %

The 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 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. The aggregate projected asset allocation presented in the table above for the master pension trust results from the plan-specific strategies.

Pension Plan Assets

The following tables present, for each of the fair value hierarchy levels, Xcel Energy's pension plan assets that are measured at fair value as of Dec. 31, 2020 and 2019:

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	Dec. 31, 2020				
(Millions of Dollars)	Level 1	Level 2	Level 3	Investments Measured at NAV	Total
Cash equivalents	$ 209	$ -	$ -	$ -	$ 209
Commingled funds	1,462	-	-	1,115	2,577
Debt Securities	-	714	4	-	718
Equity Securities	77	-	-	-	77
Other	13	5	-	-	18
Total	$ 1,761	$ 719	$ 4	$ 1,115	$ 3,599

	Dec. 31, 2019				
(Millions of Dollars)	Level 1	Level 2	Level 3	Investments Measured at NAV	Total
Cash equivalents	$ 145	$ -	$ -	$ -	$ 145
Commingled funds	1,408	-	-	1,031	2,439
Debt Securities	-	645	4	-	649
Equity Securities	86	-	-	-	86
Other	(120)	5	-	(20)	(135)
Total	$ 1,519	$ 650	$ 4	$ 1,011	$ 3,184

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Benefit Obligations — A comparison of the actuarially computed pension benefit obligation and plan assets for Xcel Energy is presented in the following table:

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(Thousands of Dollars)	2020	2019
Accumulated Benefit Obligation at Dec. 31	$ 3,693,084	$ 3,464,677
Change in Projected Benefit Obligation:		
Obligation at Jan. 1	$ 3,700,869	$ 3,474,403
Service cost	95,335	85,992
Interest cost	125,260	144,283
Plan amendments	-	981
Actuarial loss (gain)	327,491	275,754
Benefit Payments [(a)]	(284,636)	(280,544)
Obligation at Dec. 31	$ 3,964,319	$ 3,700,869

(Thousands of Dollars)	2020	2019
Change in Fair Value of Plan Assets:		
Fair value of plan assets at Jan. 1	$ 3,184,324	$ 2,742,272
Actual return (loss) on plan assets	549,686	568,177
Employer contributions	150,000	154,419
Benefit payments	(284,636)	(280,544)
Fair value of plan assets at Dec. 31	$ 3,599,374	$ 3,184,324
Funded Status of Plans at Dec. 31:		
Funded status [(b)]	$ (364,945)	$ (516,545)

[(a)] Includes approximately $0 million in 2020 and $20 million in 2019 of lump-sum benefit payments used in the settlement of a charge.

[(b)] Amounts are recognized in noncurrent liabilities on Xcel Energy's consolidated balance sheets.

(Thousands of Dollars)	2020	2019
XES Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:		
Net loss	$ 186,472	$ 195,582
Prior service cost	(8,322)	(9,307)
Total	$ 178,150	$ 186,275

(Thousands of Dollars)	2020	2019
XES Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost Have Been Recorded as Follows Based Upon Expected Recovery in Rates:		
Miscellanous deferred debits	$ 173,614	$ 176,319
Accumulated deferred income taxes	1,182	2,575
Net-of-tax accumulated other comprehensive income	3,354	7,381
Total	$ 178,150	$ 186,275
XES accumulated provision for pensions and benefits	$ 68,793	$ 91,002
Measurement date	Dec. 31, 2020	Dec. 31, 2019

	2020	2019
Significant Assumptions Used to Measure Benefit Obligations:		
Discount rate for year-end valuation	2.71 %	3.49 %
Expected average long-term increase in compensation level	3.75	3.75
Mortality table	PRI - 2012	PRI - 2012

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Cash Flows — Cash funding requirements can be impacted by changes to actuarial assumptions, actual asset levels and other calculations prescribed by the funding requirements of income tax and other pension-related regulations. Required contributions were made in 2018 through 2021 to meet minimum funding requirements. Total voluntary and required pension funding contributions across all four of Xcel Energy's pension plans were as follows:

- $125 million in January 2021;
- $150 million in 2020;
- $154 million in 2019; and
- $150 million in 2018.

For future years, Xcel Energy anticipates contributions will be made as necessary.

Plan Amendments — Xcel Energy amended the Xcel Energy Pension Plan and Xcel Energy Inc. Non-bargaining Pension Plan (South) in 2017 to reduce supplemental benefits for non-bargaining participants as well as to allow the transfer of a portion of nonqualified pension obligations into the qualified plans.

In 2020 and 2019, there were no plan amendments made which affected the projected benefit obligation.

Benefit Costs — The components of Xcel Energy's net periodic pension cost were:

(Thousands of Dollars)	2020	2019
Service cost	$ 95,335	$ 85,992
Interest cost	125,260	144,283
Expected return on plan assets	(208,122)	(203,211)
Amortization of prior service credit	(3,996)	(4,643)
Amortization of net loss	99,396	88,180
Settlement charge	-	6,160
Net periodic pension cost	107,873	116,761
Costs not recognized due to effects of regulation	8,791	589
Net benefit cost recognized for financial reporting	$ 116,664	$ 117,350
XES:		
Net periodic pension cost	$ 20,625	$ 21,759

	2020	2019
Significant Assumptions Used to Measure Costs:		
Discount rate	3.49 %	4.31 %
Expected average long-term increase in compensation level	3.75	3.75
Expected average long-term rate of return on assets	6.87	6.87

Pension costs include an expected return impact for the current year that may differ from actual investment performance in the plan. The return assumption used for 2020 pension cost calculations is 6.87 percent. The pension cost calculation uses a market-related valuation of pension assets. Xcel Energy uses a calculated value method to determine the market-related value of the plan assets. The market-related value is determined by adjusting the fair market value of assets at the beginning of the year to reflect the investment gains and losses (the difference between the actual investment return and the expected investment return on the market related value) during each of the previous five years at the rate of 20 percent per year. As these differences between the actual investment returns and the expected investment returns are incorporated into the market-related value, the differences are recognized in pension cost over the expected average remaining years of service for active employees, which was approximately 13 years in 2020.

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Defined Contribution Plans

Xcel Energy, which includes XES, maintains 401(k) and other defined contribution plans that cover substantially all employees. Total expense to these plans was approximately $42 million in 2020 and $39 million in 2019. XES' portion of that expense was approximately $13 million in 2020 and $12 million in 2019.

Postretirement Health Care Benefits

Xcel Energy, which includes XES, has a contributory health and welfare benefit plan that provides health care and death benefits to certain retirees.

***Plan Assets* —** Certain state agencies that regulate Xcel Energy's utility subsidiaries also have issued guidelines related to the funding of postretirement benefit costs. These assets are invested in a manner consistent with the investment strategy for the pension plan.

The following table presents the target postretirement asset allocations for Xcel Energy at Dec. 31 for the upcoming year:

	2020	2019
Domestic and international equity securities	15 %	15 %
Short-to-intermediate fixed income securities	72	72
Alternative investments	9	9
Cash	4	4
Total	100 %	100 %

Xcel Energy and XES bases its investment-return assumption for the postretirement health care fund assets on expected long-term performance for each of the investment types included in its asset portfolio. The 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 projected 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 particular industry, index, or entity. Market volatility can impact even well-diversified portfolios and significantly affect the return levels achieved by postretirement health care assets in any year.

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The following tables present, for each of the fair value hierarchy levels, Xcel Energy's postretirement benefit plan assets that are measured at fair value as of Dec. 31, 2020 and 2019:

	Dec. 31, 2020				
(Millions of Dollars)	Level 1	Level 2	Level 3	Measured at NAV	Total
Cash equivalents	$ 27	$ -	$ -	$ -	$ 27
Insurance contracts	-	50	-	-	50
Commingled Funds	72	-	-	69	141
Debt Securities	-	232	-	-	232
Other	-	2	-	-	2
Total	$ 99	$ 284	$ -	$ 69	$ 452

	Dec. 31, 2019				
(Millions of Dollars)	Level 1	Level 2	Level 3	Investments Measured at NAV	Total
Cash equivalents	$ 23	$ -	$ -	$ -	$ 23
Insurance contracts	-	51	-	-	51
Commingled Funds	69	-	-	76	145
Debt Securities	-	228	1	-	229
Other	-	1	-	-	1
Total	$ 92	$ 280	$ 1	$ 76	$ 449

No assets were transferred in or out of Level 3 for 2020. Immaterial assets were transferred in or out of Level 3 for 2019.

Benefit Obligations — A comparison of the actuarially computed benefit obligation and plan assets for Xcel Energy is presented in the following table:

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(Thousands of Dollars)	2020	2019
Change in Projected Benefit Obligation:		
Obligation at Jan. 1	$ 547,575	$ 541,715
Service cost	1,517	1,553
Interest cost	18,277	22,464
Medicare subsidy reimbursements	434	1,683
Plan participants' contributions	8,046	7,900
Actuarial loss (gain)	50,030	19,152
Benefit payments	(51,489)	(46,892)
Obligation at Dec. 31	$ 574,390	$ 547,575

(Thousands of Dollars)	2020	2019
Change in Fair Value of Plan Assets:		
Fair value of plan assets at Jan. 1	$ 449,410	$ 416,978
Actual return (loss) on plan assets	35,220	56,215
Plan participants' contributions	8,046	7,900
Employer contributions	11,101	15,209
Benefit payments	(51,489)	(46,892)
Fair value of plan assets at Dec. 31	$ 452,288	$ 449,410

(Thousands of Dollars)	2020	2019
Funded Status of Plans at Dec. 31:		
Funded status	$ (122,102)	$ (98,165)
Miscellaneous deferred debits	(7,224)	(5,986)
Accumulated provision for pensions and benefits	(120,985)	(113,056)
Net postretirement amounts recognized on balance sheet	$ (128,209)	$ (119,042)

(Thousands of Dollars)	2020	2019
XES Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:		
Net loss	$ 17,275	$ 16,685
Prior service credit	(676)	(1,041)
Total	$ 16,599	$ 15,644

(Thousands of Dollars)	2020	2019
XES Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost Have Been Recorded as Follows Based Upon Expected Recovery in Rates:		
Miscellaneous deferred debits	$ 15,081	$ 14,187
Accumulated deferred income taxes	394	378
Net-of-tax accumulated other comprehensive income	1,124	1,079
Total	$ 16,599	$ 15,644
XES accumulated provision for pensions and benefits	$ 28,697	$ 27,894
Measurement date	Dec. 31, 2020	Dec. 31, 2019

	2020	2019
Significant Assumptions Used to Measure Benefit Obligations:		
Discount rate for year-end valuation	2.65 %	3.47 %
Mortality table	PRI-2012	PRI-2012
Health care costs trend rate - initial: Pre-65	5.50 %	6.00 %
Health care costs trend rate - initial: Post-65	5.00 %	5.10 %

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As of Dec. 31, 2020, the initial medical trend cost claim assumptions for Pre-65 was 5.5% and Post-65 was 5.0%. The ultimate trend assumption remained at 4.5% for both Pre-65 and Post-65 claims costs. Xcel Energy bases its medical trend assumption on the long-term cost inflation expected in the health care market, considering the levels projected and recommended by industry experts, as well as recent actual medical cost experienced by Xcel Energy's retiree medical plan.

Cash Flows **—** The postretirement health care plans have no funding requirements under income tax and other retirement-related regulations other than fulfilling benefit payment obligations, when claims are presented and approved under the plans. Additional cash funding requirements are prescribed by certain state and federal rate regulatory authorities. Xcel Energy, which includes XES, contributed $11 million, $15 million, and $11 million during 2020, 2019, and 2018, respectively, to the postretirement health care plans. Xcel Energy expects to contribute approximately $10 million during 2021.

Plan Amendments **—** In 2020 and 2019, there were no plan amendments made which affected the benefit obligation.

Benefit Costs — The components of Xcel Energy's net periodic postretirement benefit cost were:

(Thousands of Dollars)	2020	2019
Service cost	$ 1,517	$ 1,553
Interest cost	18,277	22,464
Expected return on plan assets	(19,516)	(21,231)
Amortization of prior service credit	(7,919)	(9,909)
Amortization of net loss	3,272	5,074
Net periodic postretirement benefit credit	$ (4,369)	$ (2,049)
XES:		
Net periodic postretirement benefit cost recognized	1,197	1,253

	2020	2019
Significant Assumptions Used to Measure Costs:		
Discount rate	3.47 %	4.32 %
Expected average long-term rate of return on assets	4.50	5.30

Name of Respondent	This Report is:	Resubmission Date (Mo, Da, Yr)	Year of Report
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Schedule XIV- Notes to Financial Statements

Projected Benefit Payments

The following table lists Xcel Energy's projected benefit payments for the pension and postretirement benefit plans:

(Thousands of Dollars)	Projected Pension Benefit Payments	Gross Projected Postretirement Health Care Benefit Payments	Expected Medicare Part D Subsidies	Net Projected Postretirement Health Care Benefit Payments
2021	$ 304,498	$ 43,869	$ 1,971	$ 41,898
2022	282,199	42,819	2,059	40,760
2023	273,542	41,916	2,139	39,777
2024	264,367	40,853	2,212	38,641
2025	258,831	39,412	2,286	37,126
2026-2030	1,193,360	175,437	12,118	163,319

6. Income Taxes

The components of income tax expense for the years ending Dec. 31 were as follows:

(Thousands of Dollars)	2020	2019
Current federal tax expense	$ 10,660	$ 3,581
Current state tax expense	4,253	1,956
Current change in unrecognized tax expense	1,166	985
Deferred federal tax benefit	(3,425)	520
Deferred state tax benefit	(1,162)	202
Total income tax expense	$ 11,492	$ 7,244

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. The following reconciles such differences for the years ending Dec. 31:

	2020	2019
Federal statutory rate	21 %	21 %
State income taxes, net of federal income tax benefit	5	5
Increases (decreases) in tax from:		
Resolutions of income tax audit and other	11	13
Texas margin tax, net of federal tax effect	7	11
Executive officer non-deductible compensation	53	48
Non-deductible business meals	3	5
Insurance fund income	-	(2)
Other	-	(1)
Effective income tax rate	100 %	100 %

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Schedule XIV- Notes to Financial Statements

The components of the accumulated deferred income taxes at Dec. 31 were as follows:

(Thousands of Dollars)	2020	2019
Deferred tax liabilities:		
Employee benefits	$ 26,949	$ 21,952
Operating lease assets	3,415	4,753
Differences between book and tax bases of property	2,245	2,055
Other	467	(126)
Total deferred tax liabilities	$ 33,076	$ 28,634
Deferred tax assets:		
Employee benefits	$ 60,684	$ 50,049
Operating lease assets	3,415	4,753
Other	730	1,397
Total deferred tax assets	$ 64,829	$ 56,199
Net deferred tax asset	$ (31,753)	$ (27,565)

7. Financial Instruments

In June 2016, XES established rabbi trusts to provide partial funding for future distributions of its supplemental executive retirement plan and deferred compensation plan. The following table presents the cost and fair value of the assets held in rabbi trusts at Dec. 31, 2020 and 2019:

	Dec. 31, 2020				
		Fair Value			
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Rabbi Trusts [(a)]					
Cash equivalents	$ 30	$ 30	$ -	$ -	$ 30
Mutual funds	41	49	-	-	49
Total	$ 71	$ 79	$ -	$ -	$ 79

	Dec. 31, 2019				
		Fair Value			
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Rabbi Trusts [(a)]					
Cash equivalents	$ 15	$ 15	$ -	$ -	$ 15
Mutual funds	39	45	-	-	45
Total	$ 54	$ 60	$ -	$ -	$ 60

(a) As of Dec. 31, 2020 and 2019, there were no financial instruments for which carrying amount did not equal fair value.

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Schedule XV- Comparative Income Statement

Line No.	Account Number (a)	Title of Account (b)	Current Year (c)	Prior Year (d)
1		**SERVICE COMPANY OPERATING REVENUES**		
2	400	Service Company Operating Revenues	1,483,039,185	1,378,715,448
3		**SERVICE COMPANY OPERATING EXPENSES**		
4	401	Operation Expenses	913,958,411	866,602,358
5	402	Maintenance Expenses	15,420,000	15,765,952
6	403	Depreciation Expenses		
7	403.1	Depreciation Expense for Asset Retirement Costs		
8	404	Amortization of Limited-Term Property		
9	405	Amortization of Other Property		
10	407.3	Regulatory Debits		
11	407.4	Regulatory Credits		
12	408.1	Taxes Other Than Income Taxes, Operating Income	23,342,663	20,444,919
13	409.1	Income Taxes, Operating Income	(11,412,550)	(7,244,174)
14	410.1	Provision for Deferred Income Taxes, Operating Income		
15	411.1	Provision for Deferred Income Taxes – Credit , Operating Income		
16	411.4	Investment Tax Credit, Service Company Property		
17	411.6	Gains from Disposition of Service Company Plant		
18	411.7	Losses from Disposition of Service Company Plant		
19	411.10	Accretion Expense		
20	412	Costs and Expenses of Construction or Other Services	516,508,842	460,565,069
21	416	Costs and Expenses of Merchandising, Jobbing, and Contract Work		
22		TOTAL SERVICE COMPANY OPERATING EXPENSES (Total of Lines 4-21)	1,457,817,366	1,356,134,124
23		NET SERVICE COMPANY OPERATING INCOME (Total of Lines 2 less 22)	25,221,819	22,581,324
24		**OTHER INCOME**		
25	418.1	Equity in Earnings of Subsidiary Companies		
26	419	Interest and Dividend Income	3,872,690	8,623,772
27	419.1	Allowance for Other Funds Used During Construction		
28	421	Miscellaneous Income or Loss		
29	421.1	Gain on Disposition of Property		
30		**TOTAL OTHER INCOME (Total of Lines 25-29)**	3,872,690	8,623,772
31		**OTHER INCOME DEDUCTIONS**		
32	421.2	Loss on Disposition of Property		
33	425	Miscellaneous Amortization		
34	426.1	Donations	594,673	8,484,282
35	426.2	Life Insurance	(156,612)	(639,825)
36	426.3	Penalties	12,047	16,142
37	426.4	Expenditures for Certain Civic, Political and Related Activities	2,129,188	2,205,013
38	426.5	Other Deductions	481,051	829,263
39		**TOTAL OTHER INCOME DEDUCTIONS (Total of Lines 32-38)**	3,060,347	10,894,875
40		**TAXES APPLICABLE TO OTHER INCOME AND DEDUCTIONS**		

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Schedule XV- Comparative Income Statement (continued)

Line No.	Account Number (a)	Title of Account (b)	Current Year (c)	Prior Year (d)
41	408.2	Taxes Other Than Income Taxes, Other Income and Deductions	158,528	536,489
42	409.2	Income Taxes, Other Income and Deductions	27,490,974	13,766,184
43	410.2	Provision for Deferred Income Taxes, Other Income and Deductions	(4,586,896)	722,160
44	411.2	Provision for Deferred Income Taxes – Credit, Other Income and Deductions		
45	411.5	Investment Tax Credit, Other Income Deductions		
46		**TOTAL TAXES APPLICABLE TO OTHER INCOME AND DEDUCTIONS (Total of Lines 41-45)**	23,062,606	15,024,833
47		**INTEREST CHARGES**		
48	427	Interest on Long-Term Debt		
49	428	Amortization of Debt Discount and Expense		
50	429	(less) Amortization of Premium on Debt- Credit		
51	430	Interest on Debt to Associate Companies	2,563,524	5,137,913
52	431	Other Interest Expense	408,032	147,475
53	432	(less) Allowance for Borrowed Funds Used During Construction-Credit		
54		**TOTAL INTEREST CHARGES (Total of Lines 48-53)**	2,971,556	5,285,388
55		**NET INCOME BEFORE EXTRAORDINARY ITEMS (Total of Lines 23, 30, minus 39, 46, and 54)**		
56		**EXTRAORDINARY ITEMS**		
57	434	Extraordinary Income		
58	435	(less) Extraordinary Deductions		
59		**Net Extraordinary Items (Line 57 less Line 58)**		
60	409.4	(less) Income Taxes, Extraordinary		
61		**Extraordinary Items After Taxes (Line 59 less Line 60)**		
62		**NET INCOME OR LOSS/COST OF SERVICE (Total of Lines 55-61)**		

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FOOTNOTE DATA

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FERC Account 246.2-Life Insurance

The 2020 balance in FERC 426.2 includes the net premium, less increase in cash surrender value of policies.

Cash surrender value of policies	$	(260,382)
Premiums		103,770
Total	$	(156,612)

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Schedule XVI- Analysis of Charges for Service- Associate and Non-Associate Companies

1. Total cost of service will equal for associate and nonassociate companies the total amount billed under their separate analysis of billing schedules.

Line No.	Account Number (a)	Title of Account (b)	Associate Company Direct Cost (c)	Associate Company Indirect Cost (d)	Associate Company Total Cost (e)	Nonassociate Company Direct Cost (f)	Nonassociate Company Indirect Cost (g)	Nonassociate Company Total Cost (h)
1	403-403.1	Depreciation Expense						
2	404-405	Amortization Expense						
3	407.3-407.4	Regulatory Debits/Credits – Net						
4	408.1-408.2	Taxes Other Than Income Taxes	8,644,013	14,857,178	23,501,191			
5	409.1-409.3	Income Taxes	16,078,424		16,078,424			
6	410.1-411.2	Provision for Deferred Taxes	(4,586,896)		(4,586,896)			
7	411.1-411.2	Provision for Deferred Taxes – Credit						
8	411.6	Gain from Disposition of Service Company Plant						
9	411.7	Losses from Disposition of Service Company Plant						
10	411.4-411.5	Investment Tax Credit Adjustment						
11	411.10	Accretion Expense						
12	412	Costs and Expenses of Construction or Other Services	516,508,842		516,508,842			
13	416	Costs and Expenses of Merchandising, Jobbing, and Contract Work for Associated Companies						
14	418	Non-operating Rental Income						
15	418.1	Equity in Earnings of Subsidiary Companies						
16	419	Interest and Dividend Income	623,955	3,248,735	3,872,690			
17	419.1	Allowance for Other Funds Used During Construction						
18	421	Miscellaneous Income or Loss						
19	421.1	Gain on Disposition of Property						
20	421.2	Loss on Disposition Of Property						
21	425	Miscellaneous Amortization						
22	426.1	Donations	272,709	321,964	594,673			
23	426.2	Life Insurance		(156,612)	(156,612)			
24	426.3	Penalties		12,047	12,047			
25	426.4	Expenditures for Certain Civic, Political and Related Activities	164,509	1,964,679	2,129,188			
26	426.5	Other Deductions	77,635	403,416	481,051			
27	427	Interest On Long-Term Debt						
28	428	Amortization of Debt Discount and Expense						
29	429	Amortization of Premium on Debt – Credit						
30	430	Interest on Debt to Associate Companies	2,563,524		2,563,524			
31	431	Other Interest Expense		408,032	408,032			
32	432	Allowance for Borrowed Funds Used During Construction						
33	500-509	Total Steam Power Generation Operation Expenses	29,724,224	7,668,403	37,392,627			
34	510-515	Total Steam Power Generation Maintenance Expenses	4,889,205	396,814	5,286,019			

Name of Respondent Xcel Energy Services Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Resubmission Date (Mo, Da, Yr) / /	Year/Period of Report Dec 31, 2020

