Direct Testimony and Schedules
Laurie J. Wold

Before the South Dakota Public Service Commission
State of South Dakota

In the Matter of the Application of Northern States Power Company
for Authority to Increase Rates for Electric Service in South Dakota

Case No. EL22-___
Exhibit___(LJW-1)

Capital Investments, Depreciation, and Nuclear Decommissioning

June 30, 2022

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Schedules

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Laurie J. Wold. My business address is 401 Nicollet Mall, Minneapolis, Minnesota 55401.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I am employed by Xcel Energy Services Inc. (XES) as a Senior Manager of Capital Asset Accounting. XES is a wholly owned subsidiary of Xcel Energy Inc. and provides an array of support services to all of the operating utility subsidiaries of Xcel Energy Inc., including Northern States Power Company (Xcel Energy, NSPM, or the Company), operating in South Dakota. My Statement of Qualifications is attached as Exhibit__(LJW-1), Schedule 1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. First, I provide information regarding the Company's material capital additions since its last rate case, which was filed in 2014. I then support the underlying information for the calculation of the level of proposed depreciation expense effective January 1, 2023, which includes recommended changes to average service lives, remaining lives, net salvage rates, and depreciation rates, where applicable, for all Company assets used in providing electric service. This includes changes related to the closures of Sherco Units 1 & 2 and adjustments to the remaining lives of Sherco Unit 3 and Allen S. King. I also support the Company's recommendation regarding nuclear decommissioning accruals. Unless otherwise noted, my testimony provides total Company information. Company witness Mr. Benjamin C. Halama includes the South Dakota electric jurisdictional amounts in his pro forma year revenue requirement, which is a 2021 historical test year with 24 months of known and measureable changes.

Q. SPECIFICALLY, WHAT DO YOU ADDRESS IN YOUR TESTIMONY?

A. My testimony addresses three topics: historical capital additions, depreciation expense, and nuclear decommissioning expense. In the capital additions section, I discuss material historical additions which have occurred since the Company's last rate case. In the depreciation section, I present the depreciation changes proposed for the production, transmission, distribution, electric general and intangible, and common general and intangible assets. I discuss the depreciation statistics for all assets in the electric and common utilities. In the nuclear decommissioning section, I present updates to the underlying cost estimate, the fund earnings rates, and the escalation rate. In considering all these areas, it should be kept in mind that the Company's last rate case was filed in 2014 using a 2013 test year.

Q. WHAT IS THE IMPACT OF THE DEPRECIATION CHANGES YOU RECOMMEND?

A. The change in lives and net salvage rates that I propose in my testimony results in a decrease of $9.2 million in Electric Production depreciation expense at a total NSPM Company level and a decrease of $0.5 million for the South Dakota retail jurisdiction. The primary contributing factors to this decrease include, but are not limited to, the impending expiration of Sherco Units 1 & 2 depreciation expense and extending lives at the Nobles and Grand Meadow wind farms, offset by shortening the remaining life at Allen S. King and Sherco Unit 3. The electric transmission, distribution, and general (TD&G) assets accounted for a NSPM Company level increase of $5.2 million and a South Dakota jurisdictional increase of $1.4 million. The overall South Dakota jurisdictional increase, related to the TD&G assets, is primarily driven by the distribution capital additions that are directly assigned to the South Dakota jurisdiction. The NSPM Company common utility assets decreased expense by $11.2 million and the associated South Dakota jurisdictional amount decreased $0.7 million.

These recommended depreciation changes were then applied to the plant and accumulated depreciation balance (i.e., the depreciation reserve) as of January 1, 2023, which included a depreciation passage of time.

The nuclear decommissioning accrual increased by approximately $7.0 million (South Dakota Jurisdictionalized). With respect to the Nuclear Decommissioning Trust accrual, I am recommending the accrual level to be set at $8.2 million due to the need to capture decreases in the expected long term return on trust assets and revisions to amounts to be collected in light of changes in the South Dakota jurisdictional allocation and current underfunding.

Table 1 below summarizes the Company's proposed test year depreciation expense changes.

Table 1

Test Year Depreciation Expense Changes

(in millions)	**Total Company**	**South Dakota Jurisdictionalized**
Electric Production	$ (9.2)	$ (.05)
Electric TD&G	5.2	1.4
Common Utility Assets	(11.2)	(0.7)
Nuclear Decommissioning*	N/A	7.0
Total	$ (15.2)	$ 7.2

*Nuclear decommissioning accruals are calculated at the jurisdictional level and not at the NSPM Total Company level.

II. CAPITAL ADDITIONS

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section, I discuss the Company's historical capital additions for the period 2014 through 2021 (since the Company's last rate case).

A. Capital Additions 2014-2021

Q. WHAT WERE THE COMPANY'S CAPITAL ADDITIONS IN THE PERIOD OF 2014-2021?

A. The Company placed into service capital additions totaling $9.3 billion in the historical period of 2014-2021. Exhibit__(LJW-1), Schedule 2, is a Plant-in-Service Roll forward for the period 2014-2021. Unless otherwise noted, my testimony provides total Company information. Mr. Halama includes the South Dakota electric jurisdictional amounts in his pro forma year revenue requirement.

Q. WHAT WERE THE PRIMARY DRIVERS OF CAPITAL ADDITIONS IN THE 2014-2021 PERIOD?

A. From 2014-2021, the Company made a wide variety of investments across its system to provide reliable, safe, and cost-effective service to its customers. In particular, investments in initiatives and individual projects in the following areas were the primary drivers of the Company's capital additions: wind farms, regional expansion transmission projects, its nuclear generating fleet, a new natural gas combustion turbine, and updating its information technology and business systems. Below, I provide more information about the Company's investments in each of those areas.

Q. PLEASE DESCRIBE THE COMPANY'S INVESTMENTS IN WIND FARMS IN THE 2014-2021 PERIOD.

A. To harness the excellent wind resource of South Dakota and neighboring states and turn it into emissions-free power for its customers—at a time when market pricing of new wind generation was historically low—the Company invested $2.9 billion to build and maintain approximately 2,070 megawatts (MW) of wind farms across the Minnesota, South Dakota, North Dakota and Wisconsin NSP system between 2014-2021. Please see Table 2 presenting the in-service year, actual capital additions, and nameplate capacity for the wind farms in-serviced during the 2014-2021 historical period.

Table 2
Wind Farms

Wind Farm	In-Service	2014-2021 Additions	Nameplate Capacity
Blazing Star 2	2021	$338 M	200 MW
Pleasant Valley	2015	$332 M	200 MW
Freeborn	2021	$321 M	200 MW
Crowned Ridge	2020	$309 M	200 MW
Blazing Star 1	2020	$307 M	200 MW
Courtenay	2016	$284 M	200 MW
Border	2015	$265 M	150 MW
Foxtail	2019	$236 M	150 MW
Lake Benton	2019	$161 M	100 MW
Mower	2021	$158 M	99 MW
Jeffers	2020	$70 M	44 MW
Community Wind	2020	$66 M	26 MW
Nobles	2010	$7 M	200 MW
Grand Meadow[1]	2008	$5 M	100 MW

[1] Note that major classifications for Nobles and Grand Meadows wind farms occured prior to 2014, in 2010 and 2008 respectively, and the additions presented in Table 2 support continuing operations.