Line No.	Account Number (a)	Title of Account (b)	Associate Company Direct Cost (c)	Associate Company Indirect Cost (d)	Associate Company Total Cost (e)	Nonassociate Company Direct Cost (f)	Nonassociate Company Indirect Cost (g)	Nonassociate Company Total Cost (h)
35	517-525	Total Nuclear Power Generation Operation Expenses	17,275,597		17,275,597			
36	528-532	Total Nuclear Power Generation Maintenance Expenses	250,467		250,467			
37	535-540.1	Total Hydraulic Power Generation Operation Expenses	1,924,332	379,322	2,303,654			
38	541-545.1	Total Hydraulic Power Generation Maintenance Expenses	437,482	14,569	452,051			
39	546-550.1	Total Other Power Generation Operation Expenses	8,245,660	3,973,514	12,219,174			
40	551-554.1	Total Other Power Generation Maintenance Expenses	5,099,899	267,735	5,367,634			
41	555-557	Total Other Power Supply Operation Expenses	10,370,865	8,738,588	19,109,453			
42	560	Operation Supervision and Engineering	11,774,348	11,647,127	23,421,475			
43	561.1	Load Dispatch-Reliability	15		15			
44	561.2	Load Dispatch-Monitor and Operate Transmission System	1,988,465	4,945,313	6,933,778			
45	561.3	Load Dispatch-Transmission Service and Scheduling						
46	561.4	Scheduling, System Control and Dispatch Services						
47	561.5	Reliability Planning and Standards Development	151,623	50,491	202,114			
48	561.6	Transmission Service Studies	(2,880)		(2,880)			
49	561.7	Generation Interconnection Studies	792,000		792,000			
50	561.8	Reliability Planning and Standards Development Services	6,857		6,857			
51	562	Station Expenses (Major Only)	8,521		8,521			
52	563	Overhead Line Expenses (Major Only)	217,547		217,547			
53	564	Underground Line Expenses (Major Only)	78		78			
54	565	Transmission of Electricity by Others (Major Only)	87		87			
55	566	Miscellaneous Transmission Expenses (Major Only)	10,697,727	(7,919)	10,689,808			
56	567	Rents	4,906,661	56,243	4,962,904			
57	567.1	Operation Supplies and Expenses (Nonmajor Only)						
58		Total Transmission Operation Expenses	30,541,049	16,691,255	47,232,304			
59	568	Maintenance Supervision and Engineering (Major Only)						
60	569	Maintenance of Structures (Major Only)						
61	569.1	Maintenance of Computer Hardware						
62	569.2	Maintenance of Computer Software						
63	569.3	Maintenance of Communication Equipment						
64	569.4	Maintenance of Miscellaneous Regional Transmission Plant						
65	570	Maintenance of Station Equipment (Major Only)	24,169		24,169			
66	571	Maintenance of Overhead Lines (Major Only)	118,576		118,576			
67	572	Maintenance of Underground Lines (Major Only)	378		378			
68	573	Maintenance of Miscellaneous Transmission Plant (Major Only)	71		71			

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Line No.	Account Number (a)	Title of Account (b)	Associate Company Direct Cost (c)	Associate Company Indirect Cost (d)	Associate Company Total Cost (e)	Nonassociate Company Direct Cost (f)	Nonassociate Company Indirect Cost (g)	Nonassociate Company Total Cost (h)
69	574	Maintenance of Transmission Plant (Nonmajor Only)						
70		Total Transmission Maintenance Expenses	143,194		143,194			
71	575.1-575.8	Total Regional Market Operation Expenses	1,087,960		1,087,960			
72	576.1-576.5	Total Regional Market Maintenance Expenses						
73	580-589	Total Distribution Operation Expenses	42,771,034	8,802,673	51,573,707			
74	590-598	Total Distribution Maintenance Expenses	2,649,314		2,649,314			
75		Total Electric Operation and Maintenance Expenses	694,509,087	61,494,842	756,003,929			
76	700-798	Production Expenses (Provide selected accounts in a footnote)	222,238		222,238			
77	800-813	Total Other Gas Supply Operation Expenses	968,446		968,446			
78	814-826	Total Underground Storage Operation Expenses	63,846		63,846			
79	830-837	Total Underground Storage Maintenance Expenses	32,235		32,235			
80	840-842.3	Total Other Storage Operation Expenses	491,029		491,029			
81	843.1-843.9	Total Other Storage Maintenance Expenses	1,165		1,165			
82	844.1-846.2	Total Liquefied Natural Gas Terminaling and Processing Operation Expenses	112,372		112,372			
83	847.1-847.8	Total Liquefied Natural Gas Terminaling and Processing Maintenance Expenses	4,226		4,226			
84	850	Operation Supervision and Engineering	1,751,779	975,278	2,727,057			
85	851	System Control and Load Dispatching.	155,489	784,178	939,667			
86	852	Communication System Expenses	8		8			
87	853	Compressor Station Labor and Expenses	3,619		3,619			
88	854	Gas for Compressor Station Fuel						
89	855	Other Fuel and Power for Compressor Stations						
90	856	Mains Expenses	72,864		72,864			
91	857	Measuring and Regulating Station Expenses	470		470			
92	858	Transmission and Compression of Gas By Others						
93	859	Other Expenses	734,216	969	735,185			
94	860	Rents	1,224,941	22	1,224,963			
95		Total Gas Transmission Operation Expenses	3,943,386	1,760,447	5,703,833			
96	861	Maintenance Supervision and Engineering						
97	862	Maintenance of Structures and Improvements						
98	863	Maintenance of Mains	10,775		10,775			
99	864	Maintenance of Compressor Station Equipment	11,672		11,672			
100	865	Maintenance of Measuring And Regulating Station Equipment	1,768		1,768			
101	866	Maintenance of Communication Equipment	27	22,782	22,809			
102	867	Maintenance of Other Equipment						
103		Total Gas Transmission Maintenance Expenses	24,242	22,782	47,024			
104	870-881	Total Distribution Operation Expenses	16,243,133	12,043,759	28,286,892			

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Line No.	Account Number (a)	Title of Account (b)	Associate Company Direct Cost (c)	Associate Company Indirect Cost (d)	Associate Company Total Cost (e)	Nonassociate Company Direct Cost (f)	Nonassociate Company Indirect Cost (g)	Nonassociate Company Total Cost (h)
105	885-894	Total Distribution Maintenance Expenses	656,917		656,917			
106		Total Natural Gas Operation and Maintenance Expenses	22,763,235	13,826,988	36,590,223			
107	901	Supervision		427,500	427,500			
108	902	Meter reading expenses	14,753,830	10,085,446	24,839,276			
109	903	Customer records and collection expenses	381,773	53,074,149	53,455,922			
110	904	Uncollectible accounts						
111	905	Miscellaneous customer accounts expenses	644,638		644,638			
112	906	Total Customer Accounts Operation Expenses	15,780,241	63,587,095	79,367,336			
113	907	Supervision						
114	908	Customer assistance expenses	495,296	514,023	1,009,319			
115	909	Informational And Instructional Advertising Expenses	324,334	1,096,943	1,421,277			
116	910	Miscellaneous Customer Service And Informational Expenses	249,864		249,864			
117		Total Service and Informational Operation Accounts	1,069,494	1,610,966	2,680,460			
118	911	Supervision						
119	912	Demonstrating and Selling Expenses	2,298,364	262,884	2,561,248			
120	913	Advertising Expenses						
121	916	Miscellaneous Sales Expenses	75,553		75,553			
122		Total Sales Operation Expenses	2,373,917	262,884	2,636,801			
123	920	Administrative and General Salaries	31,887,913	207,655,305	239,543,218			
124	921	Office Supplies and Expenses	28,844,364	81,368,798	110,213,162			
125	923	Outside Services Employed	4,892,314	37,988,475	42,880,789			
126	924	Property Insurance	97,158	78,073	175,231			
127	925	Injuries and Damages	(67,922)	16,772,787	16,704,865			
128	926	Employee Pensions and Benefits	22,934,985	39,716,025	62,651,010			
129	928	Regulatory Commission Expenses	108,932		108,932			
130	930.1	General Advertising Expenses	784,515	7,804,376	8,588,891			
131	930.2	Miscellaneous General Expenses	97,452	8,920,041	9,017,493			
132	931	Rents	12,257,143	103,093,275	115,350,418			
133		Total Administrative and General Operation Expenses	101,836,854	503,397,155	605,234,009			
134	935	Maintenance of Structures and Equipment	66,988	459,439	526,427			
135		Total Administrative and General Maintenance Expenses	121,127,494	569,317,539	690,445,033			
136		Total Cost of Service	838,399,816	644,639,369	1,483,039,185			

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Schedule XVI- Analysis of Charges for Service- Associate and Non-Associate Companies (continued)

Line No.	Account Number (a)	Title of Account (b)	Total Charges for Services Direct Cost (i)	Total Charges for Services Indirect Cost (j)	Total Charges for Services Total Cost (k)
1	403-403.1	Depreciation Expense			
2	404-405	Amortization Expense			
3	407.3-407.4	Regulatory Debits/Credits – Net			
4	408.1-408.2	Taxes Other Than Income Taxes	8,644,013	14,857,178	23,501,191
5	409.1-409.3	Income Taxes	16,078,424		16,078,424
6	410.1-411.2	Provision for Deferred Taxes	(4,586,896)		(4,586,896)
7	411.1-411.2	Provision for Deferred Taxes – Credit			
8	411.6	Gain from Disposition of Service Company Plant			
9	411.7	Losses from Disposition of Service Company Plant			
10	411.4-411.5	Investment Tax Credit Adjustment			
11	411.10	Accretion Expense			
12	412	Costs and Expenses of Construction or Other Services	516,508,842		516,508,842
13	416	Costs and Expenses of Merchandising, Jobbing, and Contract Work for Associated Companies			
14	418	Non-operating Rental Income			
15	418.1	Equity in Earnings of Subsidiary Companies			
16	419	Interest and Dividend Income	623,955	3,248,735	3,872,690
17	419.1	Allowance for Other Funds Used During Construction			
18	421	Miscellaneous Income or Loss			
19	421.1	Gain on Disposition of Property			
20	421.2	Loss on Disposition Of Property			
21	425	Miscellaneous Amortization			
22	426.1	Donations	272,709	321,964	594,673
23	426.2	Life Insurance		(156,612)	(156,612)
24	426.3	Penalties		12,047	12,047
25	426.4	Expenditures for Certain Civic, Political and Related Activities	164,509	1,964,679	2,129,188
26	426.5	Other Deductions	77,635	403,416	481,051
27	427	Interest On Long-Term Debt			
28	428	Amortization of Debt Discount and Expense			
29	429	Amortization of Premium on Debt – Credit			
30	430	Interest on Debt to Associate Companies	2,563,524		2,563,524
31	431	Other Interest Expense		408,032	408,032
32	432	Allowance for Borrowed Funds Used During Construction			
33	500-509	Total Steam Power Generation Operation Expenses	29,724,224	7,668,403	37,392,627
34	510-515	Total Steam Power Generation Maintenance Expenses	4,889,205	396,814	5,286,019

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Schedule XVI- Analysis of Charges for Service- Associate and Non-Associate Companies (continued)

Line No.	Account Number (a)	Title of Account (b)	Total Charges for Services Direct Cost (i)	Total Charges for Services Indirect Cost (j)	Total Charges for Services Total Cost (k)
35	517-525	Total Nuclear Power Generation Operation Expenses	17,275,597		17,275,597
36	528-532	Total Nuclear Power Generation Maintenance Expenses	250,467		250,467
37	535-540.1	Total Hydraulic Power Generation Operation Expenses	1,924,332	379,322	2,303,654
38	541-545.1	Total Hydraulic Power Generation Maintenance Expenses	437,482	14,569	452,051
39	546-550.1	Total Other Power Generation Operation Expenses	8,245,660	3,973,514	12,219,174
40	551-554.1	Total Other Power Generation Maintenance Expenses	5,099,899	267,735	5,367,634
41	555-557	Total Other Power Supply Operation Expenses	10,370,865	8,738,588	19,109,453
42	560	Operation Supervision and Engineering	11,774,348	11,647,127	23,421,475
43	561.1	Load Dispatch-Reliability	15		15
44	561.2	Load Dispatch-Monitor and Operate Transmission System	1,988,465	4,945,313	6,933,778
45	561.3	Load Dispatch-Transmission Service and Scheduling			
46	561.4	Scheduling, System Control and Dispatch Services			
47	561.5	Reliability Planning and Standards Development	151,623	50,491	202,114
48	561.6	Transmission Service Studies	(2,880)		(2,880)
49	561.7	Generation Interconnection Studies	792,000		792,000
50	561.8	Reliability Planning and Standards Development Services	6,857		6,857
51	562	Station Expenses (Major Only)	8,521		8,521
52	563	Overhead Line Expenses (Major Only)	217,547		217,547
53	564	Underground Line Expenses (Major Only)	78		78
54	565	Transmission of Electricity by Others (Major Only)	87		87
55	566	Miscellaneous Transmission Expenses (Major Only)	10,697,727	(7,919)	10,689,808
56	567	Rents	4,906,661	56,243	4,962,904
57	567.1	Operation Supplies and Expenses (Nonmajor Only)			
58		Total Transmission Operation Expenses	30,541,049	16,691,255	47,232,304
59	568	Maintenance Supervision and Engineering (Major Only)			
60	569	Maintenance of Structures (Major Only)			
61	569.1	Maintenance of Computer Hardware			
62	569.2	Maintenance of Computer Software			
63	569.3	Maintenance of Communication Equipment			
64	569.4	Maintenance of Miscellaneous Regional Transmission Plant			
65	570	Maintenance of Station Equipment (Major Only)	24,169		24,169
66	571	Maintenance of Overhead Lines (Major Only)	118,576		118,576
67	572	Maintenance of Underground Lines (Major Only)	378		378
68	573	Maintenance of Miscellaneous Transmission Plant (Major Only)	71		71

Name of Respondent Xcel Energy Services Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Resubmission Date (Mo, Da, Yr) / /	Year/Period of Report Dec 31, 2020

Schedule XVI- Analysis of Charges for Service- Associate and Non-Associate Companies (continued)

Line No.	Account Number (a)	Title of Account (b)	Total Charges for Services Direct Cost (i)	Total Charges for Services Indirect Cost (j)	Total Charges for Services Total Cost (k)
69	574	Maintenance of Transmission Plant (Nonmajor Only)			
70		Total Transmission Maintenance Expenses	143,194		143,194
71	575.1-575.8	Total Regional Market Operation Expenses	1,087,960		1,087,960
72	576.1-576.5	Total Regional Market Maintenance Expenses			
73	580-589	Total Distribution Operation Expenses	42,771,034	8,802,673	51,573,707
74	590-598	Total Distribution Maintenance Expenses	2,649,314		2,649,314
75		Total Electric Operation and Maintenance Expenses	694,509,087	61,494,842	756,003,929
76	700-798	Production Expenses (Provide selected accounts in a footnote)	222,238		222,238
77	800-813	Total Other Gas Supply Operation Expenses	968,446		968,446
78	814-826	Total Underground Storage Operation Expenses	63,846		63,846
79	830-837	Total Underground Storage Maintenance Expenses	32,235		32,235
80	840-842.3	Total Other Storage Operation Expenses	491,029		491,029
81	843.1-843.9	Total Other Storage Maintenance Expenses	1,165		1,165
82	844.1-846.2	Total Liquefied Natural Gas Terminaling and Processing Operation Expenses	112,372		112,372
83	847.1-847.8	Total Liquefied Natural Gas Terminaling and Processing Maintenance Expenses	4,226		4,226
84	850	Operation Supervision and Engineering	1,751,779	975,278	2,727,057
85	851	System Control and Load Dispatching.	155,489	784,178	939,667
86	852	Communication System Expenses	8		8
87	853	Compressor Station Labor and Expenses	3,619		3,619
88	854	Gas for Compressor Station Fuel			
89	855	Other Fuel and Power for Compressor Stations			
90	856	Mains Expenses	72,864		72,864
91	857	Measuring and Regulating Station Expenses	470		470
92	858	Transmission and Compression of Gas By Others			
93	859	Other Expenses	734,216	969	735,185
94	860	Rents	1,224,941	22	1,224,963
95		Total Gas Transmission Operation Expenses	3,943,386	1,760,447	5,703,833
96	861	Maintenance Supervision and Engineering			
97	862	Maintenance of Structures and Improvements			
98	863	Maintenance of Mains	10,775		10,775
99	864	Maintenance of Compressor Station Equipment	11,672		11,672
100	865	Maintenance of Measuring And Regulating Station Equipment	1,768		1,768
101	866	Maintenance of Communication Equipment	27	22,782	22,809
102	867	Maintenance of Other Equipment			
103		Total Gas Transmission Maintenance Expenses	24,242	22,782	47,024
104	870-881	Total Distribution Operation Expenses	16,243,133	12,043,759	28,286,892

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Schedule XVI- Analysis of Charges for Service- Associate and Non-Associate Companies (continued)

Line No.	Account Number (a)	Title of Account (b)	Total Charges for Services Direct Cost (i)	Total Charges for Services Indirect Cost (j)	Total Charges for Services Total Cost (k)
105	885-894	Total Distribution Maintenance Expenses	656,917		656,917
106		Total Natural Gas Operation and Maintenance Expenses	22,763,235	13,826,988	36,590,223
107	901	Supervision		427,500	427,500
108	902	Meter reading expenses	14,753,830	10,085,446	24,839,276
109	903	Customer records and collection expenses	381,773	53,074,149	53,455,922
110	904	Uncollectible accounts			
111	905	Miscellaneous customer accounts expenses	644,638		644,638
112	906	Total Customer Accounts Operation Expenses	15,780,241	63,587,095	79,367,336
113	907	Supervision			
114	908	Customer assistance expenses	495,296	514,023	1,009,319
115	909	Informational And Instructional Advertising Expenses	324,334	1,096,943	1,421,277
116	910	Miscellaneous Customer Service And Informational Expenses	249,864		249,864
117		Total Service and Informational Operation Accounts	1,069,494	1,610,966	2,680,460
118	911	Supervision			
119	912	Demonstrating and Selling Expenses	2,298,364	262,884	2,561,248
120	913	Advertising Expenses			
121	916	Miscellaneous Sales Expenses	75,553		75,553
122		Total Sales Operation Expenses	2,373,917	262,884	2,636,801
123	920	Administrative and General Salaries	31,887,913	207,655,305	239,543,218
124	921	Office Supplies and Expenses	28,844,364	81,368,798	110,213,162
125	923	Outside Services Employed	4,892,314	37,988,475	42,880,789
126	924	Property Insurance	97,158	78,073	175,231
127	925	Injuries and Damages	(67,922)	16,772,787	16,704,865
128	926	Employee Pensions and Benefits	22,934,985	39,716,025	62,651,010
129	928	Regulatory Commission Expenses	108,932		108,932
130	930.1	General Advertising Expenses	784,515	7,804,376	8,588,891
131	930.2	Miscellaneous General Expenses	97,452	8,920,041	9,017,493
132	931	Rents	12,257,143	103,093,275	115,350,418
133		Total Administrative and General Operation Expenses	101,836,854	503,397,155	605,234,009
134	935	Maintenance of Structures and Equipment	66,988	459,439	526,427
135		Total Administrative and General Maintenance Expenses	121,127,494	569,317,539	690,445,033
136		Total Cost of Service	838,399,816	644,639,369	1,483,039,185

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Schedule XVII - Analysis of Billing – Associate Companies (Account 457)

1. For services rendered to associate companies (Account 457), list all of the associate companies.

Line No.	Name of Associate Company (a)	Account 457.1 Direct Costs Charged (b)	Account 457.2 Indirect Costs Charged (c)	Account 457.3 Compensation For Use of Capital (d)	Total Amount Billed (e)
1	NSP-Minnesota	316,602,336	266,245,206	677,345	583,524,887
2	PSCo	339,377,776	230,705,544	1,073,140	571,156,460
3	SPS	117,160,533	82,018,015	470,408	199,648,956
4	NSP-Wisconsin	50,345,914	41,408,289	122,554	91,876,757
5	Xcel Energy, Inc.	5,379,649	22,489,151	(419,665)	27,449,135
6	Xcel Energy Joint Ventures	5,412,717			5,412,717
7	MEC Holdings, LLC	827,506	1,096,051	6,968	1,930,525
8	Nicollet Project Holdings	274,184		1,322	275,506
9	Nicollet Holdings Company	258,275		533	258,808
10	Eloigne Company	70,086	160,545	394	231,025
11	Capital Services, LLC	27,937	188,643	354	216,934
12	Nicollet Projects I, LLC	139,065	73,666	588	213,319
13	Xcel Energy WYCO, Inc.	23,134	163,301	3,759	190,194
14	Xcel Energy Transmission Development Company, LLC	184,694	93	1,114	185,901
15	Nicollet Land Services, LLC	136,840		109	136,949
16	Quixx Corporation	55,045			55,045
17	Chippewa and Flambeau Improvement Company	39,259	4,213	67	43,539
18	Energy Impact Fund Investments, Inc.	6,784	33,836	56	40,676
19	1480 Welton, Inc.	7,610	31,534	55	39,199
20	P.S.R. Investments, Inc	7,720	8,928	299	16,947
21	e-prime, Inc.	12,705			12,705
22	WestGas Interstate, Inc.	10,808	1,690	23	12,521
23	Xcel Energy West Transmission Company, LLC	12,392		19	12,411
24	Xcel Energy Performance Contracting, Inc.	11,244	394	28	11,666
25	Xcel Energy Wholesale Group, Inc.	11,497			11,497
26	Clearwater Investments, Inc.	4,842	5,310	18	10,170
27	United Power & Land Company	6,665	1,069	6	7,740
28	Xcel Energy Retail Holdings Inc.	6,894		8	6,902
29	Xcel Energy Ventures, Inc.	6,879		10	6,889
30	Xcel Energy Markets Holdings, Inc.	6,095		6	6,101
31	Xcel Energy Ventures Holdings, Inc.	6,013		10	6,023
32	Xcel Energy Transmission Holding Company, LLC	5,239	429	9	5,677
33	Xcel Energy International, Inc.	5,036			5,036
34	Xcel Energy Communications Group, Inc.	4,963		6	4,969
35	Xcel Energy Southwest Transmission Company, LLC	3,953	238	6	4,197
36	Reddy Kilowatt Corporation	1,102	2,781	15	3,898
37	Seren Innovations, Inc.	3,646			3,646
38	Xcel Energy Investments	1,666	443	3	2,112
39	NSP Lands, Inc.	1,544		2	1,546
40	**Total**	**836,460,247**	**644,639,369**	**1,939,569**	**1,483,039,185**

Name of Respondent	This Report is:	Resubmission Date (Mo, Da, Yr)	Year of Report
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FOOTNOTE DATA

Schedule Page: 307   Line No.: 6   Column: e

Xcel Energy Joint Ventures:

The amount represents the combined total of all Xcel Energy Joint Ventures as listed below:

Joint Venture CAPX	$	2,202,681
Joint Venture Sherco 3		1,592,895
Joint Vent Comanche 3		1,374,813
Joint Venture Hayden		242,328
Joint Venture Tri-State		-
Total	$	5,412,717

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Schedule XVIII – Analysis of Billing – Non-Associate Companies (Account 458)

1. For services rendered to nonassociate companies (Account 458), list all of the nonassociate companies. In a footnote, describe the services rendered to each respective nonassociate company.

Line No.	Name of Non-associate Company (a)	Account 458.1 Direct Costs Charged (b)	Account 458.2 Indirect Costs Charged (c)	Account 458.3 Compensation For Use of Capital (d)	Account 458.4 Excess or Deficiency on Servicing Non-associate Utility Companies (e)	Total Amount Billed (f)
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40	**Total**					

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
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Schedule XIX - Miscellaneous General Expenses - Account 930.2

1. Provide a listing of the amount included in Account 930.2, "Miscellaneous General Expenses" classifying such expenses according to their nature. Amounts less than $50,000 may be grouped showing the number of items and the total for the group.
2. Payments and expenses permitted by Section 321 (b)(2) of the Federal Election Campaign Act, as amended by Public Law 94-283 in 1976 (2 U.S.C. 441(b)(2)) shall be separately classified.

Line No.	Title of Account (a)	Amount (b)
1	Utility Association Dues	4,149,525
2	Board of Directors Fees and Expenses	4,143,403
3	Shareholder Relation Expenses	372,873
4	SEC Filing and Shareholder Reporting Expenses	351,692
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40	**Total**	**9,017,493**

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Schedule XX - Organization Chart

1. Provide a graphical presentation of the relationships and inter relationships within the service company that identifies lines of authority and responsibility in the organization.

Schedule XX – Organization Chart

Organization Chart	Service Function *
Chief Executive Officer (CEO)	Executive Management Services
Corporate Other	Accounting, Financial Reporting & Taxes
Corporate Secretary & Executive Services	Executive Management Services
Communications	Executive Management Services
Corporate Communications	Corporate Communications, Employee Communications
Strategic Communications	Corporate Communications, Employee Communications, Marketing & Sales
Corporate Compliance	Executive Management Services
Shareholder Relations	Corporate Communications, Investor Relations
Strategy & Planning	Corporate Strategy & Business Development
Utilities & Corporate Services	Executive Management Services
Employee & Business Services	Executive Management Services
Aviation & Travel Services	Aviation Services
Enterprise Security	Executive Management Services & Facilities & Real Estate
Property Services	Facilities Admin. Services & Facilities & Real Estate
Workforce Relations & Safety	Energy Supply Business Resources & Human Resources
Business Systems	Business Systems
Chief Administrative Office (CAO)	Executive Management Services, Government Affairs
Corporate Giving	Corporate Communications
Resource Planning	Energy Markets Regulated Trading & Marketing
Human Resources	Human Resources
Payroll	Payroll
Marketing	Marketing & Sales
Group President	Executive Management Services
NSPM President	Government Affairs & Rates & Regulation
NSPW President	Government Affairs & Rates & Regulation
PSCo President	Government Affairs & Rates & Regulation
SPS President	Government Affairs & Rates & Regulation
Financial Operations	Accounting, Financial Reporting & Taxes
Chief Financial Officer	Accounting, Financial Reporting & Taxes
Controller	Accounting, Financial Reporting & Taxes
Corporate Development	Corporate Strategy & Business Development
Financial Planning	Accounting, Financial Reporting & Taxes, Finance & Treasury, Rates & Regulation
Investor Relations	Investor Relations
Revenue Requirements	Rates & Regulation
Risk Management & Audit Services	Finance & Treasury, Internal Audit & Risk
Tax Services	Accounting, Financial Reporting & Taxes
Treasurer	Finance & Treasury

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Schedule XX - Organization Chart

Schedule XX – Organization Chart

Corporate Policy & Federal Affairs	Government Affairs, Rates & Regulation
General Counsel	Legal
Claims	Claims Services
Legal Services	Legal
Operations Services	Executive Management
Commercial Operations	Energy Markets Regulated Trading & Marketing & Energy Markets – Fuel Procurement
Customer Care	Customer Service; Receipts Processing
Enterprise Transformation Office (ETO)	Business Systems
Chief Innovation and Information Officer	Business Systems
Distribution Operations	Energy Delivery Marketing; Energy Delivery (COM); Energy Delivery Engineering/Design
Gas Systems	Energy Delivery Marketing; Energy Delivery (COM); Energy Delivery Engineering/Design
Energy Supply	Energy Supply Business Resources
Engineering & Construction	Energy Supply Engineering & Environmental; Energy Supply Business Resources
Environmental	Energy Supply Engineering & Environmental
Operations (Regional Generation)	Energy Supply Business Resources
Technical Services	Energy Supply Business Resources
Supply Chain	Supply Chain; Supply Chain Special Programs; Payment & Reporting & Fleet
Transmission	Energy Delivery Marketing; Energy Delivery (COM); Energy Delivery Engineering/Design

* The "Service Function" column sets forth the primary service functions for each area; however, others may be used based on a case-by-case basis depending on the specific work being performed.

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Schedule XXI - Methods of Allocation

1. Indicate the service department or function and the basis for allocation used when employees render services to more than one department or functional group. If a ratio, include the numerator and denominator.
2. Include any other allocation methods used to allocate costs.

Service Department or Function	Basis of Allocation*
Executive Management Services	Executive Management Services indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio.
Investor Relations	Investor Relations indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio.
Internal Audit & Risk	Internal Audit and Risk indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio, except for: (1) indirect costs associated with proprietary trading activities, which will be allocated based on the Joint Operating Agreement Peak Hour Megawatt Load Ratio, provided, however, that indirect costs provided jointly for both generation trading activities and proprietary trading activities will be allocated based on the Joint Operating Agreement Labor Hours Ratio.
Legal	Legal indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio.
Claims Services	Claims Services indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio.
Corporate Communications	Corporate Communications indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio.
Employee Communications	Employee Communications indirect costs will be allocated based on the Employee Ratio.
Corporate Strategy & Business Development	Corporate Strategy & Business Development indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio.
Government Affairs	Government Affairs indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio.

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Schedule XXI - Methods of Allocation

Facilities & Real Estate	Facilities & Real Estate indirect costs will be allocated based on the Employee Ratio.	
Facilities Administrative Services	Facilities Administrative Services indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio.	
Supply Chain	Supply Chain will be direct charged. Any management and oversight of the payment and reporting services activities that cannot be direct charged will be allocated based on the Invoice Transaction Ratio.	
Supply Chain Special Programs	Supply Chain Special Programs indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio.	
Human Resources	Human Resources indirect costs will be allocated based on the Employee Ratio.	
Finance & Treasury	Finance & Treasury indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio, except for: (1) indirect costs associated with proprietary trading activities, which will be allocated based on the Joint Operating Agreement Peak Hour Megawatt Load Ratio, provided, however, that indirect costs provided jointly for both generation trading activities and proprietary trading activities will be allocated based on the Joint Operating Agreement Labor Hours Ratio.	
Accounting, Financial Reporting & Taxes	Accounting, Financial Reporting & Taxes indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio, except for: (1) indirect costs associated with proprietary trading activities, which will be allocated based on the Joint Operating Agreement Peak Hour Megawatt Load Ratio, provided, however, that indirect costs provided jointly for both generation trading activities and proprietary trading activities will be allocated based on the Joint Operating Agreement Labor Hours Ratio.	
Payment & Reporting	Payment & Reporting indirect costs will be allocated based on the Invoice Transaction Ratio.	
Receipts Processing	Receipts Processing indirect costs will be allocated based on the Customer Bills Ratio.	

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Schedule XXI - Methods of Allocation

Payroll	Payroll indirect costs will be allocated based on the Employee Ratio.
Rates & Regulation	Rates & Regulation indirect costs will be allocated based on the Direct Labor Ratio.
Energy Supply Engineering and Environmental	Energy Supply Engineering and Environmental services will be direct charged; administrative support functions that cannot be direct charged will be allocated based on the Total Plant Ratio.
Energy Supply Business Resources	Energy Supply Business Resources indirect costs will be allocated based on the MWh Generation Ratio.
Energy Markets Regulated Trading & Marketing	Energy Markets Regulated Trading & Marketing indirect costs will be allocated based on the Total MWh Sales Ratio, except for: (1) indirect costs associated with proprietary trading activities, which will be allocated based on the Joint Operating Agreement Peak Hour Megawatt Load Ratio, provided, however, that indirect costs provided jointly for both generation trading activities and proprietary trading activities will be allocated based on the Joint Operating Agreement Labor Hours Ratio.
Energy Markets - Fuel Procurement	Energy Markets Fuel Procurement indirect costs will be allocated based on the MWh Generation Ratio.
Energy Delivery Marketing	Energy Delivery Marketing will be direct charged.
Energy Delivery Construction, Operations & Maintenance (COM)	Energy Delivery COM indirect costs will be allocated based on the Delivery Services Gross Plant Ratio.
Energy Delivery Engineering/Design	Energy Delivery Engineering/Design services will be direct charged; administrative support functions that cannot be direct charged will be allocated based on the Delivery Services Gross Plant Ratio.
Marketing & Sales	Marketing & Sales indirect costs will be allocated based on the Revenue Ratio.
Customer Service	Customer Service indirect costs will be allocated based on the Customers Ratio. Indirect costs associated with administering low income and certified medical customer assistance programs will be allocated based on a composite of the average of the Special Needs Customer Contacts Ratio and Residential Customers Ratio.
Business Systems	Business Systems indirect costs will be allocated using any

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Schedule XXI - Methods of Allocation

	of the allocation ratios or combination of ratios.
Aviation Services	Aviation Services will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio, and the Total Assets Ratio.
Fleet	Fleet will be direct charged.

* Corporate Governance activities within this Service Function will be allocated using the average of the Revenue Ratio with intercompany dividends assigned to Xcel Energy Inc., Employee Ratio with number of common officers assigned to Xcel Energy Inc., and the Total Assets Ratio including Xcel Energy Inc.'s per book assets.

Allocation Ratios

The following ratios will be utilized as outlined above.

Revenue Ratio - Based on the sum of the monthly revenue amounts for the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Revenue Ratio with intercompany dividends assigned to Xcel Energy Inc. - Based on the sum of the monthly revenue amounts for the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. Xcel Energy Inc. will be assigned the amount of intercompany dividends. This ratio will be determined annually, or at such time as may be required due to significant changes.

Employee Ratio - Based on the number of employees at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes

Employee Ratio with number of common officers assigned to Xcel Energy Inc. - Based on the number of employees at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. Xcel Energy Inc. will be assigned the number of common officers. This ratio will be determined annually, or at such time as may be required due to significant changes.

Total Assets Ratio - Based on the total assets as of December 31 for the prior year, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Total Assets Ratio including Xcel Energy Inc's Per Book Assets - Based on the total assets as of December 31 for the prior year, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. Xcel Energy Inc. will be assigned the per book assets of Xcel Energy Inc. This ratio will be determined annually, or at such time as may be required due to significant changes.

Square Footage Ratio - Based on the total square footage as of December 31 for the prior year, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Invoice Transaction Ratio - Based on the sum of the monthly number of invoice transactions processed for the prior year

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ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually or at such time as may be required due to significant changes.

Customer Bills Ratio - Based on the average of the monthly total number of customer bills issued during the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

MWh Generation Ratio - Based on the sum of the monthly electric MWh generated by type of generator during the prior year ending December 31, the numerator of which is for an applicable Operating Company and the denominator of which is for all applicable Operating Companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Total MWh Sales Ratio - Based on the sum of the monthly electric MWh hours sold during the prior year ending December 31, the numerator of which is for an applicable Operating Company and the denominator of which is for all applicable Operating Companies. This includes sales to ultimate customers, wholesale customers, and non-requirement sales for resale. This ratio will be determined annually, or at such time as may be required due to significant changes.

Customers Ratio - Based on the average of the monthly total electric customers (and/or gas customers, or residential, business and large commercial and industrial customers where applicable) for the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Delivery Services Gross Plant Ratio - Based on transmission and distribution gross plant for the Delivery Business unit, both electric and gas or as may be applicable Electric Distribution for the prior year ending December 31, the numerator of which is an applicable Operating Company and the denominator of which is for all applicable Operating Companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Provided, however, as follows:
(1) If the costs being allocated are directly related only to electric transmission, the ratio shall be based on the electric transmission gross plant;
(2) If the costs being allocated are directly related only to electric distribution, the ratio shall be based on the electric distribution gross plant;
(3) If the costs being allocated are directly related only to gas transmission, the ratio shall be based on the gas transmission gross plant;
(4) If the costs being allocated are directly related only to gas distribution, the ratio shall be based on the gas distribution gross plant;
(5) If the costs being allocated are directly related only to electric transmission and electric distribution, the ratio shall be based on the sum of the electric transmission gross plant and the electric distribution gross plant;
(6) If the costs being allocated are directly related only to electric transmission and gas transmission, the ratio shall be based on the sum of the electric transmission gross plant and the gas transmission gross plant;
(7) If the costs being allocated are directly related only to electric transmission and gas distribution, the ratio shall be based on the sum of the electric transmission gross plant and the gas distribution gross plant;

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(8) If the costs being allocated are directly related only to electric distribution and gas transmission, the ratio shall be based on the sum of the electric distribution gross plant and the gas transmission gross plant;
(9) If the costs being allocated are directly related only to electric distribution and gas distribution, the ratio shall be based on the sum of the electric distribution gross plant and the gas distribution gross plant;

(10) If the costs being allocated are directly related only to gas transmission and gas distribution, the ratio shall be based on the sum of the gas transmission gross plant and the gas distribution gross plant;
(11) If the costs being allocated are directly related only to electric transmission, electric distribution, and gas transmission, the ratio shall be based on the sum of the electric transmission gross plant, the electric distribution gross plant, and the gas transmission gross plant;
(12) If the costs being allocated are directly related only to electric transmission, electric distribution, and gas distribution, the ratio shall be based on the sum of the electric transmission gross plant, the electric distribution gross plant, and the gas distribution gross plant;
(13) If the costs being allocated are directly related only to electric transmission, gas transmission, and gas distribution, the ratio shall be based on the sum of the electric transmission gross plant, the gas transmission gross plant, and the gas distribution gross plant;
(14) If the costs being allocated are directly related only to electric distribution, gas transmission, and gas distribution, the ratio shall be based on the sum of the electric distribution plant, the gas transmission gross plant, and the gas distribution gross plant.

Meters Ratio - Based on the number of meters at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

Provided, however, as follows:
(1) If the costs being allocated are directly related only to Advanced Metering Infrastructure ("AMI") enabled meters, the ratio shall be based on the number of AMI enabled meters.

Customer Contacts Ratio - Based on the total annual number of customer contacts at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

If the costs being allocated are directly related only to the support of special needs customers, such as those receiving low income energy assistance program and those having certified medical conditions, the Special Needs Customer Contacts Ratio shall be used.

Special Needs Customer Contacts Ratio - Based on the number of contacts received by the special needs customer department at the end of the prior year ending December 31. The numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. The ratio will be determined annually, or at such a time as may be required due to significant changes.

Accounts Payable Transactions Ratio - Based on the total annual number of accounts payable transactions by system application at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

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Inventory Transactions Ratio - Based on the total annual number of inventory transactions by system application at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

Work Management Transactions Ratio - Based on the total annual number of work management transactions by system application at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

Purchasing Transactions Ratio - Based on the total annual number of purchasing transactions by system application at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

Total Plant Ratio - Based on total property, plant and equipment at the end of the prior year ending December 31, the numerator of which is an applicable Operating Company and the denominator of which is for all applicable Operating Companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

Provided, however, as follows:
(1) If the costs being allocated are directly related only to electric production, the ratio shall be based on the total electric production plant;
(2) If the costs being allocated are directly related only to electric transmission, the ratio shall be based on the total electric transmission plant;
(3) If the costs being allocated are directly related only to electric distribution, the ratio shall be based on the total electric distribution plant;
(4) If the costs being allocated are directly related only to gas transmission, the ratio shall be based on the total gas transmission plant;
(5) If the costs being allocated are directly related only to gas distribution, the ratio shall be based on the total gas distribution plant;
(6) If the costs being allocated are directly related only to intangible plant, the ratio shall be based on the total intangible plant;
(7) If the costs being allocated are directly related only to electric production and electric transmission, the ratio shall be based on the sum of the total electric production plant and the total electric transmission plant;
(8) If the costs being allocated are directly related only to electric production and electric distribution, the ratio shall be based on the sum of the total electric production plant and the total electric distribution plant;
(9) If the costs being allocated are directly related only to electric production and gas transmission, the ratio shall be based on the sum of the total electric production plant and the total gas transmission plant;
(10) If the costs being allocated are directly related only to electric production and gas distribution, the ratio shall be based on the sum of the total electric production plant and the total gas distribution plant;
(11) If the costs being allocated are directly related only to electric production and intangible plant, the ratio shall be based on the sum of the total electric production plant and the total intangible plant;
(12) If the costs being allocated are directly related only to electric transmission and electric distribution, the ratio shall be based on the sum of the total electric transmission plant and the total electric distribution plant;

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(13) If the costs being allocated are directly related only to electric transmission and gas transmission, the ratio shall be based on the sum of the total electric transmission plant and the total gas transmission plant;
(14) If the costs being allocated are directly related only to electric transmission and gas distribution, the ratio shall be based on the sum of the total electric transmission plant and the total gas distribution plant;
(15) If the costs being allocated are directly related only to electric transmission and intangible plant, the ratio shall be based on the sum of the total electric transmission plant and the total intangible plant;
(16) If the costs being allocated are directly related only to electric distribution and gas transmission, the ratio shall be based on the sum of the total electric distribution plant and the total gas transmission plant;
(17) If the costs being allocated are directly related only to electric distribution and gas distribution, the ratio shall be based on the sum of the total electric distribution plant and the total gas distribution plant;
(18) If the costs being allocated are directly related only to electric distribution and intangible plant, the ratio shall be based on the sum of the total electric distribution plant and the total intangible plant;
(19) If the costs being allocated are directly related only to gas transmission and gas distribution, the ratio shall be based on the sum of the total gas transmission plant and the total gas distribution plant;
(20) If the costs being allocated are directly related only to gas transmission and intangible plant, the ratio shall be based on the sum of the total gas transmission plant and the total intangible plant;
(21) If the costs being allocated are directly related only to gas distribution and intangible plant, the ratio shall be based on the sum of the total gas distribution plant and the total intangible plant;
(22) If the costs being allocated are directly related only to electric production, electric transmission, and electric distribution, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, and the total electric distribution plant;
(23) If the costs being allocated are directly related only to electric production, electric transmission, and gas transmission, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, and the total gas transmission plant;
(24) If the costs being allocated are directly related only to electric production, electric transmission, and gas distribution, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, and the total gas distribution plant;
(25) If the costs being allocated are directly related only to electric production, electric transmission, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, and the total intangible plant;
(26) If the costs being allocated are directly related only to electric production, electric distribution, and gas transmission, the ratio shall be based on the sum of the total electric production plant, the total electric distribution plant, and the total gas transmission plant;
(27) If the costs being allocated are directly related only to electric production, electric distribution, and gas distribution, the ratio shall be based on the sum of the total electric production plant, the total electric distribution plant, and the total gas distribution plant;
(28) If the costs being allocated are directly related only to electric production, electric distribution, and intangible, the ratio shall be based on the sum of the total electric production plant, the total electric distribution plant, and the total intangible plant;
(29) If the costs being allocated are directly related only to electric production, gas transmission, and gas distribution, the ratio shall be based on the sum of the total electric production plant, the total gas transmission plant, and the total gas distribution plant;
(30) If the costs being allocated are directly related only to electric production, gas transmission, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total gas transmission plant, and the total intangible plant;
(31) If the costs being allocated are directly related only to electric production, gas distribution, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total gas distribution plant, and the total intangible plant;
(32) If the costs being allocated are directly related only to electric transmission, electric distribution, and gas transmission, the ratio shall be based on the sum of the total electric transmission plant, the total electric distribution plant, and the total gas transmission plant;
(33) If the costs being allocated are directly related only to electric transmission, electric distribution, and gas distribution, the ratio shall be based on the sum of the total electric transmission plant, the total electric distribution plant, and the total gas distribution plant;

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(34) If the costs being allocated are directly related only to electric transmission, electric distribution, and intangible plant, the ratio shall be based on the sum of the total electric transmission plant, the total electric distribution plant, and the total intangible plant;
(35) If the costs being allocated are directly related only to electric transmission, gas transmission, and gas distribution, the ratio shall be based on the sum of the total electric transmission plant, the total gas transmission plant, and the total gas distribution plant;
(36) If the costs being allocated are directly related only to electric transmission, gas transmission, and intangible plant, the ratio shall be based on the sum of the total electric transmission plant, the total gas transmission plant, and the total intangible plant;
(37) If the costs being allocated are directly related only to electric transmission, gas distribution, and intangible plant, the ratio shall be based on the sum of the total electric transmission plant, the total gas distribution plant, and the total intangible plant;
(38) If the costs being allocated are directly related only to electric distribution, gas transmission, and intangible plant, the ratio shall be based on the sum of the total electric distribution plant, the total gas transmission plant, and the total intangible plant;
(39) If the costs being allocated are directly related only to electric distribution, gas distribution, and intangible plant, the ratio shall be based on the sum of the total electric distribution plant, the total gas distribution plant, and the total intangible plant;
(40) If the costs being allocated are directly related only to electric distribution, gas distribution, and gas transmission, the ratio shall be based on the sum of the total electric distribution plant, the total gas distribution plant, and the total gas transmission plant;
(41) If the costs being allocated are directly related only to gas transmission, gas distribution, and intangible plant, the ratio shall be based on the sum of the total gas transmission plant, the total gas distribution plant, and the total intangible plant;
(42) If the costs being allocated are directly related only to electric production, electric transmission, electric distribution, and gas transmission, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, the total electric distribution plant, and the total gas transmission plant;
(43) If the costs being allocated are directly related only to electric production, electric transmission, electric distribution, and gas distribution, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, the total electric distribution plant, and the total gas distribution plant;
(44) If the costs being allocated are directly related only to electric production, electric transmission, electric distribution, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, the total electric distribution plant, and the total intangible plant;
(45) If the costs being allocated are directly related only to electric production, electric transmission, gas transmission, and gas distribution, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, the total gas transmission plant, and the total gas distribution plant;
(46) If the costs being allocated are directly related only to electric production, electric transmission, gas transmission, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, the total gas transmission plant, and the total intangible plant;
(47) If the costs being allocated are directly related only to electric production, electric distribution, gas transmission, and gas distribution, the ratio shall be based on the sum of the total electric production plant, the total electric distribution plant, the total gas transmission plant, and the total gas distribution plant;

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(48) If the costs being allocated are directly related only to electric production, electric distribution, gas transmission, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total electric distribution plant, the total gas transmission plant, and the total intangible plant;
(49) If the costs being allocated are directly related only to electric production, electric distribution, gas distribution, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total electric distribution plant, the total gas distribution plant, and the total intangible plant;
(50) If the costs being allocated are directly related only to electric production, gas transmission, gas distribution, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total gas transmission plant, the total gas distribution plant, and the total intangible plant;
(51) If the costs being allocated are directly related only to electric transmission, electric distribution, gas transmission, and gas distribution, the ratio shall be based on the sum of the total electric transmission plant, the total electric distribution plant, the total gas transmission plant, and the total gas distribution plant;
(52) If the costs being allocated are directly related only to electric transmission, electric distribution, gas transmission, and intangible plant, the ratio shall be based on the sum of the total electric transmission plant, the total electric distribution plant, the total gas transmission plant, and the total intangible plant;
(53) If the costs being allocated are directly related only to electric transmission, electric distribution, gas distribution, and intangible plant, the ratio shall be based on the sum of the total electric transmission plant, the total electric distribution plant, the total gas distribution plant, and the total intangible plant;
(54) If the costs being allocated are directly related only to electric transmission, gas transmission, gas distribution, and intangible plant, the ratio shall be based on the sum of the total electric transmission plant, the total gas transmission plant, the total gas distribution plant, and the total intangible plant;
(55) If the costs being allocated are directly related only to electric distribution, gas transmission, gas distribution, and intangible plant, the ratio shall be based on the sum of the total electric distribution plant, the total gas transmission plant, the total gas distribution plant, and the total intangible plant;
(56) If the costs being allocated are directly related only to electric production, electric transmission, gas distribution, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, the total gas distribution plant, and the total intangible plant;
(57) If the costs being allocated are directly related only to electric production, electric transmission, electric distribution, gas distribution, and gas transmission, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, the total electric distribution plant, the total gas distribution plant, and the total gas transmission plant;
(58) If the costs being allocated are directly related only to electric production, electric transmission, electric distribution, gas transmission, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, the total electric distribution plant, the total gas transmission plant, and the total intangible plant;
(59) If the costs being allocated are directly related only to electric production, electric distribution, gas distribution, gas transmission, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total electric distribution plant, the total gas distribution plant, the total gas transmission plant, and the total intangible plant;
(60) If the costs being allocated are directly related only to electric production, electric transmission, gas distribution, gas transmission, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, the total gas distribution plant, the total gas transmission plant, and the total intangible plant;

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(61) If the costs being allocated are directly related only to electric production, electric transmission, electric distribution, gas distribution, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, the total electric distribution plant, the total gas distribution plant, and the total intangible plant;
(62) If the costs being allocated are directly related only to electric transmission, electric distribution, gas distribution, gas transmission, and intangible plant, the ratio shall be based on the sum of the total electric transmission plant, the total electric distribution plant, the total gas distribution plant, the total gas transmission plant, and the total intangible plant.

Total Phones Ratio - Based on the number of phones at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

Total Radios Ratio - Based on the number of radios at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

Total Computers Ratio - Based on the number of computers at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

Total Software Applications Users Ratio - Based on the number of users of a specific software application at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

Joint Operating Agreement Peak Hour Megawatt Load Ratio - Based on that certain Joint Operating Agreement among Northern States Power Company, a Minnesota corporation, Northern States Power Company, a Wisconsin corporation, Public Service Company of Colorado, Southwestern Public Service Company, and Xcel Energy Services Inc., as agent, dated as of October 1, 2004, as may be amended from time to time, that designates costs to be allocated based on peak hour of megawatt load for previous year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Joint Operating Agreement Labor Hours Ratio - Based on that certain Joint Operating Agreement among Northern States Power Company, a Minnesota corporation, Northern States Power Company, a Wisconsin corporation, Public Service Company of Colorado, Southwestern Public Service Company, and Xcel Energy Services Inc., as agent, dated as of October 1, 2004, as may be amended from time to time, that designates costs to be allocated based on labor hours at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company and the denominator of which is for all applicable Operating Companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

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Direct Labor Ratio – Based on fully-loaded direct-charged Rates and Regulation labor dollars to individual operating affiliates by the Rates and Regulation service function. The numerator of which is the fully-loaded direct-charges labor dollars to individual operating affiliates by Rates and Regulation service function and the denominator of which is the total fully-loaded direct charged labor dollars to all affiliates by the Rates and Regulation service function.