These wind projects—and the additional projects the Company has added in subsequent years—will continue to provide substantial benefits to customers. Xcel Energy has been a national leader in wind power since 2005, and wind will continue to play a vital role as the Company works to reduce carbon emissions 80% by 2030 and make progress on its vision to deliver 100% carbon-free electricity by 2050.

Q. ARE THERE ANY WIND FARMS NOT PRESENTED IN TABLE 2 THAT SHOULD BE DISCUSSED?

A. Yes, there are three wind farms, Dakota Range, Northern, and Rock Aetna wind farms, which are not included in the 2014-2021 historical period but will be addressed in the depreciation section of my testimony.

Q. PLEASE DISCUSS THE COMPANY'S INVESTMENTS IN REGIONAL EXPANSION TRANSMISSION PROJECTS IN THE 2014-2021 PERIOD.

A. To meet the growing need for transmission in the region, the Company made capital additions totaling $2.0 billion in regional expansion transmission projects, including projects in South Dakota, North Dakota, and Minnesota as part of the CapX2020 initiative.

These CapX2020 projects were major upgrades to the regional transmission system to support local reliability, regional reliability, and renewable generation. Prior to the CapX2020 projects, there had not been a major upgrade to the Upper Midwest's electric transmission grid in nearly 40 years. Under the CapX2020 initiative, the eleven transmission-owning utilities in Minnesota, North Dakota, South Dakota, and Wisconsin collaborated to study and plan for the future of the regional transmission system. The result was multiple transmission planning studies that supported the development of the Regional Expansion projects.

The Company, through its affiliate Northern States Power Company, a Wisconsin corporation (NSPW), also placed into service a 182-mile 345 kV transmission line from La Crosse, Wisconsin to Madison, Wisconsin in concert with American Transmission Company. This resulted in a total capital addition of $191 million which is recovered through the Interchange Agreement between the Company and NSPW.

Q. PLEASE DESCRIBE THE COMPANY'S NUCLEAR GENERATING FLEET.

A. Xcel Energy owns and operates three nuclear units: one unit in Monticello, Minnesota and two units at Prairie Island in Welch, Minnesota.

Monticello is a single-unit boiling water reactor rated for gross output at 671 MW that was originally licensed by the Nuclear Regulatory Commission (NRC) in 1970. The NRC approved a renewed license for the facility in 2006, allowing the plant to operate through 2030. The Company intends to seek a license extension to allow the plant to operate an additional 10 years, to 2040.

Prairie Island is a two-unit pressurized water reactor, with each unit rated at 550 MW gross output capacity. The NRC licensed Prairie Island's two units in 1973 and 1974, respectively. The initial operating licenses were set to expire in 2013 and 2014. In 2011, the NRC approved renewed licenses for Prairie Island Units 1 and 2, extending their operating lives until 2033 and 2034, respectively.

Nuclear is a critical source of power generation for the Company's customers. Monticello and Prairie Island continue to be two of Xcel Energy's most reliable system-wide baseload electric generation assets, providing almost 30 percent of the electricity to the Company's system in the Upper Midwest. Monticello has operated at an average capacity factor of 94.2 percent, including 99.3 percent in 2018 and 98.6 percent in 2020, both non-refueling years. In that same timeframe, Prairie Island achieved a combined average capacity factor of more than 95 percent, including a 99.9 percent on Unit 2 in 2018; 99.4 percent on Unit 1 in 2019; and 99.3 percent on Unit 2 in 2020, all non-refueling years.

These plants are part of a diverse operating portfolio that provides a hedge against changes in resource availability, fossil fuel prices, and future emissions regulations. They are important sources of low-cost, base-load power that do not have carbon emissions, and their continued safe, reliable, and efficient operation are critical to the Company's commitment to provide reliable and reasonably priced electricity to South Dakota consumers.

Q. WHAT WAS THE COMPANY'S OVERALL INVESTMENT IN ITS NUCLEAR GENERATING FLEET IN THE 2014-2021 PERIOD?

A. To generate reliable, base load, carbon-free power, the Company invested $1.1 billion in its nuclear generating fleet in the period of 2014-2021.

Q. PLEASE SUMMARIZE THE COMPANY'S KEY INVESTMENTS IN ITS NUCLEAR FLEET IN THE 2014-2021 PERIOD.

A. In the 2014-2021 period, the Company invested in mandated compliance projects, such as safety measures required by federal regulators in the wake of the Fukushima nuclear incident in Japan; safety, cybersecurity, and fire-protection improvements; reliability investments including life cycle management, such as an extended power uprate at Monticello and replacement of both main electric generators at Prairie Island; and dry-cask storage for spent nuclear fuel. I provide additional information about those investments below.

Q. PLEASE DISCUSS THE COMPANY'S INVESTMENTS IN NUCLEAR MANDATED COMPLIANCE IN THE 2014-2021 TIME PERIOD.

A. Mandated Compliance includes regulatory, security, and license commitment activities required by Federal or state regulators (normally the NRC), including industry commitments made to the NRC, as well as projects that require NRC approval. The Company made capital additions across Monticello and Prairie Island to implement safety measures required by federal regulators in the wake of the Fukushima nuclear incident in Japan. Such measures included installation of enhanced spent fuel pool instrumentation and modifications to electrical and mechanical systems to augment plant cooling capability.

The Company also made capital additions for its fire-protection program at Prairie Island and at Monticello, all to reduce the likelihood of a fire incident in the first place and reduce the impacts of any fire that may occur. To ensure protection of generating assets and of the public, the Company also made capital additions for its cyber-security program across Monticello and Prairie Island and added physical security at Monticello.

Q. PLEASE DISCUSS THE COMPANY'S INVESTMENTS IN NUCLEAR RELIABILITY IN THE 2014-2021 TIME PERIOD.

A. The Company's investments in reliability projects improve equipment reliability, reduce maintenance activities, and ensure that plants run efficiently and reliably for their full planned lifecycle.

In the 2014-2021 period, the Company completed the Life Cycle Management/Extended Power Uprate work at the Monticello nuclear generating plant that was underway at the time of the company's last South Dakota rate case. The Company also invested in reliability projects at Prairie Island, such as replacement of a reactor coolant pump, process control systems, and a cooling tower. The Company also made a major investment in the replacement of the main electrical generator for both Prairie Island units.

Q. PLEASE DISCUSS THE COMPANY'S CAPITAL ADDITIONS FOR DRY-CASK STORAGE.

A. The Company made capital additions for dry cask storage, which are driven by the Federal government's delay in providing a permanent, long-term spent fuel storage facility, and the requirement that the Company store spent fuel on site in the interim. These investments included storage casks, expansion of the independent spent fuel storage installation at Prairie Island, and the loading of spent fuel into casks at Monticello.

Q. WHAT HAS BEEN THE RESULT OF THE CAPITAL IMPROVEMENTS OF THE NUCLEAR FACILITIES?

A. The projects the Company has undertaken at Prairie Island and Monticello since 2014 have yielded significant benefits for customers and the system. In years where there is only one unit scheduled for a refueling outage, the fleet overall now operates at 95% capacity or above. In 2019, which had two units with refueling outages, the fleet performed at 92.6%. One key reason for this high capacity factor was the record run of over 700 consecutive days at both its Monticello and Prairie Island plants, the longest run of any Xcel Energy nuclear units in its history. The Company's nuclear fleet is more reliable than it has ever been, and O&M costs for the two facilities are down. In addition, as a result of the improvements made in response to the Fukushima incident and the other security, fire protection, reliability and safety capital improvements made since 2014, the facilities, which have operated safely since the 1970s, are now even safer, more secure, and more resilient.