Northern States Power Company

Utility Allocation Factors
2022 Test Year Budget

Cost Categories	Allocation Method	Reasonableness of Allocation Method	2022 Test Year Percentages	
			Electric	Gas
FERC Accounts 901-917 (excluding commodity bad debt in FERC 904)	Customer bill counts for the electric and gas departments.	Using Customer bill counts is reasonable because costs recorded in FERC accounts 901-917 are customer related.	79.6146%	20.3854%
FERC 904 (commodity bad debt portion)	Average total electric and gas revenues for the previous four years	Using a revenue allocator is reasonable because commodity bad debt costs have a cost-causative relationship with uncollectible utility revenues.	76.9031%	11.3015%
FERC Accounts 920-924	3-factor allocation for the electric and gas departments.	Using a 3-factor allocation is reasonable because costs recorded in FERC accounts 920-924 are general in nature.	93.5946%	6.4054%
FERC Accounts 925-926	Operating labor for the electric and gas departments.	Using Operating labor is reasonable because costs recorded in FERC accounts 925-926 are employee related.	91.9159%	8.0841%
FERC Accounts 927-935	3-factor for the electric and gas departments.	Using a 3-factor allocation is reasonable because costs recorded in FERC accounts 927-937 are general in nature.	93.5946%	6.4054%

Administrative Service Agreement Charges

	Test Year Budget 2022	Total by Operating Co	Total for SPS and PSCo
NSPM charges to NSPW			
Productive Labor	$ 78,549		
Facilities Overheads	$ 7,243		
Labor Additives	$ 634		
Total Charges to NSPW		$ 86,426	
NSPW charges to NSPM			
Facilities Overheads	$ 22,950		
Labor Additives	$ 1,260		
Total Charges to NSPM		$ 24,210	
Charges from/to NSPW		$ 110,636	
NSPM charges to PSCo			
Facilities Overheads	$ 2,003		
Labor Additives	$ 156		
Total Charges to PSCo		$ 2,159	
PSCo charges to NSPM			
Facilities Overheads	$ 3,245		
Labor Additives	$ 14		
		$ 3,259	$ 5,418
NSPM charges to SPS			
Facilities Overheads	$ 286		
Labor Additives	$ 25		
Total Charges to SPS		$ 311	
SPS Charges to NSPM			
Facilities Overheads	$ 174		
Labor Additives	$ 3		
		$ 177	$ 488
Charges from/to Regulated Utility Operating Companies other than NSPW			$ 5,906

Definitions:
NSPM - Northern States Power Company-Minnesota
NSPW - Northern States Power Company-Wisconsin
PSCo - Public Service Company of Colorado
SPS - Southwestern Public Service

Non-Regulated Business Activity Significance

Fiscal Year Ended 12/31/2020

	Consolidated Total NSPM		All Other Non-regulated	
Operating revenues	$ 5,101,000	(1)(2)	$ 37,000	(1)(2)
Less: Interest charges and financing costs	(238,000)	(1)	-	(1)
Income tax expense	6,000	(1)	(1,000)	(1)
Net income	(591,000)	(1)	(8,000)	(1)
Subtotal	$ 4,278,000	(3)	$ 28,000	(3)
Add: Other expense, net	2,000	(2)	-	
Allowance for funds used during construction - equity	25,000	(2)	-	
Operating expenses	$ 4,305,000	(2)	$ 28,000	(3)
Less: Purchased cost of goods sold (COGS)	(1,911,000)	(3)	(22,000)	(2)
Operating expense, net of purchased COGS	$ 2,394,000	(3)	$ 6,000	(3)

Calculation of Purchased Fuel, Power & Gas Expense (Purchased COGS)				
Electric fuel and purchased power	$ 1,626,000	(2)		
Cost of natural gas sold and transported	263,000	(2)		
Cost of sales - other	22,000	(2)	$ 22,000	(2)
Purchased COGS	$ 1,911,000	(3)	$ 22,000	

Calculation of Operating Expenses excluding Purchased COGS		
Operating and maintenance expense	$ 1,191,000	(2)
Conservation program expenses	119,000	(2)
Depreciation and amortization	825,000	(2)
Taxes (other than income taxes)	259,000	(2)
Operating expense, net of purchased COGS	$ 2,394,000	(3)
Total Operating Expenses (excluding interest and income tax expenses)	$ 4,305,000	(2)

(1) From page 52 of Northern States Power Company's (NSPM) Form 10-K filed with the SEC for the fiscal year ended December 31, 2020. According to NSPM, the "All Other" column primarily includes appliance repair services, non-utility real estate activities, and revenues associated with processing solid waste into refuse-derived fuel.

(2) From page 26 of Northern States Power Company's (NSPM) Form 10-K filed with the SEC for the fiscal year ended December 31, 2020.

(3) Calculated number from above.

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, 2020 or

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

001-31387
(Commission File Number)

Northern States Power Company

Minnesota
(Exact name of registrant as specified in its charter)

Minnesota	**41-1967505**
(State or other jurisdiction of incorporation or organization)	(I.R.S. 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	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. ☐

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. 17, 2021, 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 2021 Annual Meeting of Shareholders which definitive Proxy Statement is expected to be filed with the SEC on or about April 6, 2021. 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).

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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.

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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	
D.C. Circuit	United States Court of Appeals for the District of Columbia Circuit
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
Minnesota District Court	U.S. District Court for the District of Minnesota
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
SDPUC	South Dakota Public Utilities Commission
SEC	Securities and Exchange Commission

Electric, Purchased Gas and Resource Adjustment Clauses	
CIP	Conservation improvement program
DSM	Demand side management
EIR	Environmental improvement rider
FCA	Fuel clause adjustment
GUIC	Gas utility infrastructure cost rider
PGA	Purchased gas adjustment
RDF	Renewable development fund
RER	Renewable energy rider
RES	Renewable energy standard
SEP	State energy policy rider
TCR	Transmission cost recovery adjustment

Other	
ADIT	Accumulated deferred income taxes
AFUDC	Allowance for funds used during construction
ALLETE	ALLETE, Inc.
ARO	Asset retirement obligation
ASC	FASB Accounting Standards Codification
ASU	FASB Accounting Standards Update
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
COVID-19	Novel coronavirus
CWA	Clean Water Act
CWIP	Construction work in progress
ELG	Effluent limitations guidelines
EMANI	European Mutual Association for Nuclear Insurance
ETR	Effective tax rate
FASB	Financial Accounting Standards Board
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
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
Paris Agreement	Establishes a framework for GHG mitigation actions by all countries ("nationally determined contributions")
PI	Prairie Island nuclear generating plant
PPA	Purchased power agreement
PTC	Production tax credit
REC	Renewable energy credit
ROE	Return on equity
ROFR	Right-of-first-refusal
ROU	Right-of-use
RTO	Regional Transmission Organization
S&P	Standard & Poor's Global Ratings
SERP	Supplemental executive retirement plan
SMMPA	Southern Minnesota Municipal Power Agency
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
WOTUS	Waters of the U.S.

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

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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 future sales, future bad debt expense, future operating performance, estimated base capital expenditures and financing plans, projected capital additions and forecasted annual revenue requirements with respect to rider filings and expectations regarding regulatory proceedings, 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.

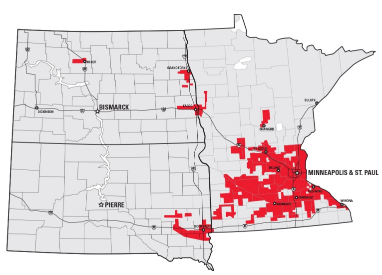
The following factors, in addition to those discussed elsewhere in this Annual Report on Form 10-K for the fiscal year ended Dec. 31, 2020 (including risk factors listed from time to time by NSP-Minnesota in reports filed with the SEC, including "Risk Factors" in Item 1A of this Annual Report on Form 10-K hereto), could cause actual results to differ materially from management expectations as suggested by such forward-looking information: uncertainty around the impacts and duration of the COVID-19 pandemic; operational safety, including our nuclear generation facilities; 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; ability to recover costs; changes in regulation; reductions in our credit ratings and the cost of maintaining certain contractual relationships; general economic conditions, including inflation rates, monetary fluctuations and their impact on capital expenditures and the ability of NSP-Minnesota and its subsidiaries 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; 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; natural disaster and resource depletion, including compliance with any accompanying legislative and regulatory changes; and costs of potential regulatory penalties.

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.

Company Overview

Electric customers	1.5 million
Natural gas customers	0.6 million
Total assets	$21.1 billion
Rate Base (estimated)	$12.4 billion
ROE (net income / average stockholder's equity)	9.20%
Electric generating capacity	8,137 MW
Gas storage capacity	17.1 Bcf
Electric transmission lines (conductor miles)	33,660 miles
Electric distribution lines (conductor miles)	80,508 miles
Natural gas transmission lines	80 miles
Natural gas distribution lines	10,629 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.

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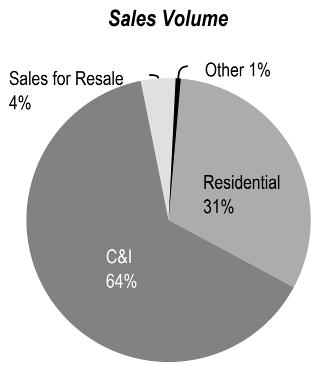
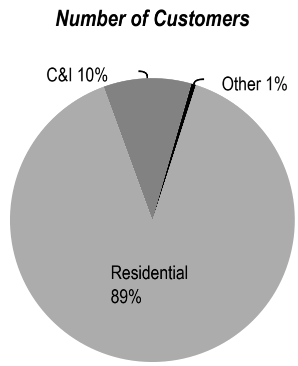
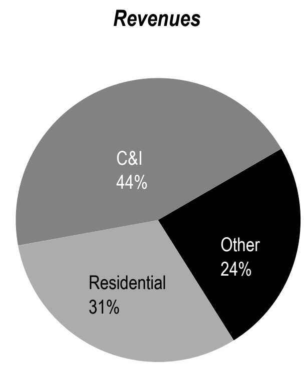
Electric Operations

Electric operations consist of energy supply, generation, transmission and distribution activities. NSP-Minnesota had electric sales volume of 33,738 (millions of KWh), 1.5 million customers and electric revenues of $4,571 (millions of dollars) for 2020.





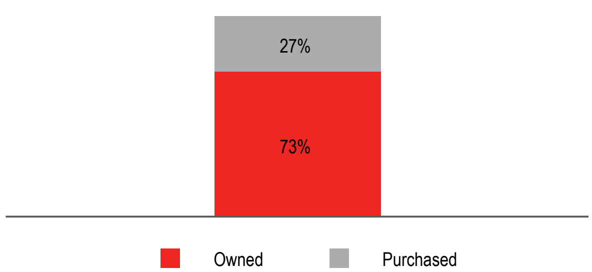


Sales/Revenue Statistics [(a)]

	2020	2019
KWH sales per retail customer	21,440	22,405
Revenue per retail customer	$ 2,306	$ 2,368
Residential revenue per KWh	13.36 ¢	13.22 ¢
Large C&I revenue per KWh	7.93 ¢	7.96 ¢
Small C&I revenue per KWh	10.24 ¢	10.15 ¢
Total retail revenue per KWh	10.76 ¢	10.57 ¢

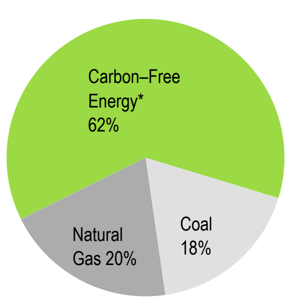
(a) See Note 6 to the consolidated financial statements for further information.

Owned and Purchased Energy Generation — 2020



Electric Energy Sources

Total electric generation by source (including energy market purchases) for the year ended Dec. 31, 2020:



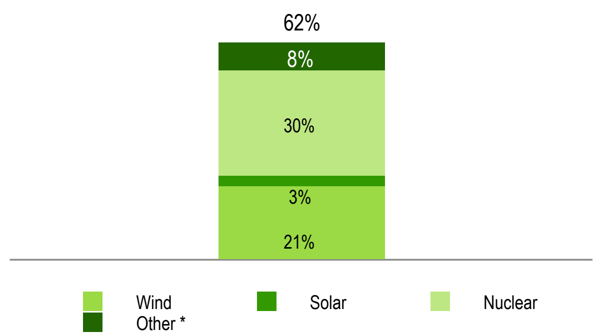
*Distributed generation from the Solar*Rewards® program is not included (approximately 43 million KWh for 2020).

Carbon–Free Energy — 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, weather, system demand and transmission constraints.

See Item 2 — Properties for further information.

Carbon–free energy as a percentage of total energy for 2020:



* Includes biomass and hydroelectric

Wind

Owned — Owned and operated wind farms with corresponding capacity:

2020		2019	
Wind Farms	Capacity [(a)]	Wind Farms	Capacity [(b)]
11	1,540 MW	7	1,079 MW

(a) Summer 2020 net dependable capacity.

(b) Summer 2019 net dependable capacity.

PPAs — Number of PPAs with capacity range:

2020		2019	
PPAs	Range	PPAs	Range
129	1 MW — 206 MW	131	1 MW — 206 MW

Capacity — Wind capacity:

2020	2019
3,348 MW	2,767 MW

Average Cost (Owned) — Average cost per MWh of wind energy from owned generation:

2020	2019
$23	$35

Average Cost (PPAs) — Average cost per MWh of wind energy under existing PPAs:

2020	2019
$38	$41

Wind Development

NSP-System placed approximately 460 MW of owned wind and a 200 MW PPA into service during 2020:

Project	Capacity
Blazing Star 1	200 MW (a)(b)
Crowned Ridge 2	192 MW (a)(b)
Community Wind North	26 MW (a)(b)
Jeffers	43 MW (a)(b)
PPA	200 MW (c)

(a) Summer 2020 net dependable capacity.
(b) Values disclosed are the maximum generation levels for these wind units. Capacity is attainable only when wind conditions are sufficiently available (on-demand net dependable capacity is zero).
(c) Based on contracted capacity.

NSP-System currently has approximately 1,450 MW of owned wind under development or construction. In addition, the NSP-System expects to add approximately 450 MW of planned PPAs.

Project	Capacity	Estimated Completion
Dakota Range	300 MW	2021
Freeborn	200 MW	2021
Blazing Star 2	200 MW	2021
Nobles	200 MW	2022
Pleasant Valley	200 MW	2024
Border Winds	150 MW	2024
Grand Meadow	100 MW	2023
Mower	99 MW	2021
Various PPAs	~450 MW	2021

Solar

Solar energy PPAs:

Type	Capacity
Distributed Generation	899 MW
Utility-Scale	268 MW
Total	1,167 MW

Average Cost (PPAs) — Average cost per MWh of solar energy under existing PPAs:

2020	2019
$90	$81

Nuclear

The NSP System has two nuclear plants (owned by NSP-Minnesota) with approximately 1,700 MW of total 2020 net summer dependable capacity. 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	
	Cost	Percent
2020	$ 0.80	51 %
2019	0.81	45

Other Carbon-Free Energy

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

See Item 2 — Properties for further information.

Fossil Fuel Energy — 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

NSP System owns and operates coal units with approximately 2,400 MW of total 2020 net summer dependable capacity.

Approved and proposed early coal plant retirements:

	Approved	
Year	Plant Unit	Capacity
2023	Sherco 2	682 MW
2026	Sherco 1	680 MW

	Proposed	
Year	Plant Unit	Capacity
2028	A.S. King	511 MW
2030	Sherco 3	517 MW (a)

(a) Based on 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:

	Coal (a)	
	Cost	Percent
2020	$ 1.97	31 %
2019	2.02	36

(a) Includes refuse-derived fuel and wood.

Natural Gas

The NSP System has eight natural gas plants with approximately 2,800 MW of total 2020 net summer dependable capacity.

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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:

	Natural Gas	
	Cost	Percent
2020	$ 2.67	17 %
2019	3.09	19

Capacity and Demand

Uninterrupted system peak demand and occurrence date:

System Peak Demand (in MW)			
2020		2019	
8,571	July 8	8,774	July 19

Transmission

Transmission lines deliver electricity over long distances from power sources to transmission substations closer to homes and businesses. 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 33,500 conductor miles of transmission lines across its service territory.

During 2020, NSP-Minnesota completed the following transmission projects:

Project	Miles	Size
Maple River-Red River	4	115 KV
Glenwood Douglas	20	69 KV

Upcoming transmission projects:

Project	Miles	Size	Completion Date
Hibbing Taconite Relocation	3	500 KV	2021
Huntley-Wilmarth	50	345 KV	2021
Helena Scott County	16	345 KV	2021
Baytown to Long lake	9	115 KV	2022
Centerville to Lincoln County	14	69 KV	2021

Distribution

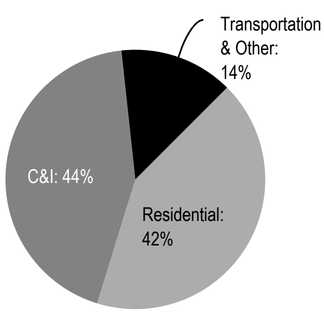
Distribution lines allow electricity to travel at lower voltages from substations directly to homes and businesses. NSP-Minnesota has a vast distribution network, owning and operating approximately 81,000 conductor miles of distribution lines across our service territory, both above ground and underground. 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.

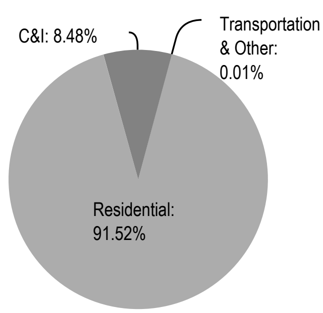
Natural Gas Operations

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 98,711 (thousands of MMBtu), 0.6 million customers and natural gas revenues of $493 (millions of dollars) for 2020.

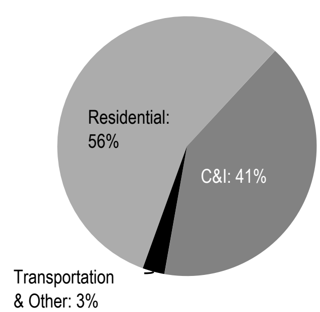
Deliveries



Number of Customers



Revenues



Sales/Revenue Statistics [(a)]

	2020	2019
MMBtu sales per retail customer	159.30	176.96
Revenue per retail customer	$ 901.93	$ 1,072.29
Residential revenue per MMBtu	6.66	7.04
C&I revenue per MMBtu	4.69	5.12
Transportation and other revenue per MMBtu	0.97	0.59

(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:

2020		2019	
MMBtu	Date	MMBtu	Date
871,921	Jan. 16	897,615	Feb. 25

Natural Gas Supply and Costs

NSP-Minnesota seeks natural gas supply, transportation and storage alternatives to yield a diversified portfolio, which increase flexibility, decrease 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:

2020	2019
$ 3.32	$ 3.71

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 construction and operation of certain new electric transmission facilities. State utilities commissions have also created resource planning programs that promote competition for electricity generation resources used to provide service to retail customers.

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.

Public Utility Regulation

See Item 7 for discussion of public utility regulation.

Environmental

Environmental Regulation

Our facilities are regulated by federal and state agencies that have jurisdiction over air emissions, water quality, wastewater discharges, solid wastes and hazardous 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 operate in compliance with applicable environmental standards and related monitoring and reporting requirements. However, it is not possible to determine when or to what extent additional facilities or modifications of 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 MGP and other sites if it is determined that prior compliance efforts are not sufficient.

NSP-Minnesota must comply with emission levels that may require the purchase of emission allowances.

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.

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In July 2019, the EPA adopted the Affordable Clean Energy rule, which required states to develop plans by 2022 for GHG reductions from coal-fired power plants. In a Jan. 19, 2021 decision, the U.S. Court of Appeals for the D.C. Circuit issued a decision vacating and remanding the Affordable Clean Energy rule. That decision, if not successfully appealed or reconsidered, would allow the EPA to proceed with alternate regulation of coal-fired power plants, either reviving the Clean Power Plan or proposing additional regulation. It is too early to predict an outcome, but new rules could require substantial additional investment, even in plants slated for retirement. NSP-Minnesota believes, based on prior state commission practices, the cost of these initiatives or replacement generation would be recoverable through rates.

NSP-Minnesota seeks to address climate change and potential climate change regulation through efforts to reduce its GHG emissions in a balanced, cost-effective manner.

Employees

As of Dec. 31, 2020, NSP-Minnesota had 3,144 full-time employees and eight part-time employees, of which 2,033 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. 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.

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.

At a threshold level, 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 and security risks.

Overall, 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 ensure appropriate risk oversight, as well as identification and consideration of new risks.

Risks Associated with Our Business

Operational Risks

Our natural gas and electric 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. 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.

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 necessary supplies.
- The impact of unusual or adverse weather conditions and natural disasters, including, but not limited to, tornadoes, icing events, floods and droughts.
- Performance below expected or contracted levels of output or efficiency (e.g., performance guarantees).
- Availability of replacement equipment.
- Availability of adequate water resources and ability to satisfy water intake and discharge requirements.
- 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 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.

Changing customer expectations and technologies are requiring significant investments in advanced grid infrastructure, which increases exposure to technology obsolescence. Additionally, evolving stakeholder preference for lower emissions from generation sources and end-uses, like heating, may put pressure on our ability to recover capital investments in natural gas generation and delivery.

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. Additionally, 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 are subject to longer-term availability of 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.

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

In the event fuel costs increase, customer demand could decline and bad debt expense may rise, which may have a material impact on our results of operations. Despite existing fuel 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 and supply shortages may not be fully resolved, which could cause disruptions in 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 could negatively impact 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.

Due to the inherent 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, including, without limitation, employee misconduct. If such controls 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.

Specialized knowledge is required of our technical employees for construction and operation of transmission, generation and distribution assets. Our business strategy is dependent on our ability to recruit, retain and motivate employees. There is competition and a tightening market for skilled employees. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical 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 could adversely impact 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 standards, progress payments, insurance requirements and security for performance. Poor vendor performance could impact ongoing operations, restoration operations, our reputation and could introduce financial risk or risks of fines.

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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. In 2020, 2019 and 2018 we paid $408 million, $467 million and $456 million of dividends to Xcel Energy Inc., respectively. 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 from our customers 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 our capital investment. Our rates are generally regulated and 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.

In a continued low interest rate environment there has been increased downward pressure on allowed ROE. Conversely, 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 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.

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, 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 and could 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 short-term commercial paper, issuing new securities or cause us to issue securities with unfavorable terms and conditions, such as higher interest rates. 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 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 various 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., Southwest Power Pool, Inc., PJM Interconnection, LLC, MISO and Electric Reliability Council of Texas), 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, 2020, Xcel Energy Inc. and its utility subsidiaries had approximately $19.6 billion of long-term debt and $1.0 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, 2020, Xcel Energy had guarantees outstanding with a $2 million maximum stated amount and immaterial exposure. Xcel Energy also had additional guarantees of $60 million at Dec. 31, 2020 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. 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 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 local, national and worldwide economic conditions, which correlates to customers/sales growth (decline). Economic conditions may be impacted by 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.

The global outbreak of COVID-19 is impacting countries, communities, supply chains and markets. A high degree of uncertainty continues to exist regarding the pandemic, the duration and magnitude of business restrictions, re-shut downs, if any, and the level and pace of economic recovery. While we are implementing contingency plans, there are no guarantees these plans will be sufficient to offset the impact of COVID-19.

Although the impact of the pandemic to the 2020 results was largely mitigated due to management's actions, we cannot ultimately predict whether it will have a material impact on our future liquidity, financial condition or results of operations. Nor can we predict the impact of the virus on the health of our employees, our supply chain or our ability to recover higher costs associated with managing through the pandemic. The impact of COVID-19 may exacerbate other risks discussed herein, which could have a material effect on us. The situation is evolving and additional impacts may arise.

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 already 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, severe 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. Xcel Energy 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 reliably serve our customers.

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

NSP-Minnesota participates in grid security and emergency response exercises (GridEx). These efforts, led by the NERC, test and further develop the coordination, threat sharing, and interaction between utilities and various government agencies relative to potential cyber and physical threats against the nation's electric grid.

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. Our 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, Nation States and individuals. 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 of 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 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.

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

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. The Biden Administration will establish a new nationally determined contribution for the United States. The Paris Agreement could result in future additional GHG reductions in the United States. In addition, the Biden Administration has announced plans to implement new climate change programs, including potential regulation of GHG emissions targeting the utility industry.

The Biden Administration has also announced a one year suspension of new oil and natural gas drilling on federal lands to allow for a review of oil and gas leasing regulations. The form of these regulations is uncertain, but, depending on the requirements imposed in the short and long term, they could impose substantial costs on our oil and gas customers or result in substantial increases to the cost of fuel we use in our electricity and gas businesses.

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 or 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.

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. The FERC can impose penalties of up to $1.3 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.

Environmental Risks

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.

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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.

Severe weather impacts our service territories, primarily when thunderstorms, flooding, tornadoes, wildfires and snow or ice storms 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. Periods of extreme temperatures could impact our ability to meet demand. Changes in precipitation resulting in droughts or water shortages could adversely affect our operations. Drought conditions also contribute to the increase in wildfire risk from our electric generation facilities.

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. 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	Fuel	Installed	MW [(a)]	
Steam:				
A.S. King-Bayport, MN, 1 Unit [(e)]	Coal	1968	511	
Sherco-Becker, MN [(f)]				
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:				
Border-Rolette County, ND, 75 Units	Wind	2015	148	(d)
Courtenay Wind-Stutsman County, ND, 100 Units	Wind	2016	190	(d)
Foxtail-Dickey County, ND, 75 Units	Wind	2019	150	(d)
Grand Meadow-Mower County, MN, 67 Units	Wind	2008	99	(d)
Lake Benton-Pipestone County, MN, 44 Units	Wind	2019	99	(d)
Nobles-Nobles County, MN, 134 Units	Wind	2010	197	(d)
Pleasant Valley-Mower County, MN, 100 Units	Wind	2015	196	(d)
Blazing Star 1-Lincoln County, MN, 100 Units	Wind	2020	200	(d)
Crowned Ridge 2-Grant County, SD, 88 Units	Wind	2020	192	(d)
Community Wind North-Lincoln County, MN, 12 Units	Wind	2020	26	(d)
Jeffers-Cottonwood County, MN, 20 Units	Wind	2020	43	(d)
		Total	8,137	

(a) Summer 2020 net dependable capacity.
(b) Based on NSP-Minnesota's ownership of 59%.
(c) Refuse-derived fuel is made from municipal solid waste.
(d) Values disclosed are the generation levels at the point-of-interconnection for these wind units. Capacity is attainable only when wind conditions are sufficiently available (on-demand net dependable capacity is zero).
(e) A.S. King is expected to be retired early in 2028.
(f) Sherco Unit 1, 2, and 3 are expected to be retired early in 2026, 2023 and 2030, respectively.

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Electric utility overhead and underground transmission and distribution lines (measured in conductor miles) at Dec. 31, 2020:

Conductor Miles	
Transmission	
500 KV	2,918
345 KV	13,151
230 KV	2,301
161 KV	674
115 KV	8,060
Less than 115 KV	6,556
Total Transmission	33,660
Distribution	
Less than 115 KV	80,508
Total	**114,168**

NSP-Minnesota had 352 electric utility transmission and distribution substations at Dec. 31, 2020.

Natural gas utility mains at Dec. 31, 2020:

Miles	
Transmission	80
Distribution	10,629

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 financial statements. Unless otherwise required by GAAP, legal fees are 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 2020 and 2019 were as follows:

(Millions of Dollars)	2020	2019
First quarter	$ 100	$ 95
Second quarter	105	96
Third quarter	109	94
Fourth quarter	106	194

ITEM 6 — SELECTED FINANCIAL DATA

Omitted per conditions set forth in general instructions I(1)(a) and (b) of Form 10-K for wholly owned subsidiaries (reduced disclosure format).

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 and the results of operations for the current year as set forth in general instructions 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, electric margin, natural gas margin, and ongoing earnings. Generally, a non-GAAP financial measure is a measure of a company's financial performance, financial position or cash flows that excludes (or includes) amounts 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.

Electric and Natural Gas Margins

Electric margin is presented as electric revenues less electric fuel and purchased power expenses. Natural gas margin is presented as natural gas revenues less the cost of natural gas sold and transported. Expenses incurred for electric fuel and purchased power and the cost of natural gas are generally recovered through various regulatory recovery mechanisms. As a result, changes in these expenses are generally offset in operating revenues.

Management believes electric and natural gas margins provide the most meaningful basis for evaluating our operations because they exclude the revenue impact of fluctuations in these expenses. These margins can be reconciled to operating income, a GAAP measure, by including other operating revenues, cost of sales-other, O&M expenses, conservation and DSM expenses, depreciation and amortization and taxes (other than income taxes).

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, 2020 and 2019, there were no adjustments to GAAP earnings and therefore GAAP earnings equal ongoing earnings.

Results of Operations

2020 Comparison with 2019

NSP-Minnesota's net income was approximately $591 million for 2020, compared with approximately $543 million for 2019. The increase in earnings was driven by higher electric margin (riders, wholesale transmission revenue and a sales true-up mechanism, which reflects lower sales due to COVID-19) and lower O&M expenses, partially offset by increased depreciation and lower natural gas margin.

Electric Margin

Electric revenues and fuel and purchased power expenses are impacted by fluctuations in the price of natural gas, coal and uranium. However, these fluctuations have minimal impact on margin due to fuel recovery mechanisms. In addition, electric customers receive a credit for PTCs generated, which reduce electric revenue and margin (offset by lower tax expense).

Electric Revenues and Margin:

(Millions of Dollars)	2020	2019
Electric revenues	$ 4,571	$ 4,506
Electric fuel and purchased power	(1,626)	(1,601)
Electric margin	$ 2,945	$ 2,905

Changes in Electric Margin:

(Millions of Dollars)	2020 vs. 2019
Non-fuel riders	$ 68
Wholesale transmission revenue (net)	21
Conservation incentive	9
Estimated impact of weather (net of decoupling/sales true-up)	1
PTCs flowed back to customers (offset by lower ETR)	(60)
Purchased capacity costs	(15)
Other (net)	16
Total increase in electric margin	$ 40

Natural Gas Margin

Natural gas expense varies with changing sales and cost of natural gas. However, fluctuations in the cost of natural gas have minimal impact on margin due to cost recovery mechanisms.

Natural gas revenues and margin:

(Millions of Dollars)	2020	2019
Natural gas revenues	$ 493	$ 571
Cost of natural gas sold and transported	(263)	(327)
Natural gas margin	$ 230	$ 244

Changes in natural gas margin:

(Millions of Dollars)	2020 vs. 2019
Estimated impact of weather	$ (12)
Infrastructure and integrity riders	(3)
Retail sales growth (excluding weather impact)	1
Total decrease in natural gas margin	$ (14)

Non-Fuel Operating Expenses and Other Items

O&M Expenses — O&M expenses decreased $12 million, or 1.0%, for 2020, largely reflecting cost mitigation efforts to offset the impact from COVID-19 and lower interchange billings with NSP-Wisconsin. Cost mitigation efforts included allocation of workforce, material and supply management, and timing of maintenance activities. The decrease was partially offset by incremental bad debt expense related to the COVID-19 pandemic and a commitment to fund the Minnesota payment plan credit program as agreed to in the Minnesota electric rate case stay-out.

Depreciation and Amortization — Depreciation and amortization expense increased $34 million, or 4.3%, for 2020. The increase was primarily due to the Foxtail, Blazing Star I, Lake Benton, Crowned Ridge, Community Wind North and Jeffers wind facilities going into service, as well as normal system expansion.

Income Taxes — Income tax expense decreased $53 million for 2020. The decrease was primarily driven by an increase in wind PTCs. Wind PTCs are credited to customers (recorded as a reduction to revenue) and do not have a material impact on net income. The ETR was (1.0)% for 2020 compared with 8.0% for 2019, largely due to the adjustments above.

Public Utility Regulation

The FERC and 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. Our utility subsidiaries request changes in rates for utility services through filings with governing commissions. Changes in operating costs can affect NSP-Minnesota's financial results, depending on the timing of rate case filings and implementation of final rates. Other factors affecting rate filings are new investments, sales, conservation and DSM 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.

See Rate Matters within Note 10 to the consolidated financial statements for further information.

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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. Pipeline safety compliance.
NDPSC	Retail rates, services and other aspects of electric and natural gas operations. 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.
EIR	Recovers costs of environmental improvement projects in Minnesota.
RDF	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.
RER	Recovers cost of renewable generation in North Dakota.
SEP	Recovers costs related to various energy policies approved by the Minnesota legislature.
TCR	Recovers costs for investments in electric transmission and distribution grid modernization.
Infrastructure Rider	Recovers costs for investments in generation and incremental property taxes in South Dakota.
FCA [(b)]	Minnesota, North Dakota and South Dakota include a FCA for monthly billing adjustments to recover changes in prudently incurred costs of fuel related items and purchased energy. Capacity costs are recovered through base rates and are not recovered through the FCA. MISO costs are generally recovered through either the FCA or base rates.
PGA	Provides for prospective monthly rate adjustments 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.
Sales True-up	In February 2021, NSP-Minnesota filed the 2020 sales true-up compliance report, resulting in a total surcharge of $119 million. An MPUC ruling is anticipated in the second quarter of 2021. The 2021 sales true-up mechanism, extended under the 2020 stay-out petition, will operate similarly to the currently approved sales true-up and apply to all customer classes. Under the stay-out petition, 2021 NSP-Minnesota jurisdictional earnings will be capped at 9.06% ROE. Any excess earnings will be refunded to customers.

(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.

(b) The MPUC changed the FCA process in Minnesota (effective in 2020). Each month, utilities collect amounts equal to baseline cost of energy set at the start of the plan year (base would be reset annually). Monthly variations to baseline costs are tracked and netted over a 12-month period. Utilities issue refunds above the baseline costs and can seek recovery of any overage.

Pending and Recently Concluded Regulatory Proceedings

Proceeding	Amount (in millions)	Filing Date	Approval
2020 North Dakota Electric Rate Case	$22	November 2020	Pending
2020 TCR Electric Rider	82	November 2019	Pending
2020 GUIC Natural Gas Rider	21	November 2019	Pending
2021 GUIC Natural Gas Rider	27	October 2020	Pending
2020 RES Electric Rider	102	November 2019	Pending
2021 RES Electric Rider	189	November 2020	Pending

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Additional Information:

2020 Minnesota Electric Rate Case and Stay-Out Alternative — In November 2020, NSP-Minnesota filed an electric rate case seeking a $597 million revenue increase over three years with the MPUC. The rate case is based on a requested ROE of 10.2% and a 52.5% equity ratio. NSP-Minnesota also filed a stay-out alternative in which it would withdraw its rate case filing.

In December 2020, the MPUC verbally approved the stay-out alternative petition, which includes the extension of the sales, capital and property tax true-up mechanisms and delays any increase to the Nuclear Decommissioning Trust annual accrual until Jan. 1, 2022.

Additionally, NSP-Minnesota agreed to not seek recovery of incremental COVID-19 related expenses, including bad debt expense, and committed to fund $18 million in a Residential Payment Plan Credit Program or other similar customer relief programs, as directed by the MPUC. NSP-Minnesota also agreed to an earnings test in which all earnings above an ROE of 9.06% in 2021 would be refunded to customers.

2020 North Dakota Electric Rate Case — In November 2020, NSP-Minnesota filed a request with the NDPSC for an overall increase in annual retail electric revenues of approximately $22 million, or an increase of 10.8%. The rate filing is based on a 2021 forecast test year, a requested ROE of 10.2%, an equity ratio of 52.50% and an electric rate base of approximately $677 million. Interim rates, subject to refund, of approximately $16 million were implemented on Jan. 5, 2021.

2020 TCR Electric Rider — In November 2019, NSP-Minnesota filed the TCR Rider based on an ROE of 9.06%. An MPUC decision is pending.

2020 GUIC Natural Gas Rider — In November 2019, NSP-Minnesota filed the GUIC Rider based on an ROE of 9.04%. An MPUC decision is pending.

2021 GUIC Natural Gas Rider — In October 2020, NSP-Minnesota filed the GUIC Rider based on an ROE of 9.04%. An MPUC decision is pending.

2020 RES Electric Rider — In November 2019, NSP-Minnesota filed the RES Rider. The requested amount includes a true-up for the 2019 rider of $38 million and the 2020 requested amount of $64 million. The filing included an ROE of 9.06%. An MPUC decision is pending.

2021 RES Electric Rider — In November 2020, NSP-Minnesota filed the RES Rider. The requested amount includes a true-up for the 2019 and 2020 rider of $96 million and the 2021 requested amount of $93 million. The filing included an ROE of 9.06%. An MPUC decision is pending.

Minnesota Resource Plan — In July 2019, NSP-Minnesota filed its Minnesota resource plan, which runs through 2034. The plan would result in an 80% carbon reduction by 2030 (from 2005) and puts NSP-Minnesota on a path to achieving its vision of being 100% carbon-free by 2050.

The updated preferred resource plan reflects the following:

- Retirement of all coal generation by 2030 with reduced operations at some units prior to retirement, including early retirement of the A.S. King coal plant (511 MW) in 2028 and the Sherco 3 coal plant (517 MW) in 2030.
- Extending the life of the Monticello nuclear plant from 2030 to 2040.
- Continuing to run the PI through current end of life (2033 and 2034).
- Construction of the Sherco combined cycle natural gas plant.
- The addition of 3,500 MW of solar.
- The addition of 2,250 MW of wind.
- 2,600 MW of firm peaking (combustion turbine, pumped hydro, battery storage, demand response, etc.).
- Achieving 780 GWh in energy efficiency savings annually through 2034.
- Adding 400 MW of incremental demand response by 2023, and a total of 1,500 MW of demand response by 2034.

Initial comments were submitted Feb. 11, 2021 and reply comments are due April 12, 2021. The MPUC is anticipated to make a final decision during 2021.

Minnesota Relief and Recovery — In 2020, the MPUC opened a docket and invited utilities in the state to submit potential projects that would create jobs and help jump start the economy to offset the impacts of COVID-19.

NSP-Minnesota's proposal included the following:

- Repower 651 MW of owned wind projects (capital investment of $750 million) as well as certain wind projects under PPAs.
- Acquire 120 MW repowered wind farm and buy-out of the remaining PPA from ALLETE for $210 million.
- Add solar facilities of 460 MW with an incremental investment of $550 million.
- Accelerate certain grid investment.
- Provide $150 million of incremental electric vehicle rebates.

In December 2020, the MPUC verbally approved the repowering of owned wind projects and 20 MW of wind projects under PPAs. These projects are estimated to save customers approximately $160 million over the next 25 years. The MPUC is expected to address the solar facilities, ALLETE PPA wind repowering acquisition and the electric vehicle proposal in the second half of 2021.

Purchased Power Arrangements and Transmission Service Provider

NSP-Minnesota expects to use power plants, power purchases, CIP/DSM options, new generation facilities and expansion of power plants to meet its system capacity requirements.

Purchased Power — NSP-Minnesota has contracts to purchase power from other utilities and IPPs. Long-term purchased power contracts for dispatchable resources typically require a capacity and an energy charge.

NSP-Minnesota makes short-term purchases to meet system requirements, replace company owned generation, meet operating reserve obligations or obtain energy at a lower cost.

Purchased Transmission Services — NSP-Minnesota and NSP-Wisconsin have contracts with MISO and other regional transmission service providers to deliver power and energy to their customers.

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Minnesota State ROFR Statute Complaint — In September 2017, LSP Transmission filed a complaint in the Minnesota District Court against the Minnesota Attorney General, MPUC and DOC. The complaint was in response to MISO assigning NSP-Minnesota and ITC Midwest, LLC to jointly own a new 345 KV transmission line from Mankato to Winnebago, Minnesota. The project is estimated to cost approximately $120 million and projected to be in-service by the end of 2021. It was assigned to NSP-Minnesota and ITC Midwest as the incumbent utilities, consistent with a Minnesota state ROFR statute.

The complaint challenged the constitutionality of the statute and is seeking declaratory judgment that the statute violates the Commerce Clause of the U.S. Constitution and should not be enforced. In June 2018, the Minnesota District Court granted Minnesota state agencies and NSP-Minnesota's motions to dismiss with prejudice. In February 2020, the Eighth Circuit Court of Appeals upheld the Minnesota District Court decision to dismiss. In June 2020, the Eighth Circuit denied LSP Transmission's petition for rehearing. In November 2020, LSP Transmission petitioned the U.S. Supreme Court to review its appeal. NSP-Minnesota filed a brief in opposition to this petition on Jan. 25, 2021.

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 disposal from Monticello and PI is disposed 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 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. 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.

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 and credit risk and to hedge sales and purchases.

NSP-Minnesota also engages in trading activity unrelated to hedging. 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.

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 of a particular instrument or commodity. All financial and commodity-related instruments, including derivatives, are subject to market risk.

See Note 8 to the consolidated financial statements for further information.

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 under the contracts underlying its derivatives, the contracts expose NSP-Minnesota to certain credit and non-performance risk.

Distress in the financial markets may impact counterparty risk, the fair value of the securities in the nuclear decommissioning fund and pension fund and NSP-Minnesota's ability to earn a return on short-term investments.

Commodity Price Risk — NSP-Minnesota is exposed to commodity price risk in its 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. NSP-Minnesota's risk management policy allows it 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.

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Fair value of net commodity trading contracts as of Dec. 31, 2020:

	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]	$ (2)	$ 1	$ 2	$ 2	$ 3
NSP-Minnesota [b]	(3)	3	(7)	(6)	(13)
	$ (5)	$ 4	$ (5)	$ (4)	$ (10)

	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]	$ 1	$ —	$ —	$ 1	$ 2

(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)	2020	2019
Fair value of commodity trading net contracts outstanding at Jan. 1	$ (2)	$ 16
Contracts realized or settled during the period	(11)	(11)
Commodity trading contract additions and changes during the period	5	(7)
Fair value of commodity trading net contracts outstanding at Dec. 31	$ (8)	$ (2)

At Dec. 31, 2020, a 10% increase in market prices for commodity trading contracts through the forward curve would increase pretax income from continuing operations by approximately $6 million, whereas a 10% decrease would decrease pretax income from continuing operations by approximately $6 million. At Dec. 31, 2019, a 10% increase in market prices for commodity trading contracts would increase pretax income from continuing operations by approximately $6 million, whereas a 10% decrease would decrease pretax income from continuing operations by approximately $6 million. 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 that have been entered into, but not closed, using an industry standard methodology known as VaR. VaR expresses the potential change in fair value on 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 purchase, 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	VaR Limit	Average	High	Low
2020	$ 1	$ 3	$ 1	$ 2	$ 1
2019	< 1	3	1	1	< 1

Nuclear Fuel Supply — NSP-Minnesota has contracted for approximately 11% of its 2021 enriched nuclear material requirements from sources that could be impacted by sanctions against entities doing business with Iran. Those sanctions may impact the supply of enriched nuclear material supplied from Russia. Long-term, through 2030, NSP-Minnesota is scheduled to take delivery of approximately 28% of its average enriched nuclear material requirements from these sources. NSP-Minnesota is able to manage nuclear fuel supply with alternate potential sources. NSP-Minnesota periodically assesses if further actions are required to assure a secure supply of enriched nuclear material.

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 such as swaps, caps, collars and put or call options.

A 100-basis-point change in the benchmark rate on NSP-Minnesota's variable rate debt would impact pretax interest expense annually by an immaterial amount in 2020 and 2019, respectively.

NSP-Minnesota maintains a nuclear decommissioning fund, as required by the NRC. The nuclear decommissioning fund is subject to interest rate risk 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. Realized and unrealized gains on the decommissioning fund investments are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs. 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.

Changes in discount rates and expected return on plan assets impact the value of pension and postretirement plan assets and/or benefit costs.

See Note 8 to the consolidated financial statements for further information.

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 monitor these policies to reflect changes and scope of operations.

At Dec. 31, 2020, a 10% increase in commodity prices would have resulted in an increase in credit exposure of $9 million, while a decrease in prices of 10% would have resulted in an increase in credit exposure of $1 million. At Dec. 31, 2019, a 10% increase in commodity prices would have resulted in an increase in credit exposure of $21 million, while a decrease in prices of 10% would have resulted in an increase in credit exposure of $8 million.

NSP-Minnesota conducts credit reviews for all 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

NSP-Minnesota uses derivative contracts such as futures, forwards, interest rate swaps, options and FTRs to manage commodity price and interest rate risk. Derivative contracts, with the exception of those designated as normal purchase-normal sale contracts, 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.

Commodity Derivatives — NSP-Minnesota continuously monitors the creditworthiness of the counterparties to its commodity derivative contracts and assesses each counterparty's ability to perform on the transactions. The impact of discounting commodity derivative assets for counterparty credit risk was not material to the fair value of commodity derivative assets at Dec. 31, 2020.

Adjustments to fair value for credit risk of commodity trading instruments are recorded in electric revenues. Credit risk adjustments for other commodity derivative instruments are recorded as other comprehensive income or deferred as regulatory assets and liabilities. Classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms. The impact of discounting commodity derivative liabilities for credit risk was immaterial at Dec. 31, 2020.

See Notes 8 and 9 to the consolidated financial statements for further information.

Natural Gas Fuel and Electricity Purchases

In February 2021, the United States experienced winter storm Uri and extreme cold temperatures in the central United States. This severe weather event increased the demand for natural gas used in our electric and natural gas businesses. Certain operational assets were impacted by extreme cold temperatures and safety protocols and the cold further impacted the availability of renewable generation across the region (which typically acts as a hedge against commodity prices) contributing to extremely high market prices for natural gas and electricity. As a result, electric and natural gas fuel costs increased approximately $300 million. These amounts are preliminary estimates through Feb. 16, 2021 and are subject to final settlement.

NSP-Minnesota has fuel recovery mechanisms in all of its states to recover the increased cost of natural gas and electricity. However, given the impact of these higher costs to our customers during a pandemic, we expect our regulators to undertake a heightened review and we intend to work with our commissions to recover these costs over time to help mitigate the impacts on customer bills. NSP-Minnesota is taking action to increase planned debt issuances to ensure adequate liquidity for the timing difference between fuel payments and revenue collection from customers and to address any potential need to post collateral.

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.

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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, 2020. 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, 2020, NSP-Minnesota's internal control over financial reporting is effective at the reasonable assurance level based on those criteria.

/s/ BEN FOWKE	/s/ BRIAN J. VAN ABEL
Ben Fowke	Brian J. Van Abel
Chairman, Chief Executive Officer and Director	Executive Vice President, Chief Financial Officer and Director
Feb. 17, 2021	Feb. 17, 2021

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the stockholder and 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, 2020 and 2019, the related consolidated statements of income, comprehensive income, cash flows and common stockholder's equity, for each of the three years in the period ended December 31, 2020, 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, 2020 and 2019, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2020, 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 memorandums, filings made by intervenors, 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 17, 2021

We have served as the Company's auditor since 2002.