Q. PLEASE DISCUSS THE COMPANY'S INVESTMENT IN A NEW NATURAL GAS COMBUSTION TURBINE.

A. In 2018, the Company placed into service a new natural gas combustion turbine (Unit 6) at our existing Black Dog generating plant in Minnesota. The Company built the new unit to meet a need in the system, and the choice of natural gas reflects the Company's commitment to a robust mix of generation types.

Q. PLEASE DISCUSS THE COMPANY'S KEY INVESTMENTS IN BUSINESS SYSTEMS IN THE 2014-2021 PERIOD.

A. To streamline operations and enable employees to perform responsibilities more efficiently, the Company invested in new business systems, specifically a new SAP General Ledger (GL) system, a new Work and Asset Management (WAM) system, and our new Advanced Distribution Management System (ADMS). The Company put the new GL in service in 2015, and the first WAM deployment went in service in 2016.

Q. PLEASE DISCUSS THE COMPANY'S GL AND ITS GL-RELATED INVESTMENTS.

A. The GL is the Company's financial record-keeping system. The Company's historical system was reaching the end of its life and its vendor was going to cease providing support. Based on its evaluation of options, the Company decided that replacement of the historical GL with a new GL offered by SAP was the best course of action. The new GL provides better analysis of how business drivers impact accounting results and a better ability to trace connections between Generally Accepted Accounting Principles (GAAP) accounting and individual Federal Energy Regulatory Commission (FERC) accounts, among other benefits. These improvements make the Company's operations more efficient.

Q. PLEASE DISCUSS THE COMPANY'S WAM AND ITS WAM-RELATED INVESTMENTS.

A. A WAM system is the core technology for planning and scheduling utility work, managing outages, procuring materials, and managing assets and inventory. Historically, Xcel Energy had three core WAM systems, but the original software vendors were no longer providing full support or upgrades with robust protection against system failure or cyber-attacks. This situation created potential vulnerabilities and made repairs more costly to customers with risk of delays that could jeopardize certain aspects of the Company's day-to-day operations. Accordingly, the Company replaced these three old systems with an integrated solution that is based on current technology and works in tandem with the Company's new GL system.

Q. PLEASE DISCUSS THE COMPANY'S ADMS AND ADMS-RELATED INVESTMENTS.

A. ADMS provides an integrated operating and decision software and hardware support system that allows control room operators, field personnel, and engineers to monitor, control, and optimize the electric distribution system. ADMS gives access to real-time or near real-time data to provide all information on operator console(s) at the control center in an integrated manner and will allow different operating systems and technologies to communicate with each other. ADMS investments began in 2019 with the purchase of servers and the system went into operation in 2021.

Q. PLEASE DESCRIBE THE COMPANY'S METER REPLACEMENT PROJECT INVESTMENTS.

A. The Company began capital additions for the Meter Replacement project in 2019. In his Direct Testimony, Company witness Mr. Marty Mensen provides more detail regarding these investments and the benefits they provide customers.

III. DEPRECIATION

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. The Company is requesting a revision to its remaining lives, net salvage rates, retirement curves, and depreciation rates for its production, transmission, distribution, general, and intangible assets. This section details the changes and includes supporting information for the requested changes.

Q. WHAT IS DEPRECIATION?

A. The term "depreciation" is a system of accounting that distributes the cost of assets, less net salvage (if any), over the estimated useful life of the assets in a systematic and rational manner. Depreciation is a process of allocation, not valuation. However, the amount allocated to any one accounting period does not necessarily represent an actual loss or decrease in value that will occur during that particular period. The Company accrues depreciation on the basis of the original cost of all depreciable property included in each functional property group. On retirement, the full cost of depreciable property, less the net salvage value, is charged to the depreciation reserve.

Q. WHAT IS A NET SALVAGE RATE?

A. Net salvage is the difference between the gross salvage (what the asset or its remaining scrap was sold for) and the removal cost (cost to remove and dispose of the asset). If the removal cost exceeds gross salvage, net salvage is negative. Some plant assets can experience significant negative removal cost percentages due to the amount of removal cost and the timing of any capital additions versus the retirement. Salvage and removal cost percentages are calculated by dividing the current cost of salvage or removal by the original installed cost of the associated assets.

Q. WHY IS IT IMPORTANT TO SET THE RIGHT LEVEL OF DEPRECIATION EXPENSE IN A RATE CASE?

A. The goal in setting depreciation lives and rates is to match depreciation recovery with the useful lives of assets to ensure current customers are equitably paying for the cost of the asset over the period they receive benefits from the assets, avoiding intergenerational inequity. The proposed depreciation rates and associated level of depreciation expense presented reflects the depreciation cost of service and proposed rates effective January 1, 2023.

Q. WHAT CHANGES ARE YOU PROPOSING FOR APPROVED LIVES, NET SALVAGE RATES, RETIREMENT CURVES, OR DEPRECIATION RATES IN THIS CASE?

A. I propose several changes affecting depreciation expense for production assets due to changing the remaining life, updating the dismantling cost that is the basis of the negative net salvage rate, and a reserve reallocation. For transmission, distribution, general, and intangible assets, I propose changes to the average remaining life depreciation rates based on underlying changes to the average service life, retirement curves, and net salvage rates. I discuss the full scope of depreciation expense changes proposed in my testimony below; however, the major drivers to the proposed change in depreciation expense are as follows:

- *Steam Production,* the impending expiration of depreciation expense of Sherco Units 1 & 2 and a proposed reserve reallocation at the Sherco site (Units 1, 2 & 3) and the shortening of the remaining life at Sherco Unit 3 and Allen S. King;
- *Other Production*, extending the remaining life of Nobles and Grand Meadow wind farms, due to wind repowering and the proposed reserve reallocations; and
- *Transmission, Distribution, General, and Intangible (TD&G)*, updating new average service lives, retirement curves, net salvage rates, and depreciation rates for all assets in accordance with the most recent depreciation study and requesting initial parameters for several new accounts or subaccounts of assets.

The depreciation expense changes are supported by several exhibits to my testimony. Exhibit___(LJW-1), Schedules 3-5 are related to the Electric Production segment. Schedule 3 is the 2020 Dismantling Study performed by TLG Services (TLG) on the Company's production assets. Schedule 4 is a summary of the proposed remaining lives and net salvage rates for each plant by FERC account. Schedule 5 is a calculation of proposed net salvage rates and a comparison of net salvage rates currently approved compared to the proposed rates.

Exhibit__(LJW-1), Schedules 6-8 support the average service lives, net salvage rates, and retirement curves for the transmission, distribution, electric general, and common general assets, using plant and depreciation reserve balances at December 31, 2021. Schedule 6 is the 2017 Depreciation Study performed by Alliance Consulting Services (Alliance) on the Company's TD&G assets. Schedule 7 is a summary of the currently approved and proposed average service lives, net salvage rates, depreciation rates, and retirement curve for segment by FERC account. Schedule 8 shows how the proposed depreciation rates were calculated.