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NSP-MINNESOTA AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
(amounts in millions)

	Year Ended Dec. 31		
	2020	2019	2018
Operating revenues			
Electric, non-affiliates	$ 4,131	$ 4,049	$ 4,034
Electric, affiliates	440	457	474
Natural gas	493	571	583
Other	37	35	31
Total operating revenues	5,101	5,112	5,122
Operating expenses			
Electric fuel and purchased power	1,626	1,601	1,701
Cost of natural gas sold and transported	263	327	345
Cost of sales — other	22	23	20
Operating and maintenance expenses	1,191	1,203	1,223
Conservation program expenses	119	120	118
Depreciation and amortization	825	791	742
Taxes (other than income taxes)	259	260	257
Total operating expenses	4,305	4,325	4,406
Operating income	796	787	716
Other income (expense), net	2	(1)	(7)
Allowance for funds used during construction — equity	25	25	24
Interest charges and financing costs			
Interest charges — includes other financing costs of $8, $7 and $7, respectively	249	233	227
Allowance for funds used during construction — debt	(11)	(12)	(13)
Total interest charges and financing costs	238	221	214
Income before income taxes	585	590	519
Income tax (benefit) expense	(6)	47	27
Net income	$ 591	$ 543	$ 492

See Notes to Consolidated Financial Statements

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NSP-MINNESOTA AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(amounts in millions)

	Year Ended Dec. 31		
	2020	2019	2018
Net income	$ 591	$ 543	$ 492
Other comprehensive income			
Derivative instruments:			
Reclassification of losses to net income, net of tax of $—	1	—	1
Total other comprehensive income	1	—	1
Total comprehensive income	$ 592	$ 543	$ 493

See Notes to Consolidated Financial Statements

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NSP-MINNESOTA AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(amounts in millions)

	Year Ended Dec. 31		
	2020	2019	2018
Operating activities			
Net income	$ 591	$ 543	$ 492
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation and amortization	831	798	748
Nuclear fuel amortization	123	119	122
Deferred income taxes	(67)	(39)	41
Allowance for equity funds used during construction	(25)	(25)	(24)
Provision for bad debts	24	13	16
Net realized and unrealized hedging and derivative transactions	(4)	19	27
Changes in operating assets and liabilities:			
Accounts receivable	(55)	15	(43)
Accrued unbilled revenues	1	20	7
Inventories	(14)	(29)	(21)
Other current assets	(9)	(3)	95
Accounts payable	(1)	(13)	11
Net regulatory assets and liabilities	(87)	(140)	182
Other current liabilities	(58)	(12)	(64)
Pension and other employee benefit obligations	(54)	(49)	(76)
Other, net	(4)	(48)	(31)
Net cash provided by operating activities	1,192	1,169	1,482
Investing activities			
Capital/construction expenditures	(1,901)	(1,417)	(1,150)
Purchase of investment securities	(1,398)	(995)	(853)
Proceeds from the sale of investment securities	1,378	975	833
Investments in utility money pool arrangement	(718)	(219)	(805)
Repayments from utility money pool arrangement	718	219	805
Other, net	1	(3)	(4)
Net cash used in investing activities	(1,920)	(1,440)	(1,174)
Financing activities			
Proceeds from (repayments of) short-term borrowings, net	149	(120)	130
Borrowings under utility money pool arrangement	136	696	479
Repayments under utility money pool arrangement	(136)	(696)	(564)
Proceeds from issuance of long-term debt	677	580	—
Repayment of long-term debt	(300)	—	—
Capital contributions from parent	527	354	109
Dividends paid to parent	(408)	(467)	(456)
Other, net	3	—	—
Net cash provided by (used in) financing activities	648	347	(302)
Net change in cash and cash equivalents	(80)	76	6
Cash and cash equivalents at beginning of period	126	50	44
Cash and cash equivalents at end of period	$ 46	$ 126	$ 50
Supplemental disclosure of cash flow information:			
Cash paid for interest (net of amounts capitalized)	$ (230)	$ (209)	$ (207)
Cash (paid) received for income taxes, net	(53)	(105)	89
Supplemental disclosure of non-cash investing and financing transactions:			
Accrued property, plant and equipment additions	$ 74	$ 95	$ 93
Inventory transfers to property, plant and equipment	24	24	61
Operating lease right-of-use assets	2	629	—
Allowance for equity funds used during construction	25	25	24

See Notes to Consolidated Financial Statements

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NSP-MINNESOTA AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(amounts in millions, except share and per share data)

	Dec. 31 2020	Dec. 31 2019
Assets		
Current assets		
Cash and cash equivalents	$ 46	$ 126
Accounts receivable, net	392	360
Accounts receivable from affiliates	32	44
Accrued unbilled revenues	248	251
Inventories	295	305
Regulatory assets	411	320
Derivative instruments	17	32
Prepayments and other	50	31
Total current assets	1,491	1,469
Property, plant and equipment, net	15,308	14,244
Other assets		
Nuclear decommissioning fund and other investments	2,830	2,495
Regulatory assets	924	1,125
Derivative instruments	5	9
Operating lease right-of-use assets	488	564
Other	14	10
Total other assets	4,261	4,203
Total assets	$ 21,060	$ 19,916
Liabilities and Equity		
Current liabilities		
Current portion of long-term debt	$ —	$ 300
Short-term debt	179	30
Accounts payable	438	388
Accounts payable to affiliates	66	76
Regulatory liabilities	123	141
Taxes accrued	263	232
Accrued interest	72	72
Dividends payable to parent	106	94
Derivative instruments	22	25
Operating lease liabilities	85	80
Other	154	202
Total current liabilities	1,508	1,640
Deferred credits and other liabilities		
Deferred income taxes	1,840	1,779
Deferred investment tax credits	18	20
Regulatory liabilities	1,896	1,937
Asset retirement obligations	2,350	2,280
Derivative instruments	71	110
Pension and employee benefit obligations	192	236
Operating lease liabilities	443	526
Other	69	86
Total deferred credits and other liabilities	6,879	6,974
Commitments and contingencies		
Capitalization		
Long-term debt	5,904	5,221
Common stock — 5,000,000 shares authorized of $0.01 par value; 1,000,000 shares outstanding at Dec. 31, 2020 and Dec. 31, 2019, respectively	—	—
Additional paid in capital	4,585	4,068
Retained earnings	2,206	2,036
Accumulated other comprehensive loss	(22)	(23)
Total common stockholder's equity	6,769	6,081
Total liabilities and equity	$ 21,060	$ 19,916

See Notes to Consolidated Financial Statements

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NSP-MINNESOTA AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
(amounts in millions, except share data)

	Common Stock					
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Common Stockholder's Equity
Balance at Dec. 31, 2017	1,000,000	$ —	$ 3,580	$ 1,920	$ (24)	$ 5,476
Net income				492		492
Other comprehensive income					1	1
Dividends declared to parent				(440)		(440)
Contribution of capital by parent			44			44
Balance at Dec. 31, 2018	1,000,000	$ —	$ 3,624	$ 1,972	$ (23)	$ 5,573
Net income				543		543
Dividends declared to parent				(479)		(479)
Contribution of capital by parent			444			444
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

See Notes to Consolidated Financial Statements

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 in 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 the 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, 2020 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 on 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 of recovering deferred costs and returning deferred credits are based on specific ratemaking decisions or precedent for each item. 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 from its balance sheet. 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 financial statements. NSP-Minnesota defers income taxes 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 NSP-Minnesota's tax rate changes are generally subject to a normalization method of accounting. Therefore, the revaluation of most of its net deferred taxes upon a tax rate reduction results in the establishment of a net regulatory liability, which would be refundable to utility customers over the remaining life of the related assets. NSP-Minnesota anticipates that a tax rate increase would result in the establishment of a regulatory asset, subject to regulatory approval.

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 it over the book depreciable lives of the related property. The requirement to defer and amortize tax credits only applies to federal ITCs related to public utility property. Utility rate regulation also has resulted in the recognition of regulatory assets and liabilities related to income taxes. 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.

NSP-Minnesota follows the applicable accounting guidance to measure and disclose uncertain tax positions that it has taken or expects to take in its income tax returns. NSP-Minnesota recognizes a tax position in its 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.

NSP-Minnesota reports interest and penalties related to income taxes 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.

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Maintenance and replacement of items determined to be less than a unit of property are charged to operating expenses as incurred. Planned maintenance activities are charged to operating expense unless the cost represents the acquisition of an additional unit of property or the replacement of an existing unit of property.

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.

NSP-Minnesota records depreciation expense using the straight-line method over the plant's 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 recovered in rates as authorized by the appropriate regulatory entities. The amount of removal costs are based on current factors used in existing depreciation rates. 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 3.7% for 2020, 3.7% for 2019 and 3.6% for 2018.

See Note 3 for further information.

AROs — NSP-Minnesota accounts for AROs under accounting guidance that requires a liability for the fair value of an ARO to be recognized in the period in which it is incurred if it can be reasonably estimated, with the offsetting associated asset retirement 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 depreciated over the useful life of the long-lived asset. Changes resulting from revisions to the timing or amount 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 performed at least every three years and submitted to the state commissions for approval.

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 liability can be reasonably estimated. Costs are deferred as a regulatory asset if it is probable that the costs will be recovered from customers in future rates. Otherwise, the costs are expensed. If an environmental expense is related to facilities currently in use, such as 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 proceeds. 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.

NSP-Minnesota does not recognize a separate financing component of its collections from customers as contract terms are short-term in nature. NSP-Minnesota presents its revenues 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 three 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, 2020 and 2019, the allowance for bad debts was $33 million and $23 million, respectively.

Inventory — Inventory is recorded at average cost and consisted of the following:

(Millions of Dollars)	Dec. 31, 2020	Dec. 31, 2019
Inventories		
Materials and supplies	$ 178	$ 176
Fuel	90	103
Natural gas	27	26
Total inventories	$ 295	$ 305

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. Cash equivalents are recorded at cost plus accrued interest; money market funds are measured using quoted NAVs.

For interest rate derivatives, quoted prices based primarily on observable market interest rate curves are used to establish 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, NSP-Minnesota may use quoted prices for similar contracts or internally prepared valuation models 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 estimate fair value for each security.

See Notes 8 and 9 for further information.

Derivative Instruments — NSP-Minnesota uses derivative instruments in connection with its interest rate, utility commodity price and commodity trading activities, 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 and interest rate hedging transactions are recorded as a component of interest expense.

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 a derivative exists and/or whether an instrument may be exempted from derivative accounting if designated as a normal purchase or normal sale.

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. AFUDC 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 for establishing utility rates.

Alternative Revenue — Certain rate rider mechanisms (including decoupling and CIP/DSM programs) qualify as alternative revenue programs. These mechanisms arise from costs imposed upon the utility by action of a regulator or legislative body related to an environmental, public safety or other mandate. When certain criteria are met, including expected collection within 24 months, revenue is recognized equal to the revenue requirement, 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 DSM and 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.

Emission Allowances — Emission allowances are recorded at cost, including broker commission fees. The inventory accounting model is utilized for all emission allowances and 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. 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 shown on a net basis in electric operating revenues in the consolidated statements of income.

2. Accounting Pronouncements

Recently Adopted

Credit Losses — In 2016, the FASB issued *Financial Instruments - Credit Losses, Topic 326 (ASC Topic 326),* which changes how entities account for losses on receivables and certain other assets. The guidance requires use of a current expected credit loss model, which may result in earlier recognition of credit losses than under previous accounting standards.

NSP-Minnesota implemented the guidance using a modified-retrospective approach, recognizing a cumulative effect charge of $1 million (after tax) to retained earnings on Jan. 1, 2020. Other than first-time recognition of an allowance for bad debts on accrued unbilled revenues, the Jan. 1, 2020 adoption of ASC Topic 326 did not have a significant impact on NSP-Minnesota's consolidated financial statements.

3. Property, Plant and Equipment

Major classes of property, plant and equipment

(Millions of Dollars)	Dec. 31, 2020	Dec. 31, 2019
Property, plant and equipment, net		
Electric plant	$ 18,948	$ 18,519
Natural gas plant	1,707	1,563
Common and other property	955	887
Plant to be retired [(a)]	136	—
CWIP	1,150	846
Total property, plant and equipment	22,896	21,815
Less accumulated depreciation	(7,898)	(7,945)
Nuclear fuel	2,970	2,910
Less accumulated amortization	(2,660)	(2,536)
Property, plant and equipment, net	$ 15,308	$ 14,244

(a) Includes regulator-approved retirements of Sherco Units 1 and 2.

Joint Ownership of Generation and Transmission Facilities

Jointly owned assets as of Dec. 31, 2020:

(Millions of Dollars, Except Percent Owned)	Plant in Service	Accumulated Depreciation	CWIP	Percent Owned
Electric generation:				
Sherco Unit 3	$ 601	$ 435	$ 2	59 %
Sherco common facilities	149	108	5	80
Sherco substation	5	3	—	59
Electric transmission:				
Grand Meadow	11	3	—	50
CapX2020	954	108	33	51
Total	$ 1,720	$ 657	$ 40	

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, 2020		Dec. 31, 2019	
Regulatory Assets			Current	Noncurrent	Current	Noncurrent
Pension and retiree medical obligations	9	Various	$ 26	$ 364	$ 28	$ 378
Excess deferred taxes — TCJA	7	Various	10	122	10	132
Recoverable deferred taxes on AFUDC		Plant lives	—	113	—	115
Benson biomass PPA termination and asset purchase		Nine years	10	65	9	73
PI extended power uprate		14 years	3	49	3	53
Contract valuation adjustments [(a)]	1, 8	Term of related contract	16	48	16	62
Laurentian biomass PPA termination		Three years	18	36	19	54
Purchased power contracts costs		Term of related contract	4	32	3	36
Sales true-up and revenue decoupling		One to two years	101	28	54	16
Conservation programs [(b)]	1	One to two years	14	23	18	13
Deferred purchased natural gas and electricity energy costs		One to two years	8	18	6	6
Losses on reacquired debt		Term of related debt	1	12	2	14
Nuclear refueling outage costs	1	One to two years	28	10	43	17
Environmental remediation costs	1, 10	Pending future rate cases	1	9	1	12
State commission adjustments		Plant lives	—	3	—	3
Renewable resources and environmental initiatives		One to two years	129	1	72	1
Gas pipeline inspection and remediation costs		One to two years	26	—	26	—
Net AROs [(c)]	1, 10	Various	—	(32)	—	118
Other		Various	16	23	10	22
Total regulatory assets			$ 411	$ 924	$ 320	$ 1,125

(a) Includes the fair value of certain long-term PPAs used to meet energy capacity requirements and valuation adjustments on natural gas commodity purchases.

(b) Includes costs for conservation programs, as well as incentives allowed in certain jurisdictions.

(c) Includes amounts recorded for future recovery of AROs, less amounts recovered through nuclear decommissioning accruals and gains from decommissioning investments.

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Components of regulatory liabilities:

(Millions of Dollars)	See Note(s)	Remaining Amortization Period	Dec. 31, 2020		Dec. 31, 2019	
Regulatory Liabilities			Current	Noncurrent	Current	Noncurrent
Deferred income tax adjustments and TCJA refunds [(a)]	7	Various	$ 9	$ 1,326	$ 13	$ 1,389
Plant removal costs	1, 10	Various	—	544	—	520
ITC deferrals	1	Various	—	8	—	8
Contract valuation adjustments [(b)]	1, 8	Less than one year	12	—	8	—
DOE Settlement		Less than one year	11	—	27	—
Deferred electric energy costs		Less than one year	8	—	24	—
Renewable resources and environmental initiatives		Less than one year	5	—	—	—
Other		Various	78	18	69	20
Total regulatory liabilities [(c)]			$ 123	$ 1,896	$ 141	$ 1,937

(a) Includes the revaluation of recoverable/regulated plant ADIT and revaluation impact of non-plant ADIT due to the TCJA.

(b) Includes the fair value of certain long-term PPAs used to meet energy capacity requirements and valuation adjustments on natural gas commodity purchases.

(c) Revenue subject for refund of $17 million and $24 million for 2020 and 2019, respectively, is included in other current liabilities.

At Dec. 31, 2020 and 2019, NSP-Minnesota's regulatory assets not earning a return primarily included the unfunded portion of pension and retiree medical obligations and net AROs. In addition, regulatory assets included $399 million and $235 million at Dec. 31, 2020 and 2019, respectively, of past expenditures not earning a return. Amounts are related to sales true-up and revenue decoupling, purchased natural gas and electric energy costs, various renewable resources and certain environmental initiatives.

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 for NSP-Minnesota were as follows:

(Millions of Dollars, Except Interest Rates)	Three Months Ended Dec. 31, 2020	Year Ended Dec. 31 2020	2019	2018
Borrowing limit	$ 250	$ 250	$ 250	$ 250
Amount outstanding at period end	—	—	—	—
Average amount outstanding	—	3	32	17
Maximum amount outstanding	18	116	250	143
Weighted average interest rate, computed on a daily basis	0.08 %	1.53 %	2.05 %	1.96 %
Weighted average interest rate at period end	N/A	N/A	N/A	N/A

Commercial Paper — Commercial paper outstanding for NSP-Minnesota was as follows:

(Millions of Dollars, Except Interest Rates)	Three Months Ended Dec. 31, 2020	Year Ended Dec. 31 2020	2019	2018
Borrowing limit	$ 500	$ 500	$ 500	$ 500
Amount outstanding at period end	179	179	30	150
Average amount outstanding	13	10	71	38
Maximum amount outstanding	179	179	317	198
Weighted average interest rate, computed on a daily basis	0.17 %	1.25 %	2.59 %	2.08 %
Weighted average interest rate at end of period	0.18	0.18	2.05	2.97

Letters of Credit — NSP-Minnesota uses letters of credit, typically with terms of one year, to provide financial guarantees for certain operating obligations. At both Dec. 31, 2020 and 2019, there were $10 million of letters of credit outstanding under the credit facility. 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 in an aggregate amount 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.

Amended Credit Agreement — In June 2019, NSP-Minnesota entered into an amended five-year credit agreement with a syndicate of banks. The amended credit agreement has substantially the same terms and conditions as the prior credit agreement with the exception of the maturity, which is June 2024.

Features of NSP-Minnesota's credit facility:

Debt-to-Total Capitalization Ratio [(a)] 2020	2019	Amount Facility May Be Increased (millions)	Additional Periods for Which a One-Year Extension May Be Requested [(b)]
47 %	48 %	$ 100	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, 2020, NSP-Minnesota was in compliance with all financial covenants on its debt agreements.

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NSP-Minnesota had the following committed credit facility available as of Dec. 31, 2020 (in millions):

Credit Facility [(a)]	Drawn [(b)]	Available
$ 500	$ 189	$ 311

(a) This credit facility matures in June 2024.
(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, 2020 and 2019.

Bilateral Credit Agreement

In March 2019, NSP-Minnesota entered into a one-year uncommitted bilateral credit agreement. The agreement is limited in use to support letters of credit. In March 2020, NSP-Minnesota renewed its bilateral credit agreement for an additional one-year term.

As of Dec. 31, 2020, NSP-Minnesota's outstanding letters of credit under the Bilateral Credit Agreement were as follows (in millions):

Limit	Amount Outstanding	Available
$ 75	$ 49	$ 26

Long-Term Borrowings and Other Financing Instruments

Generally, all property of NSP-Minnesota is subject to the lien of its first mortgage indenture. 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 (millions of dollars):

Financing Instrument	Interest Rate	Maturity Date	2020	2019
First mortgage bonds	2.20 %	Aug. 15, 2020	$ —	$ 300
First mortgage bonds	2.15	Aug. 15, 2022	300	300
First mortgage bonds	2.60	May 15, 2023	400	400
First mortgage bonds	7.13	July 1, 2025	250	250
First mortgage bonds	6.50	March 1, 2028	150	150
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	4.13	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	3.60	Sept. 15, 2047	600	600
First mortgage bonds [(b)]	2.90	March 1, 2050	600	600
First mortgage bonds [(a)]	2.60	June 1, 2051	700	—
Unamortized discount			(42)	(31)
Unamortized debt issuance cost			(54)	(48)
Current maturities			—	(300)
Total long-term debt			$ 5,904	$ 5,221

(a) 2020 financing.
(b) 2019 financing.

Maturities of long-term debt are as follows:

(Millions of Dollars)	
2021	$ —
2022	300
2023	400
2024	—
2025	250

Deferred Financing Costs — Deferred financing costs of approximately $54 million and $48 million, net of amortization, are presented as a deduction from the carrying amount of long-term debt at Dec. 31, 2020 and 2019, 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, 2020:

Equity to Total Capitalization Ratio Required Range		Equity to Total Capitalization Ratio Actual
Low	High	2020
47.1 %	57.5 %	52.7 %

Unrestricted Retained Earnings	Total Capitalization	Limit on Total Capitalization
$ 1 billion	$ 13 billion	$ 13 billion

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, 2020			
(Millions of Dollars)	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

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(Millions of Dollars)	Year Ended Dec. 31, 2019 Electric	Natural Gas	All Other	Total
Major revenue types				
Revenue from contracts with customers:				
Residential	$ 1,280	$ 303	$ 30	$ 1,613
C&I	2,054	229	—	2,283
Other	33	—	5	38
Total retail	3,367	532	35	3,934
Wholesale	210	—	—	210
Transmission	216	—	—	216
Interchange	459	—	—	459
Other	12	9	—	21
Total revenue from contracts with customers	4,264	541	35	4,840
Alternative revenue and other	242	30	—	272
Total revenues	$ 4,506	$ 571	$ 35	$ 5,112

(Millions of Dollars)	Year Ended Dec. 31, 2018 Electric	Natural Gas	All Other	Total
Major revenue types				
Revenue from contracts with customers:				
Residential	$ 1,308	$ 309	$ 27	$ 1,644
C&I	2,052	239	1	2,292
Other	37	—	3	40
Total retail	3,397	548	31	3,976
Wholesale	189	—	—	189
Transmission	238	—	—	238
Interchange	474	—	—	474
Other	28	12	—	40
Total revenue from contracts with customers	4,326	560	31	4,917
Alternative revenue and other	182	23	—	205
Total revenues	$ 4,508	$ 583	$ 31	$ 5,122

7. Income Taxes

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.

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	July 2021

Additionally, the statute of limitations related to the federal tax loss carryback claim referenced above 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.

In 2017, the IRS concluded the audit of tax years 2012 and 2013 and proposed an adjustment that would impact Xcel Energy's NOL and ETR. Xcel Energy filed a protest with the IRS. In April 2020, Xcel Energy and Appeals reached an agreement and no material adjustments were required.

In 2018, the IRS began an audit of tax years 2014 - 2016. In July 2020, Xcel Energy and the IRS reached an agreement and the related benefit was recognized.

State Audits — NSP-Minnesota is a member of the Xcel Energy affiliated group that files consolidated state income tax returns. As of Dec. 31, 2020, NSP-Minnesota's earliest open tax year subject to examination by state taxing authorities under applicable statutes of limitations is 2009. In July 2020, Minnesota began a review of the 2015 - 2018 Research and Experimentation Credits. As of Dec. 31, 2020, no material adjustments have been proposed.

Unrecognized Tax Benefits — Unrecognized tax benefit balance includes permanent tax positions, which if recognized would affect the annual ETR. In addition, the unrecognized tax benefit balance includes temporary tax positions for which the ultimate deductibility is highly certain, but for which there is uncertainty about the timing of such deductibility. A change in the period of deductibility would not affect the ETR but would accelerate the payment to the taxing authority to an earlier period.

Unrecognized tax benefits - permanent vs temporary:

(Millions of Dollars)	Dec. 31, 2020	Dec. 31, 2019
Unrecognized tax benefit — Permanent tax positions	$ 21	$ 15
Unrecognized tax benefit — Temporary tax positions	3	5
Total unrecognized tax benefit	$ 24	$ 20

Changes in unrecognized tax benefits:

(Millions of Dollars)	2020	2019	2018
Balance at Jan. 1	$ 20	$ 17	$ 18
Additions based on tax positions related to the current year	2	3	2
Reductions based on tax positions related to the current year	—	(1)	—
Additions for tax positions of prior years	16	1	—
Reductions for tax positions of prior years	(14)	—	(1)
Settlements with taxing authorities	—	—	(2)
Balance at Dec. 31	$ 24	$ 20	$ 17

Unrecognized tax benefits were reduced by tax benefits associated with NOL and tax credit carryforwards:

(Millions of Dollars)	Dec. 31, 2020	Dec. 31, 2019
NOL and tax credit carryforwards	$ (11)	$ (16)

Net deferred tax liability associated with the unrecognized tax benefit amounts and related NOLs and tax credits carryforwards were $8 million and $11 million at Dec. 31, 2020 and Dec. 31, 2019, respectively.

As the IRS audits resume and state review progresses, it is reasonably possible that the amount of unrecognized tax benefit could decrease up to approximately $15 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)	2020	2019	2018
Payable for interest related to unrecognized tax benefits at Jan. 1	$ (2)	$ (1)	$ (1)
Interest expense related to unrecognized tax benefits	—	(1)	—
Payable for interest related to unrecognized tax benefits at Dec. 31	$ (2)	$ (2)	$ (1)

No amounts were accrued for penalties related to unrecognized tax benefits as of Dec. 31, 2020, 2019 or 2018.

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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)	2020	2019
Federal tax credit carryforwards	$ 543	$ 449
State NOL carryforwards	151	133
Valuation allowances for state NOL carryforwards	(1)	(1)
State tax credit carryforwards, net of federal detriment [(a)]	71	78
Valuation allowances for state credit carryforwards, net of federal benefit [(b)]	(59)	(66)

(a) State tax credit carryforwards are net of federal detriment of $19 million and $21 million as of Dec. 31, 2020 and 2019, respectively.

(b) Valuation allowances for state tax credit carryforwards were net of federal benefit of $16 million and $18 million as of Dec. 31, 2020 and 2019, respectively.

Federal carryforward periods expire between 2031 and 2040 and state carryforward periods expire between 2021 and 2035.

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:

	2020	2019	2018
Federal statutory rate	21.0 %	21.0 %	21.0 %
State income tax on pretax income, net of federal tax effect	7.0	7.1	7.1
Increases (decreases) in tax from:			
Wind PTCs	(19.3)	(11.8)	(13.6)
Plant regulatory differences [(a)]	(7.2)	(7.4)	(8.8)
NOL Carryback	(2.1)	—	—
Other tax credits, net NOL & tax credit allowances	(1.2)	(1.5)	(1.1)
Change in unrecognized tax benefits	1.0	0.5	0.1
Other, net	(0.2)	0.1	0.5
Effective income tax rate	(1.0)%	8.0 %	5.2 %

(a) 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 credits are offset by corresponding revenue reductions.