Unless specifically stated, all depreciation numbers discussed above and later in my testimony are at total NSPM Company level. Mr. Halama provides the South Dakota jurisdictional costs for the pro forma year in his Direct Testimony.

All of these changes are summarized in Table 3, below, which shows the overall change to depreciation expense by functional class based on 1/1/2023 plant and depreciation reserve balances.

Table 3

Summary of Depreciation Expense Change

Functional Class	**Change in Depreciation Expense (Total Company)**	**Change in Depreciation Expense (SD Jurisdiction)**
Electric Utility		
Steam Production	$1,819,645	$102,488
Hydro Production	(41,318)	(2,334)
Other Production	(11,025,863)	(622,830)
Total Electric Production	($9,247,536)	($522,676)
Transmission	$10,446,259	$590,089
Distribution (SD Located Only)	1,251,588	1,251,588
Electric General	(9,270,171)	(606,601)
Electric Intangibles	2,808,832	183,331
Total Electric TD&G	$5,236,507	$1,418,406
Total Electric Utility	**($4,011,028)**	**$896,031**
Common Utility		
Common General	($11,561,002)	($722,276)
Common Intangibles	333,300	20,035
Total Common Utility	**($11,227,702)**	**($702,241)**
Total Depreciation Expense Change	**($15,238,730)**	**$193,789**

A. Production Assets

Q. PLEASE DESCRIBE THE CHANGES TO PRODUCTION ASSETS AND HOW THIS IMPACTS DEPRECIATION EXPENSE.

A. Production assets use a remaining life method to determine depreciation expense, which is the current net plant adjusted for expected net salvage divided by the current remaining life. The remaining lives for the production assets were evaluated based on the Company's expectations for operating each unit at a generating station, with the common assets (those assets shared by all units) at the generating station assuming the remaining life of the longest-lived unit.

The Company met with the employees who are knowledgeable about the planning, construction, and operations at each facility. During these meetings, the Company reviewed each facility to:

- Understand the major overhauls, rebuilds, and routine construction projects performed in the past few years;
- Consider the scope of current and upcoming projects; and,
- Forecast the likelihood of the facility achieving the currently approved remaining life in light of the past, current, and near future projects.

The Company considers these items along with its plans presented in its current resource planning cycle to understand the operational life of each facility and determine an appropriate remaining life that would be consistent with the likely actual life of a particular facility. Exhibit__(LJW-1), Schedules 3-5 provide detail comparing depreciation expense using currently approved lives and net salvage rates set in 2014 versus using the lives and net salvage rates as proposed in this filing.

For the negative net salvage rates, the Company utilized a comprehensive 2020 Dismantling Study prepared by TLG for all steam, hydro, and other production electric generating plants. The Dismantling Study is included as Exhibit__(LJW-1), Schedule 3.

Q. IN GENERAL, WHAT CHANGES WERE MADE TO REMAINING LIVES?

A. To begin its analysis of remaining lives, the Company incorporated an eight year passage of time adjustment to the last Commission approved remaining lives of all facilities. The passage of time adjustment does not change the annual depreciation accrual, but simply reflects that the Company's production facilities as of January 1, 2022 have aged eight years since January 1, 2014, when the depreciation expense was last updated for the Company.

The Company also adjusted remaining lives to align the terminal retirement date with current expectations. Remaining lives for depreciation purposes have not been updated for South Dakota rates since 2014. Given this passage of time, it is necessary for the Company to update remaining lives with current reality.

Changes to lives within the Other Production function include:

- Angus Anson Units 2&3 to operate through 2040 and Unit 4 to operate into 2045. Unit 3 had a major rotor out overhaul in 2018/2019 and Unit 2 will have a similar overhaul in 2023. This capital expense to rebuild the combustion turbine will extend the life into 2040 per manufacturer recommendations and expectations based on the estimated number of peaking plant unit starts and hours. Unit 4 is being maintained in accordance with manufacturer recommendations. Based on the manufacturer's expectations along with revised estimations of the number of peaking plant unit starts and hours, the Company is anticipating operating the unit until May 31, 2045;
- Black Dog Unit 5 FERC Structures and Improvements account life was extended to match that of the newly completed Unit 6. The Company plans to dismantle the structures at Unit 5 and Unit 6 simultaneously at the retirement date of the unit with the longest life in order to minimize the amount spent to decommission the facility. Therefore, Unit 5 will not be dismantled until Unit 6 is also retired. This practice can be seen in the lives of the Structures and Improvements accounts for several of the Company's other plants including Angus Anson and Blue Lake;

- Blue Lake Units 1-4 extended through June 2023. These units were analyzed based on the number of starts and the hours run, and it was determined that with minimal operating costs, the Company would anticipate them lasting through mid-2023;
- Blue Lake Units 7 & 8's combustion turbines are the same model as Angus Anson Unit 4, and they were installed in the same year. Plant personnel maintain these units on a similar level and timeframe and, therefore, these units are expected to have a similar end of life date. Thus, the Company is requesting a retirement date of May 31, 2045;
- The Luverne Wind-to-Battery asset is to be retired as of January 1, 2021. This is a 1 MW wind energy battery-storage system installed in December 2009, and connected to a nearby 11 MW wind farm formerly owned by Minwind Energy, LLC. When the Minwind facility stopped producing energy in October of 2019 in an effort to terminate its purchased power agreements, the battery was rendered useless. The Minwind interests were sold to NextEra in November 2019, to adhere to the contractual obligations of the PPA, but the turbines remained dormant and have no intention of battery use. Given the battery's age and outdated technology, the Company is retiring the asset. The battery was in-serviced with an initial life of 15 years. The Company is requesting that the Commission approve a $5.6 million reserve reallocation, within the Other function; as is noted below, the Company's proposed Other reserve reallocations will not impact customer rates.
- Wind Repowering at Nobles, Grand Meadows, Border and Pleasant Valley wind farms. Nobles was extended from November 2035 to November 2045, Grand Meadows from November 2033 to November 2043, Border from December 2040 to December 2049, and Pleasant

Valley from December 2040 to December 2049. These extensions, for the wind farms, are driven by the Company's wind farm "repowering" projects which will rebuild wind-power plants with new technology and bigger blades that will extend their life spans. Moderninzing the wind farms with new technology will increase the amount of low-cost, carbon-free wind energy the Company delivers to its customers.

For the steam production function, the notable remaining life changes were shortening the depreciable life for Allen S. King from June 2037 to December 2028 and shortening Sherco Unit 3 from December 2034 to December 2030, as I discuss further below.

Table 4 below summarizes all the generating units, in-service, for which there are changes to remaining lives.

Table 4

Production Remaining Life Changes

Functional Class/Unit	Current depreciable end of life	Proposed Remaining Life (Years) as of January 1, 2023	Expected actual retirement date
Steam Production			
A.S. King	June 2037	6.0	Dec 2028
Red Wing	Dec. 2017	5	Dec. 2027
Sherco Unit 1	Dec. 2022	4	Dec. 2026
Sherco Unit 2	Dec. 2022	1	Dec. 2023
Sherco Unit 3	Dec. 2034	8	Dec. 2030
Wilmarth	Dec. 2017	5	Dec. 2027
Other Production			
Angus Anson Units 2 & 3 (FERC 341)	May 2035	24.4	May 2045
Angus Anson Units 2 & 3 (FERC 342-346)	Oct. 2019	18	Dec. 2040
Angus Anson Unit 4	May 2035	24.4	May 2045
Black Dog Unit 5 (FERC 341)	Dec. 2031	35.3	March 2058
Blue Lake Units 1-4 (FERC 341)	May 2035	22.4	May 2045
Blue Lake Units 1-4 (FERC 342-346)	Dec. 2017	.5	June 2023
Blue Lake Units 7&8	May 2035	22.4	May 2045
Grand Meadow	Nov. 2033	20.9	Nov. 2043
Nobles	Nov. 2035	22.9	Nov. 2045
Wind-to-Battery	Dec. 2023	1	Jan. 2021

Q. ARE THERE NEW PRODUCTION ASSETS WITH NEW REMAINING LIVES?

A. Several new generation units were placed into service since the Company's last rate case. Consistent with the presentation of evidence in the applicable Infrastructure Rider proceedings, the Company is using a 25 year life for wind production assets, and the Company has established a 40 year initial life for Black Dog Unit 6 consistent with the lives assumed for the High Bridge and

Riverside Other Production plants. Table 5 summarizes the new generating units' remaining lives.

Table 5
Remaining Lives on New Production Units

Functional Class/Unit	Remaining Life at 1/1/2023 (in years)	In service Date	Proposed Retirement Date
Other Production			
Black Dog Unit 6	35.3	March-18	March-58
Pleasant Valley Wind	27.0	November-15	December-49
Border Winds	27.0	December-15	December-49
Courtenay Wind	18.9	November-16	November-41
Lake Benton Wind	21.9	November-19	November-44
Foxtail Wind	22.0	December-19	December-44
Blazing Star I Wind	22.3	April-20	April-45
Community Wind North	23.0	December-20	December-45
Jeffers Wind	23.0	December-20	December-45
Crowned Ridge Wind	23.0	December-20	December-45
Blazing Star II Wind	23.1	January-21	January-46
Mower Wind	23.3	March-21	March-46
Freeborn Wind	23.4	May-21	May-46
Dakota Range Wind	24.1	January-22	January-47
Northern Wind	25.0	December-22	December-47
Rock Aetna Wind	25.1	January-23	January-48

Q. ARE THERE ANY NEW PRODUCTION ASSETS PLANNED TO GO INTO SERVICE AFTER THE 2021 HISTORICAL TEST YEAR AND DURING THE 24-MONTH KNOWN AND MEASURABLE PERIOD?

A. Yes. There are two new wind facilities that are planned to be placed into service in 2022 and one in 2023. They include Dakota Range Wind in January of 2022, Northern Wind in December of 2022, and Rock Aetna Wind in January of 2023. The Company proposes that these production assets use a 25-year life from their respective in-service dates.

Q. IN GENERAL, WHAT CHANGES WERE MADE TO THE PRODUCTION NET SALVAGE RATES?

A. Every five years, The Company commissions a Dismantling Study to determine net salvage rates for its production assets. The Company's 2020 Dismantling Study is included as Exhibit__(LJW-1), Schedule 3, and it is a site-specific cost estimate for all of the Electric Production assets, including Hydro Production assets. The main purpose of the 2020 Dismantling Study was to estimate the present-day costs for retiring and demolishing the facilities, also known as final removals of existing facilities. A complete list of the assumptions used in the cost estimates is included in my Schedule 3.

Q. WHAT CHANGES TO THE PRODUCTION NET SALVAGE RATES ARE BEING PROPOSED?

A. Except for a few units, the general trend is toward a more negative net salvage rate due to the increasing costs of removal. The Hydro Production Hennepin Island and Upper Dam units show a slight decrease in cost of removal as well as Nobles Wind. Exhibit__(LJW-1), Schedule 5, is the comparison of present and proposed net salvage rates. To calculate the proposed negative net salvage rates, the Company took the dismantling cost estimate for the entire facility and allocated it to each unit. Once allocated to each unit, the unit dismantling cost is divided by the unit's plant balance at January 1, 2022 to get the negative net salvage rate for each unit. The proposed percent changes to the net salvage rates for production assets are summarized in Table 6 below.

Table 6

Production Net Salvage Rate Changes

Functional Class/Unit	Change in Net Salvage Rate (%)	Change in removal reserve by end of life (in millions)
Steam Production		
Allen S. King	-3.7%	$26.4
Red Wing	1.2%	$(0.8)
Sherco Unit 1	-9.9%	$76.2 (combined U1 & U2)
Sherco Unit 2	-9.9%	
Sherco Unit 3	-3.2%	$21.2
Wilmarth	-1.6%	$0.9
Hydro Production		
Hennepin Island	+3.5%	($0.7)
St. Croix Falls	-7.5%	$0.2
Upper Dam	+3.5%	($0.2)
Other Production		
Angus Anson Units 2 & 3	-6.9%	$5.9
Angus Anson Unit 4	-1.9%	$0.9
Black Dog Unit 5	-5.5%	$14.5
Blue Lake Units 1-4	-16.7%	$4.5
Blue Lake Units 7 & 8	-6.4%	$5.0
Grand Meadow Wind	-3.7%	$7.5
High Bridge	-1.1%	$4.3
Inver Hills	-9.3%	$5.4
Nobles Wind	+0.2%	($1.2)
Riverside	-7.2%	$24.0
Wind-to-Battery	-135.6%	$5.6

Q. FOR THE PRODUCTION ASSETS GOING INTO SERVICE AFTER THE 2021 HISTORICAL TEST YEAR, WHAT IS THE RECOMMENDED NET SALVAGE RATE?

A. Please see Table 7 below presenting the net salvage rates for new plants, which were not in service in the 2021 historical test year. For wind farms that weren't included in the 2020 distmantling study, the Company used a simple average of the net salvage percentages from the eight wind farms included in the 2020 Dismantling Study, which was negative 10.4 percent.

Table 7

Net Salvage Rates for New Plants

Unit	Current Net Salvage %	Proposed Net Salvage %
Black Dog Unit 6	-5.%	-10.3%
Blazing Star 1	-8.5%	-11.3%
Blazing Star 2		-10.4%
Border Winds	-6.6%	-9.5%
Community Wind		-10.4%
Courtenay Wind	-6.9%	-10.4%
Crowned Ridge Wind		-10.4%
Dakota Wind **		-10.4%
Foxtail Wind	-6.4%	-9.4%
Freeborn Wind		-10.4%
Jeffers Wind		-10.4%
Lake Benton	-8.5%	-10.5%
Mower Wind		-10.4%
Northern Wind **		-10.4%
Pleasant Valley	-8.5%	-11.7%

Q. PLEASE SUMMARIZE THE PROPOSED CHANGES TO DEPRECIATION EXPENSE FOR THE PRODUCTION ASSETS.

A. All of these changes are summarized in Table 3, above, which shows the overall $9.2 million NSPM Total Company decrease and $0.5 million South Dakota jurisdictional increase to depreciation expense by functional class based on plant and depreciation reserve balances as of January 1, 2023. Mr. Halama provides the revenue requirement impact of these changes for the pro forma year in his Direct Testimony.