Components of income tax expense for years ended Dec. 31:

(Millions of Dollars)	2020	2019	2018
Current federal tax expense (benefit)	$ 41	$ 80	$ (17)
Current state tax expense	12	8	5
Current change in unrecognized tax expense (benefit)	9	(1)	(1)
Deferred federal tax benefit	(102)	(86)	(3)
Deferred state tax expense	38	43	42
Deferred change in unrecognized tax (benefit) expense	(3)	4	2
Deferred ITCs	(1)	(1)	(1)
Total income tax (benefit) expense	$ (6)	$ 47	$ 27

Components of deferred income tax expense as of Dec. 31:

(Millions of Dollars)	2020	2019	2018
Deferred tax expense excluding items below	$ 61	$ 97	70
Amortization and adjustments to deferred income taxes on income tax regulatory assets and liabilities	(127)	(135)	(28)
Tax expense allocated to other comprehensive income, adoption of ASC Topic 326, adoption of ASU No. 2018-02 and other	(1)	(1)	(1)
Deferred tax (benefit) expense	$ (67)	$ (39)	$ 41

Components of the net deferred tax liability as of Dec. 31:

(Millions of Dollars)	2020	2019 [(a)]
Deferred tax liabilities:		
Differences between book and tax bases of property	$ 2,482	$ 2,361
Regulatory assets	270	255
Operating lease assets	147	170
Pension expense	72	68
Other	14	10
Total deferred tax liabilities	$ 2,985	$ 2,864
Deferred tax assets:		
Tax credit carryforward	$ 614	$ 527
Regulatory Liabilities	349	362
Operating lease liabilities	147	170
NOL and tax credit valuation allowances	(59)	(66)
Other employee benefits	38	38
NOL carryforward	12	10
Rate refund	7	11
Deferred ITCs	5	6
Other	32	27
Total deferred tax assets	$ 1,145	$ 1,085
Net deferred tax liability	$ 1,840	$ 1,779

(a) Prior periods have been reclassified to conform to current year presentation.

8. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

Accounting guidance for fair value measurements and disclosures provides a single definition of fair value and requires disclosures about assets and liabilities measured at fair value. A hierarchical framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value is established by this guidance.

- 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 highly liquid and actively traded instruments with quoted prices.
- Level 2 — Pricing inputs are other than quoted 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 are those valued with models requiring significant management judgment or estimation.

Cash equivalents — The fair values of cash equivalents are generally based on cost plus accrued interest; money market funds are measured using quoted NAV.

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 fund investments 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' investments may be redeemed with proper notice, however, 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 — The fair values of interest rate derivatives are based on broker quotes that utilize current market interest rate forecasts.

Commodity derivatives — The 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 contractual settlements relate to inactive delivery locations or extend to periods beyond those readily observable on active exchanges or quoted by brokers, the significance of the use of less observable forecasts of forward prices and volatilities 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 a 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 value of an FTR is derived from, and designed to offset, the cost 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 an FTR.

If forecasted costs of electric transmission congestion increase or decrease for a given FTR path, the value of that particular FTR instrument will likewise increase or decrease. Given the limited observability of certain inputs to the value of FTRs between auction processes, including expected plant operating schedules and retail and wholesale demand, fair value measurements for FTRs have been assigned a Level 3.

Non-trading monthly FTR settlements are included in fuel and purchased energy cost recovery mechanisms, and therefore changes in the fair value of the yet to be settled portions of most FTRs are deferred as a regulatory asset or liability. Given this regulatory treatment and the limited magnitude of NSP-Minnesota's FTRs relative to its electric utility operations, the numerous unobservable quantitative inputs pertinent to the value of FTRs are immaterial to the consolidated financial statements of NSP-Minnesota.

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 $981 million and $706 million as of Dec. 31, 2020 and 2019, respectively, and unrealized losses were $5 million and $6 million as of Dec. 31, 2020 and 2019, respectively.

Non-derivative instruments with recurring fair value measurements in the nuclear decommissioning fund:

	Dec. 31, 2020					
		Fair Value				
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	NAV	Total
Nuclear decommissioning fund [(a)]						
Cash equivalents	$ 40	$ 40	$ —	$ —	$ —	$ 40
Commingled funds	787	—	—	—	1,041	1,041
Debt securities	528	—	572	13	—	585
Equity securities	446	1,109	2	—	—	1,111
Total	$ 1,801	$ 1,149	$ 574	$ 13	$ 1,041	$ 2,777

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $53 million of rabbi trust assets and miscellaneous investments.

	Dec. 31, 2019					
		Fair Value				
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	NAV	Total
Nuclear decommissioning fund [(a)]						
Cash equivalents	$ 33	$ 33	$ —	$ —	$ —	$ 33
Commingled funds	733	—	—	—	935	935
Debt securities	489	—	495	13	—	508
Equity securities	485	962	2	—	—	964
Total	$ 1,740	$ 995	$ 497	$ 13	$ 935	$ 2,440

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $55 million of rabbi trust assets and miscellaneous investments.

For the years ended Dec. 31, 2020 and 2019, 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, 2020:

	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	$ 1	$ 116	$ 211	$ 257	$ 585

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Rabbi Trusts

NSP-Minnesota has established a rabbi trust to provide partial funding for future deferred compensation plan distributions.

Cost and fair value of assets held in rabbi trusts:

	Dec. 31, 2020				
		Fair Value			
(Millions of Dollars)	**Cost**	**Level 1**	**Level 2**	**Level 3**	**Total**
Rabbi Trusts [(a)]					
Cash equivalents	$ 1	$ 1	$ —	$ —	$ 1
Mutual funds	14	16	—	—	16
Total	$ 15	$ 17	$ —	$ —	$ 17

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet.

	Dec. 31, 2019				
		Fair Value			
(Millions of Dollars)	**Cost**	**Level 1**	**Level 2**	**Level 3**	**Total**
Rabbi Trusts [(a)]					
Cash equivalents	$ 1	$ 1	$ —	$ —	$ 1
Mutual funds	11	13	—	—	13
Total	$ 12	$ 14	$ —	$ —	$ 14

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet.

Derivative Instruments 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, utility commodity prices and vehicle fuel prices.

Interest Rate Derivatives — NSP-Minnesota enters into various instruments that effectively fix the yield or price on a specified benchmark interest rate for an anticipated debt issuance for a specific period. These derivative instruments are generally designated as cash flow hedges for accounting purposes, with changes in fair value prior to settlement recorded as other comprehensive income.

At Dec. 31, 2020, 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 related hedged interest rate transactions impact earnings.

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 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 activities governed by this policy.

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, as well as for trading purposes. This could include the purchase or sale of energy or energy-related products, natural gas to generate electric energy, natural gas for resale, FTRs, vehicle fuel, and weather derivatives.

As of Dec. 31, 2020, NSP-Minnesota had no commodity contracts designated as cash flow hedges. NSP-Minnesota may enter into derivative instruments that mitigate commodity price risk on behalf of electric and natural gas customers, but may not be designated as qualifying hedging transactions. The classification as a regulatory asset or liability, if applicable, is based on approved regulatory recovery mechanisms.

NSP-Minnesota enters into commodity derivative instruments for trading purposes not directly related to commodity price risks associated with serving its electric and natural gas customers. Changes in the fair value of these commodity derivatives are recorded in electric operating revenues, net of amounts credited to customers under margin-sharing mechanisms.

Gross notional amounts of commodity forwards, options and FTRs:

(Amounts in Millions) [(a) (b)]	**Dec. 31, 2020**	**Dec. 31, 2019**
MWh of electricity	65	79
MMBtu of natural gas	83	78

(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, 2020, six of NSP-Minnesota's 10 most significant counterparties for these activities, comprising $31 million or 59% of this credit exposure, had investment grade credit ratings from S&P, Moody's or Fitch Ratings. Four of the 10 most significant counterparties, comprising $13 million or 25% of this credit exposure, were not rated by these external agencies, but based on NSP-Minnesota's internal analysis, had credit quality consistent with investment grade. Seven of these significant counterparties are municipal or cooperative electric entities, RTOs or other utilities.

Qualifying Cash Flow Hedges — Financial impact of qualifying interest rate and vehicle fuel 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:

(Millions of Dollars)	**2020**	**2019**	**2018**
Accumulated other comprehensive loss related to cash flow hedges at Jan. 1	$ (20)	$ (20)	$ (21)
After-tax net realized losses on derivative transactions reclassified into earnings	1	—	1
Accumulated other comprehensive loss related to cash flow hedges at Dec. 31	$ (19)	$ (20)	$ (20)

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Impact of derivative activity:

(Millions of Dollars)	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in: Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities
Year Ended Dec. 31, 2020		
Other derivative instruments		
Electric commodity	$ —	$ 2
Natural gas commodity	—	(2)
Total	$ —	$ —
Year Ended Dec. 31, 2019		
Other derivative instruments		
Electric commodity	$ —	$ 2
Natural gas commodity	—	(3)
Total	$ —	$ (1)
Year Ended Dec. 31, 2018		
Other derivative instruments		
Electric commodity	$ —	$ (6)
Natural gas commodity	—	2
Total	$ —	$ (4)

(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, 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]
Total	$ —	$ (1)	$ (9)

(a) Recorded to interest charges.

(b) Recorded to electric operating revenues. Portions of these gains and losses are subject to sharing with electric customers through margin-sharing mechanisms and deducted from gross revenue, as appropriate.

(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.

(d) Amounts are recorded to cost of natural gas sold and transported. These derivative settlement gains and losses are shared with natural gas customers through purchased natural gas cost-recovery mechanisms, and reclassified out of income as regulatory assets and liabilities, as appropriate.

(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, 2019			
Other derivative instruments			
Commodity trading	$ —	$ —	$ —
Electric commodity	—	1 [a]	—
Natural gas commodity	—	1 [b]	(3) [b]
Total	$ —	$ 2	$ (3)

(a) 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.

(b) Amounts are recorded to cost of natural gas sold and transported. These derivative settlement gains and losses are shared with natural gas customers through purchased natural gas cost-recovery mechanisms, and reclassified out of income as regulatory assets and liabilities, as appropriate.

(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, 2018			
Derivatives designated as cash flow hedges			
Interest rate	$ 1 [a]	$ —	$ —
Total	$ 1	$ —	$ —
Other derivative instruments			
Commodity trading	$ —	$ —	$ 11 [b]
Electric commodity	—	3 [c]	—
Natural gas commodity	—	(2) [d]	(1) [d]
Total	$ —	$ 1	$ 10

(a) Recorded to interest charges.

(b) Recorded to electric operating revenues. Portions of these gains and losses are subject to sharing with electric customers through margin-sharing mechanisms and deducted from gross revenue, as appropriate.

(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.

(d) Amounts are recorded to cost of natural gas sold and transported. These derivative settlement gains and losses are shared with natural gas customers through purchased natural gas cost-recovery mechanisms, and reclassified out of income as regulatory assets and liabilities, as appropriate.

NSP-Minnesota had no derivative instruments designated as fair value hedges during the years ended Dec. 31, 2020, 2019 and 2018.

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Credit Related Contingent Features — Contract provisions for derivative instruments that NSP-Minnesota enters into, including those accounted for as normal purchase-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 NSP-Minnesota's credit ratings are downgraded below its investment grade credit rating by any of the major credit rating agencies. As of Dec. 31, 2020 and 2019, there were $4 million and $7 million derivative instruments in a liability position 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 the other financing arrangements related to payment terms or other covenants. As of Dec. 31, 2020, there were approximately $14 million of derivative instruments in a liability position with such underlying contract provisions.

Provisions allow counterparties to seek performance assurance, including cash collateral, in the event that NSP-Minnesota's ability to fulfill its contractual obligations is reasonably expected to be impaired. NSP-Minnesota had no collateral posted related to adequate assurance clauses in derivative contracts as of Dec. 31, 2020 and 2019.

Recurring Fair Value Measurements — NSP-Minnesota's derivative assets and liabilities measured at fair value on a recurring basis were as follows:

	Dec. 31, 2020						Dec. 31, 2019					
	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	$ 1	$ 26	$ —	$ 27	$ (25)	$ 2	$ 2	$ 40	$ 23	$ 65	$ (42)	$ 23
Electric commodity	—	—	13	13	(1)	12	—	—	9	9	(1)	8
Natural gas commodity	—	3	—	3	—	3	—	1	—	1	—	1
Total current derivative assets	$ 1	$ 29	$ 13	$ 43	$ (26)	17	$ 2	$ 41	$ 32	$ 75	$ (43)	32
Noncurrent derivative assets												
Other derivative instruments:												
Commodity trading	$ 7	$ 39	$ —	$ 46	$ (41)	$ 5	$ 9	$ 29	$ 6	$ 44	$ (35)	$ 9
Total noncurrent derivative assets	$ 7	$ 39	$ —	$ 46	$ (41)	5	$ 9	$ 29	$ 6	$ 44	$ (35)	9

	Dec. 31, 2020						Dec. 31, 2019					
	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	$ 3	$ 18	$ 10	$ 31	$ (25)	$ 6	$ 2	$ 42	$ 15	$ 59	$ (50)	$ 9
Electric commodity	—	—	1	1	(1)	—	—	—	1	1	(1)	—
Natural gas commodity	—	2	—	2	—	2	—	2	—	2	—	2
Total current derivative liabilities	$ 3	$ 20	$ 11	$ 34	$ (26)	8	$ 2	$ 44	$ 16	$ 62	$ (51)	11
PPAs [(b)]						14						14
Current derivative instruments						$ 22						$ 25
Noncurrent derivative liabilities												
Other derivative instruments:												
Commodity trading	$ 2	$ 35	$ 13	$ 50	$ (27)	$ 23	$ 2	$ 32	$ 17	$ 51	$ (3)	$ 48
Total noncurrent derivative liabilities	$ 2	$ 35	$ 13	$ 50	$ (27)	23	$ 2	$ 32	$ 17	$ 51	$ (3)	48
PPAs [(b)]						48						62
Noncurrent derivative instruments						$ 71						$ 110

(a) NSP-Minnesota nets derivative instruments and related collateral on its consolidated balance sheets when supported by a legally enforceable master netting agreement, and all derivative instruments and related collateral amounts were subject to master netting agreements at Dec. 31, 2020 and 2019. At both Dec. 31, 2020 and 2019, derivative assets and liabilities include $15 million and $32 million of obligations to return cash collateral, respectively. At Dec. 31, 2020 and 2019, derivative assets and liabilities include the rights to reclaim cash collateral of $1 million and $8 million, respectively. The counterparty netting excludes settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

(b) During 2006, Xcel Energy qualified these contracts under the normal purchase exception. Based on this qualification, the contracts are no longer adjusted to fair value and the previous carrying value of these contracts will be amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.

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Changes in Level 3 commodity derivatives for the years ended Dec. 31, 2020, 2019 and 2018:

	Year Ended Dec. 31		
(Millions of Dollars)	**2020**	**2019**	**2018**
Balance at Jan. 1	$ 5	$ 14	$ 23
Purchases	28	17	26
Settlements	(49)	(28)	(17)
Net transactions recorded during the period:			
(Losses) gains recognized in earnings [(a)]	(8)	3	(2)
Net gains (losses) recognized as regulatory assets and liabilities	13	(1)	(16)
Balance at Dec. 31	$ (11)	$ 5	$ 14

[(a)] Level 3 losses and gains recognized in earnings are subject to offsetting gains and losses of derivative instruments categorized as levels 1 and 2 in the income statement.

NSP-Minnesota recognizes transfers between levels as of the beginning of each period. There were no transfers of amounts between levels for derivative instruments for the years ended Dec. 31, 2020, 2019 and 2018.

Fair Value of Long-Term Debt

As of Dec. 31, other financial instruments for which the carrying amount did not equal fair value:

	2020		2019	
(Millions of Dollars)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Long-term debt, including current portion	$ 5,904	$ 7,391	$ 5,521	$ 6,297

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, 2020 and 2019, 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 1.78, 2.74 and 3.57 percent in 2020, 2019, and 2018, 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, 2020 and 2019 were $43 million and $39 million, respectively, of which $4 million was attributable to NSP-Minnesota in both years. In 2020 and 2019, Xcel Energy recognized net benefit cost for the SERP and nonqualified plans of $6 million and $4 million, respectively, of which $1 million was attributable to NSP-Minnesota in both years.

Xcel Energy, which includes NSP-Minnesota, bases the investment-return assumption on expected long-term performance for each of the asset classes in its pension and postretirement health care portfolios. For pension assets, Xcel Energy considers the historical returns achieved by its asset portfolio over the past 20 years or longer period, as well as the long-term projected return levels. 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 2020 were above the assumed level of 7.10%.
- Investment returns in 2019 were above the assumed level of 7.10%.
- Investment returns in 2018 were below the assumed level of 7.10%.
- In 2021, NSP-Minnesota's expected investment-return assumption is 6.60%.

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 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.

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Plan Assets

For each of the fair value hierarchy levels, NSP-Minnesota's pension plan assets measured at fair value:

	Dec. 31, 2020 [(a)]					Dec. 31, 2019 [(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	$ 52	$ —	$ —	$ —	$ 52	$ 41	$ —	$ —	$ —	$ 41
Commingled funds	369	—	—	284	653	360	—	—	270	630
Debt securities	—	167	1	—	168	—	156	1	—	157
Equity securities	20	—	—	—	20	23	—	—	—	23
Other	3	1	—	—	4	(32)	1	—	(5)	(36)
Total	$ 444	$ 168	$ 1	$ 284	$ 897	$ 392	$ 157	$ 1	$ 265	$ 815

(a) See Note 8 for further information on 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, 2020 [(a)]					Dec. 31, 2019 [(a)]				
(Millions of Dollars)	**Level 1**	**Level 2**	**Level 3**	**Measured at NAV**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Measured at NAV**	**Total**
Commingled funds	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 1	$ 1
Debt securities	—	2	—	—	2	—	2	—	—	2
Total	$ —	$ 2	$ —	$ —	$ 2	$ —	$ 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 2020. Immaterial assets were transferred in or out of Level 3 for 2019.

Funded Status — Benefit obligations for both pension and postretirement plans increased from Dec. 31, 2019 to Dec. 31, 2020, due primarily to decreases 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)	**2020**	**2019**	**2020**	**2019**
Change in Benefit Obligation:				
Obligation at Jan. 1	$ 942	$ 907	$ 76	$ 76
Service cost	27	25	—	—
Interest cost	31	37	2	3
Plan amendments	—	1	—	—
Actuarial loss	84	62	2	4
Benefit payments	(95)	(90)	(7)	(7)
Obligation at Dec. 31	$ 989	$ 942	$ 73	$ 76
Change in Fair Value of Plan Assets:				
Fair value of plan assets at Jan. 1	$ 815	$ 711	$ 3	$ 2
Actual return on plan assets	133	147	—	—
Employer contributions	44	47	6	8
Benefit payments	(95)	(90)	(7)	(7)
Fair value of plan assets at Dec. 31	$ 897	$ 815	$ 2	$ 3
Funded status of plans at Dec. 31	$ (92)	$ (127)	$ (71)	$ (73)
Amounts recognized in the Consolidated Balance Sheet at Dec. 31:				
Current liabilities	$ —	$ —	$ (5)	$ (4)
Noncurrent liabilities	(92)	(127)	(66)	(69)
Net amounts recognized	$ (92)	$ (127)	$ (71)	$ (73)

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Significant Assumptions Used to Measure Benefit Obligations:	Pension Benefits 2020	Pension Benefits 2019	Postretirement Benefits 2020	Postretirement Benefits 2019
Discount rate for year-end valuation	2.71 %	3.49 %	2.65 %	3.47 %
Expected average long-term increase in compensation level	3.75 %	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	5.50 %	6.00 %
Health care costs trend rate — initial: Post-65	N/A	N/A	5.00 %	5.10 %
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	5	3

The accumulated benefit obligation for the pension plan was $912 million and $872 million as of Dec. 31, 2020 and 2019, respectively.

Net Periodic Benefit Cost (Credit) — Net periodic benefit cost (credit), other than the service cost component, is included in other income 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:

(Millions of Dollars)	Pension Benefits 2020	Pension Benefits 2019	Pension Benefits 2018	Postretirement Benefits 2020	Postretirement Benefits 2019	Postretirement Benefits 2018
Service cost	$ 27	$ 25	$ 28	$ —	$ —	$ —
Interest cost	31	37	35	2	3	3
Expected return on plan assets	(55)	(54)	(58)	—	—	—
Amortization of prior service cost	—	—	—	(3)	(3)	(3)
Amortization of net loss	33	30	38	1	2	2
Settlement charge [(a)]	—	—	49	—	—	—
Net periodic pension cost	36	38	92	—	2	2
Effects of regulation	(4)	(5)	(66)	—	—	—
Net benefit cost recognized for financial reporting	$ 32	$ 33	$ 26	$ —	$ 2	$ 2
Significant Assumptions Used to Measure Costs:						
Discount rate	3.49 %	4.31 %	3.63 %	3.47 %	4.32 %	3.62 %
Expected average long-term increase in compensation level	3.75	3.75	3.75	—	—	—
Expected average long-term rate of return on assets	7.10	7.10	7.10	4.50	4.50	5.30

(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 2018, as a result of lump-sum distributions during the 2018 plan year, NSP-Minnesota recorded a total pension settlement charge of $49 million in 2018, which was not recognized due to the effects of regulation. There were no settlement charges recorded to the qualified pension plans in 2020 and 2019.

(Millions of Dollars)	Pension Benefits 2020	Pension Benefits 2019	Postretirement Benefits 2020	Postretirement Benefits 2019
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:				
Net loss	$ 414	$ 440	$ 37	$ 37
Prior service credit	—	—	(6)	(9)
Total	$ 414	$ 440	$ 31	$ 28
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	$ 29	$ 29	$ —	$ —
Noncurrent regulatory assets	385	411	29	26
Deferred income taxes	—	—	1	1
Net-of-tax accumulated other comprehensive income	—	—	1	1
Total	$ 414	$ 440	$ 31	$ 28
Measurement date	Dec 31, 2020	Dec 31, 2019	Dec 31, 2020	Dec 31, 2019

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 2018 – 2021 to meet minimum funding requirements.

Total voluntary and required pension funding contributions across all four of Xcel Energy's pension plans were as follows:

- $125 million in January 2021, of which $33 million is attributable to NSP-Minnesota.
- $150 million in 2020, of which $44 million was attributable to NSP-Minnesota.
- $154 million in 2019, of which $47 million was attributable to NSP-Minnesota.
- $150 million in 2018, of which $63 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:

- $10 million in 2021, of which $7 million is attributable to NSP-Minnesota.
- $11 million in 2020, of which $6 million, was attributable to NSP-Minnesota.
- $15 million in 2019, of which $8 million was attributable to NSP-Minnesota.
- $11 million in 2018, of which $3 million was attributable to NSP-Minnesota.

Target asset allocations:

	Pension Benefits		Postretirement Benefits	
	2020	2019	2020	2019
Domestic and international equity securities	35 %	37 %	15 %	15 %
Long-duration fixed income and interest rate swap securities	35	30	—	—
Short-to-intermediate fixed income securities	13	14	72	72
Alternative investments	15	17	9	9
Cash	2	2	4	4
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 2019, the Pension Protection Act measurement concept was extended beyond 2019 for NSP bargaining terminations and retirements to Dec. 31, 2022.

In 2020 and 2018, there were no significant plan amendments made which affected the postretirement benefit obligation.

Projected Benefit Payments

NSP-Minnesota's projected benefit payments:

(Millions of Dollars)	Projected Pension Benefit Payments	Gross Projected Postretirement Health Care Benefit Payments	Expected Medicare Part D Subsidies	Net Projected Postretirement Health Care Benefit Payments
2021	$ 104	$ 7	$ —	$ 7
2022	92	6	—	6
2023	86	6	—	6
2024	79	5	—	5
2025	75	5	—	5
2026-2030	320	21	—	21

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 $12 million in 2020, 2019 and 2018.

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 of such matters, including a possible eventual loss. For current proceedings not specifically reported, management does not anticipate that the ultimate liabilities, if any, would have a material effect on NSP-Minnesota's financial statements. Unless otherwise required by GAAP, legal fees are expensed as incurred.

Rate Matters and Other

Sherco — In 2018, NSP-Minnesota and SMMPA (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 FCA.

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In March 2019, the MPUC approved NSP-Minnesota's 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 accordance with a prior MPUC order, NSP-Minnesota made a compliance filing in August 2020 detailing all costs that resulted from the outage and all insurance recoveries received by NSP-Minnesota in connection with the outage.

In January 2021, the Minnesota Office of the Attorney General and DOC filed comments recommending that NSP-Minnesota refund approximately $17 million of replacement power costs previously recovered through the FCA. On Jan. 27, 2021, NSP-Minnesota 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 pending. A loss related to this matter is deemed remote.

Westmoreland Arbitration — In November 2014, insurers for Westmoreland Coal Company filed an arbitration demand against NSP-Minnesota, SMMPA and Western Fuels Association, seeking recovery of alleged business losses due to a turbine failure at Sherco Unit 3. The Westmoreland insurers claim NSP-Minnesota's invocation of the force majeure clause to stop the supply of coal was improper because the incident was allegedly caused by NSP-Minnesota's failure to conform to industry maintenance standards. Westmoreland's insurers quantified their losses as approximately $36 million.