B. Theoretical Reserve and Reserve Reallocation

Q. WHY DOES THE COMPANY PROPOSE A RESERVE REALLOCATION AND WHAT IS THE IMPACT ON DEPRECIATION EXPENSE?

A. Reserve reallocation is when the book reserve is realigned among accounts within a functional group based on the theoretical reserve for each account within that function. The Company proposes to perform a reserve reallocation in this proceeding because it results in a reduction to book depreciation expense and levelizes the impacts to customers. The proposed reallocation shifts reserves within the other and steam functions. The primary drivers for the steam and other functions' reserve reallocations are the impending expiration of depreciation expense at Sherco Units 1 & 2, shortening of the remaining life of Sherco Unit 3, and the under-recovery of the Luverne Wind2Battery asset. The reallocation is based on the theoretical reserves calculated in the Depreciation Study.

Q. WHAT IS THE THEORETICAL RESERVE IN A DEPRECAITION STUDY?

A. The theoretical reserve represents the portion of a property group's cost that would have been accrued as depreciation reserve if current expectations were used throughout the life of the property group for future depreciation accruals. The theoretical reserve for the asset group serves as a point of comparison to the book reserve to determine if the unrecovered investment of the asset and its removal cost are over or under-accrued.

Q. HOW DOES THE DEPRECIATION STUDY DETERMINE THE THEORETICAL RESERVE?

A. In the Depreciation Study, NSPM computed theoretical reserves based on projected plant balances as of December 31, 2021. The theoretical reserve was then calculated using a reserve model that relies on a prospective concept relating future retirement and accrual patterns for property, given current life and salvage estimates. More specifically, the theoretical reserve of a property group was determined from the estimated remaining life of the group, the total life of the group, and estimated net salvage. This computation for the straight-line, remaining-life theoretical reserve ratio, which is described in more detail starting on page 19 of Exhibit___(LJW-1), Schedule 5, involves multiplying the vintage balances within the property group by the theoretical reserve ratio for each vintage. The calculation used in the Depreciation Study is the same calculation the Company used to develop the depreciation rates approved by the Commission in the Company's most recent Electric Rate Case, which was Docket No. EL14-058.

Q. HOW DOES THE THEORETICAL RESERVE RELATE TO THE RESERVE ALLOCATION?

A. As part of the Depreciation Study, a depreciation reserve reallocation was performed, which is based on the theoretical reserves calculated in the Depreciation Study. If the accumulated book depreciation reserve as compared to the theoretical reserve results in some assets being over-recovered (a positive value when subtracting the theoretical reserve from the book reserve) and others being under-recovered (a negative value when subtracting the theoretical reserve from the book reserve) within the functional class or group, then this difference can be used to rebalance the accounts within the functional class or group using the reserve reallocation.

Q. DID YOU ALIGN THE COMPANY'S DEPRECIATION RESERVE WITH THE LIFE AND NET SALVAGE CHARATERISTICS OF THE ASSETS IN EACH FUNCTION?

A. Yes. In the process of analyzing the Company's depreciation reserve, I observed that the depreciation reserve positions of the accounts were generally not in line with the life and net salvage characteristics found in the analysis of the Company's assets. To allow the relative reserve positions of each account within a function to mirror the life and net salvage characteristics of the underlying assets, I reallocated the depreciation reserves for all accounts within each function. Since the basis of the current depreciation rates incorporates different average service lives and net salvage percentages from the proposed parameters in this case, I believe reserve reallocation is the best approach based upon sound depreciation practice to resolve the differences in reserve position.

Q. DOES THE REALLOCATION OF THE DEPRECIATION RESERVE CHANGE THE TOTAL RESERVE?

A. No, the reallocation of the depreciation reserve does not change the total reserve. The depreciation reserve represents the amounts that have been collected as a systematic allocation of the cost of an asset over its useful life, including any net salvage that may be required to remove that asset from service upon retirement. The reallocation process does not change the total reserve for each function; it simply reallocates the reserve between accounts in the function. The reallocated depreciation reserves agree in total to the projected reserve balances at December 31, 2021.

Q. IS DEPRECIATION RESERVE REALLOCATION A SOUND PRACTICE?

A. Yes. Depreciation reserve allocation is a sound and recognized depreciation practice. The National Association of Regulatory Utility Commissioners endorsed the practice in its 1968 publication of Public Utility Depreciation Practices, explaining that reallocation of the depreciation reserve is appropriate "…where the change in the view concerning the life of property is so drastic as to indicate a serious difference between the theoretical and the book reserve."[2] Additionally, the 1996 edition of Public Utility Depreciation Practices states that "theoretical reserve studies also have been conducted for the purpose of allocating an existing reserve among operating units or accounts."[3]

With respect to the Company, Alliance's Depreciation Study demonstrates that there have been significant changes in the life and net salvage characteristics of the property since the current accrual rates were established. These changes have created a significant difference between the theoretical and the book reserve in each functional group, which makes the reallocation of the depreciation reserve appropriate in this instance.

Q. WHY IS IT IMPORTANT FOR THE DEPRECIATION RESERVE TO CONFORM TO THE THEORETICAL RESERVE?

A. It is important for the depreciation reserve to conform to the theoretical reserve because this sets the reserve at a level necessary to sustain the regulatory concept of intergenerational equity among the Company's customers, as well as sets the depreciation rates at the appropriate level based on current parameters and expectations.

Q. PLEASE EXPLAIN HOW THE REALLOCATION OF DEPRECIATION RESERVES IS CONDUCTED IN THE DEPRECIATION STUDY.

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[2] Public Utility Depreciation Practices, published by the National Association of Regulatory Utility Commissioners, at page 48 (1968).

[3] Public Utility Depreciation Practices, published by the National Association of Regulatory Utility Commissioners, at page 188 (1996).

A. To start, the total theoretical reserve for asset groups within each function is computed. Then, to reallocate depreciation reserves within each function using the theoretical reserve model, a proration factor is computed by developing a ratio of the total book reserve to the total theoretical reserve by functional class. After each theoretical reserve was computed, it is multiplied by the proration factor to derive the reallocated book reserve of each functional group. After computing the reserve reallocation, the recommended depreciation rates and expense were calculated in Exhibit__(LJW-1), Schedules 4 and 7 for the Company's plant in service assets.

Q. ARE THERE ANY UNIQUE CIRCUMSTANCES WITH THE RESERVE REALLOCATIONS PROPOSED IN THIS PROCEEDING?

A. Yes. The primary reason the Company proposes a reserve reallocation in this proceeding is to mitigate customer rate impacts. The reserve reallocation, which most significantly mitigates customer impacts, occurs at the Sherco steam production site. As presented in Table 3 of my testimony, the current proposed change to the South Dakota jurisdictional depreciation expense, which incorporates reserve reallocations, is a reasonable $193,789.

Q. PLEASE EXPLAIN THE SHERCO SITE RESERVE REALLOCATION.

A. The Sherco site is comprised of three units: Units 1, 2 & 3. The current retirement dates for Sherco Units 1 & 2 are Dec-2022 for both units and Dec-2034 for Sherco 3. The Company is proposing to extend the remaining life at Sherco Units 1 & 2 to 2026 and 2023, respectively, and shorten the life at Sherco Unit 3 from 2034 to 2030. The Sherco Unit 3 remaining life reduction aligns with the Company's plan to retire the plant in 2030, as described further by Company witness Ms. Farah Mandich in her Direct Testimony. In this proceeding, the Company has updated remaining lives and net salvage percentages, which both directly impact depreciation expense. The impact of the proposed net salvage change for Units 1 & 2, increased from -5.1% to -15.0%, which results in an increase of $72.0 million of removal costs, and at Sherco Unit 3 an increase from -4.3% to -7.5% produces a $25.2 million increase of removal costs. These additional removal costs are reasonable and necessary to recover and properly dismantle the units. With the short proposed remaining lives at Sherco Units 1 & 2, if the Company did not perform a reserve reallocation, the $72 million would need to be recovered over a short period, which would significantly increase the Company's filed revenue requirement. This increase or spike, due to the increased removal costs and short recovery time, would ultimately flow to and increase customer rates if not remedied. To mitigate this spike, the Company proposes a reserve reallocation. The reserve reallocation shifts reserve balances from Sherco Unit 3, which has capacity and a longer recovery period, to Sherco Units 1 & 2. The removal cost recovery of the $72 million, formerly responsible for Units 1 & 2 in the short-term, will be assigned to Sherco Unit 3, which has a longer remaining life to recover over. By shifting reserve balances, the Company achieves its objectives to "smooth" the depreciation expense and mitigate customer rate spikes. The $72 million of removal costs will be recovered; the Company is simply proposing to vary the timeline of the recovery in order to mitigate customer rate impacts.

Q. ARE THERE ANY OTHER FACTORS THAT SUPPORT THE COMPANY'S PROPOSED RESERVE REALLOCATION AT SHERCO?

A. Yes. From a practical perspective, it makes sense to reallocate the reserves and removal cost recovery as described above because while the plant contains three separate units, the Sherco facility is a single generating station. The turbines for the different Sherco Units are all immediately adjacent to one another on the same floor in the same building, meaning it would be virtually impossible to decommission and dismantle Sherco Units 1 & 2 without decommissioning Sherco Unit 3 as well. Therefore, it is reasonable to reallocate the reserve in order to recover the remaining costs from a view of the life of the entire Sherco generating station, because the facility will not be dismantled until the final unit (Unit 3) retires.

Q. ARE THERE ANY ADDITIONAL RESERVE REALLOCATIONS PROPOSED IN THIS PROCEEDING?

A. Yes. There are a few, much less material reserve reallocations in the Steam Production and Other Production functions to ensure full recovery of the plant and removal costs without impact to customer rates.

C. TD&G Assets

Q. WHAT ARE TD&G ASSETS?

A. TD&G assets refer to all assets in the transmission, distribution, and general functional classes of assets. General assets can be either electric utility only (e.g. communication equipment which specifically supports only the electric segment) or common utility (e.g. a service truck which can be deployed to support either gas or electric repairs). Common utility assets are allocated out to the electric and gas segments based on various allocation methods.

Q. WHAT IS THE PURPOSE OF A TD&G DEPRECIATION STUDY?

A. A depreciation study is a comprehensive analysis of all TD&G assets in order to determine the statistical parameters for each account or group of assets to set depreciation rates and lives. The depreciation study encompasses four distinct phases. The first phase involves data collection and field interviews. The second phase is an initial data analysis. The third phase evaluates the information and analysis. Finally, the fourth phase involves the calculation of depreciation rates and documents the corresponding recommendations.

Q. WHEN WAS A TD&G DEPRECIATION STUDY LAST PERFORMED?

A. The Company directed Alliance Consulting Group to perform a comprehensive Depreciation Study (2017 Alliance Study) for the TD&G assets for the electric, gas, and common utilities. This study is performed every 5 years so the next study will be performed in 2022. Although gas assets were included in the 2017 Alliance Study, they are not part of this proceeding. All Company assets were included in the 2017 Alliance Study regardless of where they were located. The 2017 Alliance Study is included as Exhibit__(LJW-1), Schedule 6.

In the 2017 Alliance Study, the Company reviewed the depreciable lives and net salvage rates for TD&G assets. The analysis included interviews with operating personnel responsible for purchase, maintenance, and utilization of the equipment. For the 2017 Alliance Study, the lives were adjusted if factors such as market forces, manufacturer expected life, technological obsolescence, business planning, known causes of retirement, and changes in expected future utilization affected the useful life of the asset.

Q. PLEASE PROVIDE AN OVERVIEW OF THE ANALYSIS THAT WAS DONE TO DETERMINE DEPRECIATION RATES FOR TD&G ASSETS.

A. The 2017 Alliance Study was only used for the resulting statistics (average service life, net salvage rate, and retirement curve) and not for the determination of the depreciation rate. The calculation of the average remaining life depreciation rate was done by Company personnel using the South Dakota depreciation reserve in conjunction with the depreciation statistics from the 2017 Alliance Study. The 2017 Alliance Study is included as Exhibit__(LJW-1), Schedule 6. Exhibit__(LJW-1), Schedule 7, compares the presently approved depreciation rates and parameters to the proposed values. The depreciation rate calculation is shown in Exhibit__(LJW-1), Schedule 8.

As a result of the comprehensive 2017 Alliance Study, the Company proposes new depreciation lives, net salvage rates, retirement curves, and depreciation rates for TD&G assets in this filing to better reflect the expected useful lives of its assets as well as removal costs and expected salvage. In general, depreciation lives are lengthening slightly and net salvage rates are becoming more negative, with the exception of FERC Accounts 392 and 396, due to increasing removal costs and decreasing gross salvage values. The Company also continues the use of an Average Remaining Life (ARL) method. This method allows an automatic true-up of differences created between the theoretical and actual reserves over the remaining lives of the assets.

Q. AS A RESULT OF THE 2017 ALLIANCE STUDY, WHAT CHANGES TO ELECTRIC TRANSMISSION AVERAGE SERVICE LIVES AND NET SALVAGE RATES ARE BEING PROPOSED?

A. For electric transmission accounts, the lives for half of the accounts increased. There are seven accounts, three that have increasing lives, one that had a decreasing life, and the lives of the other three accounts were unchanged. The account with the greatest change in life is FERC Account 354, Transmission Towers and Fixtures, which increased by five years. There is also a trend toward higher negative net salvage, with five accounts increasing (i.e., more negative) and their negative net salvage and the remaining two accounts remaining unchanged. The account with the largest increase in negative net salvage is FERC Account 355, Poles and Fixtures, where the net salvage moved from negative 35 percent to negative 50 percent. The increased cost of removal is primarily due to union wage increases. There is a new account included for the first time, FERC Account 359, Roads and Trails. There are currently no assets in this account; it was added in anticipation of future additions. The average service life was set at 60 years with a zero net salvage rate.

Q. WHAT CHANGES TO ELECTRIC DISTRIBUTION AVERAGE SERVICE LIVES AND NET SALVAGE RATES ARE BEING PROPOSED?

A. There are 12 existing electric distribution accounts, of which six have increasing lives, one has a decreasing life, and the lives of the other five accounts are unchanged. The accounts with the greatest change in life are FERC Account 366, Underground Conduit, and FERC Account 367, Underground Conductor and Devices, both of which moved four years longer in life. There is also a trend toward higher negative net salvage with eight accounts increasing (i.e., more negative) their negative net salvage, one account decreasing its negative net salvage, and the remaining three accounts remaining unchanged. The account with the largest increase in negative net salvage is FERC Account 364 Distribution Poles, Towers, and Fixtures where the net salvage moved from negative 100 percent to negative 120 percent. This is similar to the increased cost of removal in Transmission. The analysis of distribution assets used only South Dakota located assets. There are three new depreciation sub-accounts added to FERC Accounts 369 and 370 which are intended to support electric vehicles and AGIS. Currently there is no balance in these accounts. In the event plant is added to these accounts, the Company requests authorization to use average lives of 10 years for FERC Account 369 Electric Vehicle Supply Infrastructure, 20 years for FERC Account 370 Meters - AGIS plant, and 10 years for FERC Account 370 Electric Vehicle Chargers. No net salvage rates are expected for these assets, as any costs of removal are expected to be offset by salvage.