Arbitration was delayed pending resolution of a separate lawsuit brought by NSP-Minnesota, SMMPA, and their insurers against various GE entities based on the inspection and maintenance advice GE provided for Sherco Unit 3. In July 2020, following the conclusion of the appeal that fully resolved the GE litigation, Westmoreland's insurers served notice, which triggered the arbitration to resume.

NSP-Minnesota denies the claims asserted by the Westmoreland insurers and believes it properly stopped the supply of coal based upon the force majeure provision. It is uncertain when a final resolution will occur, but it is unlikely an arbitration hearing will take place before the fourth quarter 2021. At this stage of the proceeding, before any discovery has been conducted/completed, a reasonable estimate of damages or range of damages cannot be determined.

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%.

In September 2016, the FERC issued an order (Opinion No. 551) granting a 10.32% base ROE effective for the first complaint period of Nov. 12, 2013 to Feb. 11, 2015 and subsequent to the date of the order. The D.C Circuit subsequently vacated and remanded the FERC Opinion.

In November 2019, the FERC issued an order (Opinion No. 569), which set the MISO base ROE at 9.88%, effective Sept. 28, 2016 and for the first complaint period. The FERC also dismissed the second complaint. In December 2019, MISO TOs filed a request for rehearing regarding the new ROE methodology announced in Opinion No. 569. Customers also filed requests for rehearing claiming, among other points, that the FERC erred by dismissing the second complaint without refunds.

In May 2020, the FERC issued an order (Opinion No. 569-A) which granted rehearing in part to Opinion 569 and further refined the FERC's ROE methodology, most significantly to incorporate the risk premium model (in addition to the discounted cash flow and capital asset pricing models), resulting in a new base ROE of 10.02%, effective Sept. 28, 2016 and for the first complaint period. The FERC also affirmed its decision in Opinion No. 569 to dismiss the second complaint.

In June 2020, various parties filed requests for rehearing of Opinion 569-A with the FERC. In November 2020, the FERC issued an order (Opinion No. 569-B) in response to the rehearing requests. The FERC corrected certain inputs to its ROE calculation model, did not change the ROE for the first MISO complaint period and upheld its decision to deny refunds for the second complaint period. Each 10 basis point reduction in the allowed base ROE for the first complaint and second complaint would reduce net income by $2 million and $1 million, respectively.

Various parties have filed petitions for review of Opinion Nos. 569, 569-A and 569-B at the D.C. Circuit. These appeals remain pending.

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 released to the environment. NSP-Minnesota may sometimes pay all 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.

MGP, Landfill and Disposal Sites

NSP-Minnesota is currently investigating, remediating or performing post closure actions at seven MGP, landfill or other disposal sites across its service territories. NSP-Minnesota has recognized its best estimate of costs/liabilities that will result from final resolution of these issues, however, the outcome and timing is 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.

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NSP-Minnesota is conducting groundwater sampling and monitoring implementing assessment of corrective measures at certain CCR landfills and surface impoundments. No results above the groundwater protection standards in the rule were identified. Until NSP-Minnesota completes its assessment, it is uncertain what impact, if any, there will be on the operations, financial condition or cash flows.

In August 2020, the EPA published its final rule to implement a cease receipt and initiate a closure date of April 2021 for all CCR impoundments affected by the August 2018 D.C. Circuit ruling. The D.C. Circuit concluded that the EPA cannot allow utilities to continue to use unlined impoundments (including clay lined impoundments) for the storage or disposal of coal ash. This final rule required NSP-Minnesota to expedite closure plans for one impoundment.

In October 2020, NSP-Minnesota completed construction of a new impoundment to replace the clay lined impoundment at a cost of $9 million. With the new ash pond in service, NSP-Minnesota has initiated closure activities for the existing ash pond at an estimated cost of $4 million. NSP-Minnesota has five years to complete closure activities.

Closure costs for existing impoundments are included in the calculation of the ARO.

Federal CWA WOTUS Rule — In April 2020, the EPA and U.S. Army Corps of Engineers (“Agencies”) replaced the 2015 WOTUS rule and narrowed the definition of WOTUS (“2020 WOTUS Rule”). The new definition simplifies the process whether waters are subject to CWA jurisdiction and streamlines the permitting process. NSP-Minnesota does not anticipate that compliance costs will be material.

Federal CWA ELG — In 2015, the EPA issued a final ELG rule for power plants that discharge treated effluent to surface waters as well as utility-owned landfills that receive CCRs. In October 2020, the EPA published a final rule revising the regulations.

The retirement of units affected by the final ELG rule is subject to regulatory approval. The exact total cost of ELG compliance is therefore uncertain but NSP-Minnesota does not anticipate that compliance costs will be material.

Federal CWA Section 316(b) — The federal CWA requires the EPA to regulate cooling water intake structures to assure that these structures reflect the best technology available for minimizing impingement and entrainment of aquatic species. NSP-Minnesota estimates the likely cost for complying with impingement and entrainment requirements is approximately $37 million, to be incurred between 2021 and 2028. NSP-Minnesota believes six plants could be required to make improvements to reduce impingement and entrainment. The exact total cost of the impingement and entrainment improvements is uncertain, but could be up to $189 million. NSP-Minnesota anticipates these costs will be fully recoverable through regulatory mechanisms.

Environmental Requirements — Air

Regional Haze Rules — The regional haze program requires sulfur dioxide, nitrogen oxide and particulate matter emission controls at power plants to reduce visibility impairment in national parks and wilderness areas. The program includes best available retrofit technology and reasonable further progress. The regional haze first planning period requirements were approved by the EPA and implemented by 2014.

All states are now subject to a second round of regional haze planning/ rulemaking, focusing on additional reductions to meet reasonable progress requirements. Any additional impacts to NSP-Minnesota facilities are expected to be minimal.

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 $2.8 billion and $2.4 billion for 2020 and 2019, respectively.

NSP-Minnesota’s AROs were as follows:

	2020					
(Millions of Dollars)	**Jan. 1, 2020**	**Amounts Incurred** (a)	**Amounts Settled** (b)	**Accretion**	**Cash Flow Revisions** (c)	**Dec. 31, 2020**
Electric						
Nuclear	$2,068	$ —	$ —	$ 105	$ (216)	$ 1,957
Wind	113	90	—	7	60	270
Steam and other production	47	—	(3)	2	21	67
Distribution	15	—	—	1	—	16
Natural gas						
Transmission and distribution	36	—	—	2	1	39
Common						
Miscellaneous	1	—	—	—	—	1
Total liability	$2,280	$ 90	$ (3)	$ 117	$ (134)	$ 2,350

(a) Amounts incurred relate to the wind farms placed in service in 2020 (Blazing Star 1, Crowned Ridge, Jeffers and Community Wind North).

(b) Amounts settled related to closure of certain ash containment facilities.

(c) In 2020, AROs were revised for changes in timing and estimates of cash flows. Revisions in the nuclear AROs were driven by reductions in spent fuel cooling time requirements in the nuclear triennial filing coupled with decreasing interest rates. Changes in wind AROs were driven by new dismantling studies. Revisions in steam and other production AROs primarily related to changes in cost estimates for remediation of ash containment facilities.

	2019					
(Millions of Dollars)	**Jan. 1, 2019**	**Amounts Incurred** (a)	**Amounts Settled** (b)	**Accretion**	**Cash Flow Revisions** (c)	**Dec. 31, 2019**
Electric						
Nuclear	$1,968	$ —	$ —	$ 100	$ —	$ 2,068
Wind	105	10	—	5	(7)	113
Steam and other production	49	—	(3)	2	(1)	47
Distribution	14	—	—	1	—	15
Miscellaneous	2	—	—	—	(2)	—
Natural gas						
Transmission and distribution	38	—	—	2	(4)	36
Common						
Miscellaneous	1	—	—	—	—	1
Total liability	$2,177	$ 10	$ (3)	$ 110	$ (14)	$ 2,280

(a) Amounts incurred relate to the wind farms placed in service in 2019 (Lake Benton and Foxtail).

(b) Amounts settled related to closure of certain ash containment facilities.

(c) In 2019, AROs were revised for changes in timing and estimates of cash flows. Changes in wind AROs were driven by new dismantling studies. Changes in gas transmission and distribution AROs were primarily related to increased gas line mileage and number of services, which were more than offset by decreased inflation rates. Changes in steam and other production AROs primarily related to the cost estimates to remediate ponds at production facilities.

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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, 2020. 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 $13.8 billion under the Price-Anderson amendment to the Atomic Energy Act. NSP-Minnesota has secured $450 million of coverage for its public liability exposure with a pool of insurance companies. The remaining $13.3 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 $21 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 $11 million for business interruption insurance and $34 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 47 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.

Regulatory Plant Decommissioning Recovery — Decommissioning activities for NSP-Minnesota's nuclear facilities are planned to begin at the end of each unit's operating license and be completed by 2095. 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.

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.

Obligations for decommissioning are expected to be funded 100% by the external decommissioning trust fund. The cost study assumes the external decommissioning fund will earn an after-tax return between 5.23% and 6.30%. Realized and unrealized gains on fund investments are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs. Decommissioning costs are quantified in 2014 dollars. Escalation rates are 4.36% for plant removal activities and 3.36% for fuel management and site restoration activities.

NSP-Minnesota had $2.8 billion of assets held in external decommissioning trusts at Dec. 31, 2020. The following table summarizes the funded status of NSP-Minnesota's decommissioning obligation. Xcel Energy believes future decommissioning costs will continue to be recovered in customer rates. The following amounts were prepared on a regulatory basis and not directly recorded in the financial statements as an ARO.

	Regulatory Basis	
(Millions of Dollars)	**2020**	**2019**
Estimated decommissioning cost obligation from most recently approved study (in 2014 dollars)	$ 3,012	$ 3,012
Effect of escalating costs	844	688
Estimated decommissioning cost obligation (in current dollars)	3,856	3,700
Effect of escalating costs to payment date	7,349	7,505
Estimated future decommissioning costs (undiscounted)	11,205	11,205
Effect of discounting obligation (using average risk-free interest rate of 1.64% and 2.39% for 2020 and 2019, respectively)	(4,181)	(5,562)
Discounted decommissioning cost obligation	$ 7,024	$ 5,643
Assets held in external decommissioning trust	$ 2,777	$ 2,440
Underfunding of external decommissioning fund compared to the discounted decommissioning obligation	4,247	3,203

Calculations and data used by the regulator in approving NSP-Minnesota's rates are useful in assessing future cash flows. Regulatory basis information is a means to reconcile amounts previously provided to the MPUC and utilized for regulatory purposes to amounts used for financial reporting.

Reconciliation of the discounted decommissioning cost obligation - regulated basis to the ARO recorded in accordance with GAAP:

(Millions of Dollars)	**2020**	**2019**
Discounted decommissioning cost obligation - regulated basis	$ 7,024	$ 5,643
Differences in discount rate and market risk premium	(2,628)	(2,295)
O&M costs not included for GAAP	(1,734)	(1,280)
ARO differences between 2020 and 2014 cost studies	(705)	—
Nuclear production decommissioning ARO - GAAP	$ 1,957	$ 2,068

Decommissioning expenses recognized as a result of regulation:

(Millions of Dollars)	**2020**	**2019**	**2018**
Annual decommissioning recorded as depreciation expense: [(a) (b)]	$ 20	$ 20	$ 20

(a) Decommissioning expense does not include depreciation of the capitalized nuclear asset retirement costs.

(b) Decommissioning expenses in 2020, 2019 and 2018 include Minnesota's retail jurisdiction annual funding requirement of approximately $14 million.

The 2014 nuclear decommissioning filing, approved in 2015, was used for regulatory presentation in 2020, 2019 and 2018. Although there was a nuclear triennial filing in 2017, the MPUC continued to approve the 2014 triennial filing as the regulatory basis in 2020, 2019 and 2018. In December 2020, the MPUC verbally approved NSP-Minnesota to continue using the 2014 filing as the basis for 2021.

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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 are 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, 2020	Dec. 31, 2019
PPAs	$ 558	$ 556
Other	74	72
Gross operating lease ROU assets	632	628
Accumulated amortization	(144)	(64)
Net operating lease ROU assets	$ 488	$ 564

Components of lease expense:

(Millions of Dollars)	2020	2019	2018
Operating leases			
PPA capacity payments	$ 89	$ 76	$ 63
Other operating leases [(a)]	8	9	14
Total operating lease expense [(b)]	$ 97	$ 85	$ 77

(a) Includes short-term lease expense of $2 million, $1 million and $2 million for 2020, 2019 and 2018, 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, 2020:

(Millions of Dollars)	PPA [(a) (b)] Operating Leases	Other Operating Leases	Total Operating Leases
2021	$ 95	$ 8	$ 103
2022	96	12	108
2023	98	8	106
2024	100	7	107
2025	80	7	87
Thereafter	40	39	79
Total minimum obligation	509	81	590
Interest component of obligation	(48)	(14)	(62)
Present value of minimum obligation	$ 461	$ 67	528
Less current portion			(85)
Noncurrent operating lease liabilities			$ 443
Weighted-average remaining lease term in years			5.8

(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 with various expiration dates through 2033 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 contain minimum energy purchase commitments, and total energy payments on those contracts were $112 million, $102 million and $105 million in 2020, 2019 and 2018, respectively.

Included in electric fuel and purchased power expenses for PPAs accounted for as executory contracts were payments for capacity of $52 million, $54 million and $53 million in 2020, 2019 and 2018, 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, 2020, 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)]
2021	$ 56	$ 156
2022	60	172
2023	61	176
2024	63	181
2025	26	60
Thereafter	19	85
Total [(b)]	$ 285	$ 830

(a) Excludes contingent energy payments for renewable energy PPAs.

(b) Includes amounts allocated to NSP-Wisconsin through intercompany charges.

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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 2021 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, 2020:

(Millions of Dollars)	Coal	Nuclear fuel	Natural gas supply	Natural gas storage and transportation
2021	$ 79	$ 101	$ 58	$ 124
2022	69	87	1	120
2023	35	103	1	109
2024	1	83	—	103
2025	1	121	—	93
Thereafter	2	274	—	200
Total [(a)]	$ 187	$ 769	$ 60	$ 749

(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 1,347 MW of capacity under long-term PPAs at both Dec. 31, 2020 and 2019 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:

	2020		
(Millions of Dollars)	Gains and Losses on Cash Flow Hedges	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive loss at Jan. 1	$ (20)	$ (3)	$ (23)
Losses reclassified from net accumulated other comprehensive loss:			
Interest rate derivatives, net of tax of $—	1 [(a)]	—	1
Net current period other comprehensive income	1	—	1
Accumulated other comprehensive loss at Dec. 31	$ (19)	$ (3)	$ (22)

(a) Included in interest charges.

	2019		
(Millions of Dollars)	Losses on Cash Flow Hedges	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive loss at Jan. 1	$ (20)	$ (3)	$ (23)
Accumulated other comprehensive loss at Dec. 31	$ (20)	$ (3)	$ (23)

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 electricity which is transmitted and distributed 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 NSP-Minnesota's wholesale commodity and trading operations.
- **Regulated Natural Gas** — The regulated natural gas utility segment transports, stores and distributes natural gas 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 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.

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NSP-Minnesota's segment information is as follows:

(Millions of Dollars)	2020	2019	2018
Regulated Electric			
Operating revenues - external [(a)]	$ 4,571	$ 4,506	$ 4,508
Intersegment revenue	1	1	1
Total revenues	$ 4,572	$ 4,507	$ 4,509
Depreciation and amortization	773	742	698
Interest charges and financing costs	221	205	199
Income tax (benefit) expense	(14)	36	16
Net income	553	491	450
Regulated Natural Gas			
Operating revenues - external	$ 493	$ 571	$ 583
Intersegment revenue	—	1	—
Total revenues	$ 493	$ 572	$ 583
Depreciation and amortization	51	49	43
Interest charges and financing costs	17	16	15
Income tax expense	7	12	10
Net income	30	40	34
All Other			
Total revenues	$ 37	$ 35	$ 31
Depreciation and amortization	1	—	1
Income tax expense (benefit)	1	(1)	1
Net income	8	12	8
Consolidated Total			
Total revenues [(a)]	$ 5,102	$ 5,114	$ 5,123
Reconciling eliminations	(1)	(2)	(1)
Total operating revenues	$ 5,101	$ 5,112	$ 5,122
Depreciation and amortization	825	791	742
Interest charges and financing costs	238	221	214
Income tax (benefit) expense	(6)	47	27
Net income	591	543	492

(a) Operating revenues include $440 million, $457 million and $474 million of intercompany electric revenue for the years ended Dec. 31, 2020, 2019 and 2018, 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)	2020	2019	2018
Operating revenues:			
Electric	$ 440	$ 457	$ 474
Gas	1	1	—
Operating expenses:			
Purchased power	59	61	61
Transmission expense	109	116	97
Other operating expenses — paid to Xcel Energy Services Inc.	584	533	535
Interest expense	—	1	—

Accounts receivable and payable with affiliates at Dec. 31 were:

	2020		2019	
(Millions of Dollars)	Accounts Receivable	Accounts Payable	Accounts Receivable	Accounts Payable
NSP-Wisconsin	$ 6	$ —	$ 8	$ —
PSCo	1	—	—	19
SPS	—	3	—	4
Other subsidiaries of Xcel Energy Inc.	25	63	36	53
	$ 32	$ 66	$ 44	$ 76

14. Summarized Quarterly Financial Data (Unaudited)

	Quarter Ended			
(Millions of Dollars)	March 31, 2020	June 30, 2020	Sept. 30, 2020	Dec. 31, 2020
Operating revenues	$ 1,250	$ 1,180	$ 1,388	$ 1,283
Operating income	157	158	314	167
Net income	107	117	246	121

	Quarter Ended			
(Millions of Dollars)	March 31, 2019	June 30, 2019	Sept. 30, 2019	Dec. 31, 2019
Operating revenues	$ 1,350	$ 1,185	$ 1,345	$ 1,232
Operating income	167	147	291	182
Net income	113	96	209	125

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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, 2020, 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 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, 2020 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.

PART III

Items 10, 11, 12 and 13 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 RELATIONSHIP AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information required under this Item is contained in Xcel Energy Inc.'s definitive Proxy Statement for its 2021 Annual Meeting of Shareholders, which is incorporated by reference.

ITEM 14 — PRINCIPAL ACCOUNTANT FEES AND SERVICES

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 Proxy Statement for the 2021 Annual Meeting of Shareholders which is expected to be filed with the SEC on or about April 6, 2021. Such information set forth under such heading is incorporated herein by this reference hereto.

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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, 2020.
	Report of Independent Registered Public Accounting Firm — Financial Statements
	Consolidated Statements of Income — For each of the three years ended Dec. 31, 2020, 2019 and 2018.
	Consolidated Statements of Comprehensive Income — For each of the three years ended Dec. 31, 2020, 2019 and 2018.
	Consolidated Statements of Cash Flows — For each of the three years ended Dec. 31, 2020, 2019 and 2018.
	Consolidated Balance Sheets — As of Dec. 31, 2020 and 2019.
	Consolidated Statements of Common Stockholder's Equity — For each of the three years ended Dec. 31, 2020, 2019 and 2018.
2	Schedule II — Valuation and Qualifying Accounts and Reserves for each of the years ended Dec. 31, 2020, 2019 and 2018.
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 June 1, 1995, creating $250 million 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 March 1, 1998, creating $150 million 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 Aug. 1, 2000 (Assignment and Assumption of Trust Indenture)	NSP-Minnesota Form 10-12G dated Oct. 5, 2000	4.51
4.05*	Indenture, dated July 1, 1999, between NSP-Minnesota and 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, dated Aug. 18, 2000, supplemental to the Indenture dated July 1, 1999, among Xcel Energy, NSP-Minnesota and Wells Fargo Bank Minnesota, NA, as Trustee (Assignment and Assumption of Indenture)	NSP-Minnesota Form 10-12G dated Oct. 5, 2000	4.63
4.07*	Supplemental Trust Indenture dated July 1, 2005 between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee, creating $200 million 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 May 1, 2006 between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee, creating $400 million 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 June 1, 2007, between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee	NSP-Minnesota Form 8-K dated June 19, 2007	4.01
4.10*	Supplemental Trust Indenture dated as of Nov. 1, 2009 between NSP-Minnesota and The Bank of New York Mellon Trust Co., NA, as successor Trustee, creating $300 million 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 between NSP-Minnesota and The Bank of New York Mellon Trust Company, NA, as successor Trustee, creating $250 million principal of 1.950% First Mortgage Bonds, Series due Aug. 15, 2015 and $250 million principal amount of 4.850% 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 between NSP-Minnesota and The Bank of New York Mellon Trust Company, NA, as successor Trustee, creating $300 million principal amount of 2.15% First Mortgage Bonds, Series due Aug. 15, 2022 and $500 million 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 between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $400 million 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 between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $300 million 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 Indenture dated as of Aug. 1, 2015 between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $300 million principal amount of 2.20% First Mortgage Bonds, Series due Aug. 15, 2020 and $300 million 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 between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $350 million principal amount of 3.600% First Mortgage Bonds, Series due May 15, 2046	NSP-Minnesota Form 8-K dated May 31, 2016	4.01
4.17*	Supplemental Indenture dated as of Sept. 1, 2017 between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as successor trustee, creating $600 million 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 between Northern States Power Company and the Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $600 million principal amount of 2.90% First Mortgage Bonds, Series due March 1, 2050	NSP-Minnesota Form 8-K dated Sept. 10, 2019	4.01

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4.19*	Supplemental Indenture dated as of June 8, 2020 between NSP-Minnesota and the Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $700 million principal amount of 2.60% First Mortgage Bonds, Series due 2051	NSP-Minnesota 8-K dated June 15, 2020	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 20, 2015	10.02
10.22*+	Summary of Non-Employee Director Compensation, effective as of Sept. 1, 2019	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2020	10.22
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*	Third Amended and Restated Credit Agreement, dated as of June 7, 2019 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, Wells Fargo Bank, National Association, MUFG Bank, Ltd., and Citibank, N.A., as Documentation Agents	Xcel Energy Inc. Form 8-K dated June 7, 2019	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)		

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SCHEDULE II

NSP-Minnesota and Subsidiaries Valuation and Qualifying Accounts
Years Ended Dec. 31

	Allowance for bad debts		
(Millions of Dollars)	**2020**	**2019**	**2018**
Balance at Jan. 1	$ 23	$ 24	$ 21
Additions charged to costs and expenses	24	13	16
Additions charged to other accounts [(a)]	5	7	4
Deductions from reserves [(b)]	(19)	(21)	(17)
Balance at Dec. 31	$ 33	$ 23	$ 24

(a) Recovery of amounts previously written-off.
(b) Deductions related primarily to bad debt write-offs.

ITEM 16 — FORM 10-K SUMMARY

None.

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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. 17, 2021

/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/ BEN FOWKE	/s/ CHRISTOPHER B. CLARK
Ben Fowke	Christopher B. Clark
Chairman, Chief Executive Officer and Director	President and Director
(Principal Executive Officer)	
/s/ BRIAN J. VAN ABEL	/s/ JEFFREY S. SAVAGE
Brian J. Van Abel	Jeffrey S. Savage
Executive Vice President, Chief Financial Officer and Director	Senior Vice President, Controller
(Principal Financial Officer)	(Principal Accounting Officer)
/s/ ROBERT C. FRENZEL	
Robert C. Frenzel	
Executive Vice President, Chief Operating Officer and Director	

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.

Non-Regulated Business Activity Allocation Factors
2022 Test Year Budget

Allocation	Allocation Method	Reasonableness of Allocation Method	Allocation Percent
Labor Related Overhead	Based on employee related expenses, office equipment, and supervision of the service provider.	This allocation represents the relationship between the costs to support labor with labor costs, and is applied to loaded labor.	14.7481%
Corporate Residual	Two-Factor Allocator based on number of employees and revenues relative to NSPM totals.	This allocation represents a fair comparison of the non-regulated business' relative size to the total company and is applied to the prior year actual pool of expenses incurred on behalf of the corporation.	HomeSmart - 0.5674% Customer Owned Street Lighting - 0.0026% Infowise - 0.0020% ConnectSmart - 0.0010%
Customer Accounting	Based on common costs in the FERC Customer Account, Customer Service and Sales Expenses categories relative to NSPM total revenue.	This allocation represents the relationship between the customer accounting costs to total revenue and is applied to non-regulated revenue.	0.7313%