Q. WHAT CHANGES TO ELECTRIC GENERAL AVERAGE SERVICE LIVES AND NET SALVAGE RATES ARE BEING PROPOSED?

A. For electric general accounts, the lives for most of the accounts remained the same. There are 18 accounts, four that have increasing lives, four that have decreasing lives, and the lives of the other 10 accounts were unchanged. The account with the greatest change in life is FERC Account 392.3, Trailers, which moved three years shorter in life. There is also a slight trend toward higher positive net salvage with five accounts increasing their positive net salvage and the remaining 13 accounts remaining unchanged. The account with the largest increase in positive net salvage is FERC Account 392.3, Trailers, where the net salvage moved from zero percent to positive 20 percent.

Q. WHAT CHANGES TO COMMON GENERAL AVERAGE SERVICE LIVES AND NET SALVAGE RATES ARE BEING PROPOSED?

A. For common general accounts, the lives for most of the accounts remained the same. There are 15 existing accounts, three that have increasing lives, four that have decreasing lives, and the lives of the other eight accounts were unchanged. The account with the greatest decrease in life is FERC Account 390, Structures and Improvements, which moved five years shorter in life. There is also a slight trend toward higher positive net salvage with five accounts increasing their positive net salvage, one account increasing its negative net salvage, and the remaining ten accounts remaining unchanged. The account with the largest increase in positive net salvage is FERC Account 392.3, Trailers, where the net salvage moved from zero percent to positive 20 percent. The account with the largest increase in negative net salvage is FERC Account 390, Structures and Improvements, where the net salvage moved from negative 20 percent to negative 25 percent.

Additionally, the Company is proposing a new subaccount under FERC Account 397 Communication Equipment for Smart Grid assets, specifically, the Field Area Network (FAN) equipment which supports the Meter Replacement program. The Company is proposing a 10-year Average Service Life with a zero net salvage percent, which means that the expected salvage will equal the cost to remove the equipment. This is consistent with the current parameters of other similar communication assets. These assumptions result in a 10.00 percent initial depreciation rate.

Q. WHAT OTHER PROPOSED CHANGES TO COMMON GENERAL, IN THIS PROCEEDING, WOULD YOU LIKE TO DISCUSS?

A. In compliance with a December 13, 2019 Order issued by the Minnesota Public Service Commission (MPUC), the Company has completed a review of the building assets included in FERC Account 390 – Structures and Improvements – in order to determine which assets should continue to be group depreciated and which assets should be separately depreciated. As part of the review and in response to a request from the Minnesota Department of Commerce, the Company has separately accounted for depreciation for the small number of "high-value" buildings in FERC Account 390, the retirement of which "could have a significant impact on the depreciation expense of the account as a whole."

Q. WHAT CHANGES TO ELECTRIC AND COMMON INTANGIBLE AVERAGE SERVICE LIVES AND NET SALVAGE RATES ARE BEING PROPOSED?

A. For both electric and common intangible accounts, no life or net salvage changes are recommended to existing accounts. FERC Account 302, Franchises and Consents, has been added to the schedules, and these assets are amortized over the term of the individual franchise agreements. Also, a new sub account for FERC Account 303, Software, was added for the new large base computer systems for the General Ledger and Work and Asset Management. This group has a proposed average life of 15 years. Common intangible had previously approved categories of three, five, seven, and ten year lives. Electric intangible only had a five-year life category. Therefore, the Company is adding new sub accounts to the electric utility so each utility has the categories of three, five, seven, ten, and fifteen year lives in anticipation of future additions.

Q. IS THE COMPANY PROPOSING TO CONTINUE THE USE OF AVERAGE REMAINING LIFE DEPRECIATION RATES FOR TD&G?

A. Yes.

IV. NUCLEAR DECOMMISSIONING TRUST

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. This section addresses the changes to the calculation of the nuclear decommissioning accrual that have occurred since the the Company's last rate case, filed in 2014. There is a new engineering cost estimate, updated escalation and earnings rates, current bank balances, and elimination of the Escrow Fund that must now be reflected in current rates.

Q. WHAT IS THE NUCLEAR DECOMMISSIONING ACCRUAL?

A. Nuclear decommissioning accrual is the method used to accumulate the final removal costs for the Company's three nuclear units. The amounts collected through general rates are deposited externally in a trust fund per Nuclear Regulatory Commission (NRC) rules. The annual accruals are calculated from a detailed engineering cost estimate for removal of the plant and of storage of the fuel until the federal government takes possession of all the fuel assemblies. These accruals are then invested by professional asset managers in a risk-mitigating strategy to grow the accrued amount while hedging losses.

This is in contrast to how the Company addresses dismantling costs for its other production assets, where the dismantling costs are not segregated into a trust account nor invested.

Q. WHAT CHANGES ARE YOU RECOMMENDING?

A. The Company is proposing to increase the annual nuclear decommissioning accrual for the South Dakota jurisdiction from $1,234,251 set in Docket EL12-046 to $8,192,630. Nuclear decommissioning accruals are calculated at the jurisdictional level and not at the total NSPM Company level. This accrual is calculated for a 60-year DECON scenario, which is in line with NSPM's other jurisdictions, and is the industry requirement from the NRC.

Q. HOW IS THE NUCLEAR DECOMMISSIONING ACCRUAL AMOUNT DETERMINED?

A. Using an engineering cost study for the basis of decommissioning costs, the Company partners with Goldman Sachs Asset Management (GSAM), the trust fund administrators, to obtain labor and non-labor escalation rates as well as operational and post-shutdown earning rates on the fund for each of the nuclear units throughout the decommissioning of each facility.

Q. WHAT IS CAUSING THE NUCLEAR DECOMMISSIONING ACCRUAL TO INCREASE?

A. The increase is driven primarily by an increase in the estimate of removal costs. The current accrual was approved in the 2012 rate case, and was based upon the 2011 cost study. This proceeding uses the 2020 cost estimate. The study was performed in 2020 and provided costs in 2020 dollars. Both studies were prepared by TLG Services, the engineering consultant the Company has historically used to prepare these estimates. TLG Services has extensive industry experience and currently provides estimates for the majority of nuclear production plants in the country. A comparison of the nominal cost estimates to decommission are in Table 8 below. Additionally, there was a decrease in the earnings assumption of the trust.

Table 8
Nominal Cost Estimate to Decommission

Year of Study	Monti	PI1	PI2	Total
2011	$ 1,163,818,832	$ 700,574,802	$ 832,756,232	$ 2,697,149,866
2020	$ 1,612,762,003	$ 1,017,864,701	$ 1,029,940,789	$ 3,660,567,493
Change in Estimate	**$ 448,943,171**	**$ 317,289,899**	**$ 197,184,557**	**$ 963,417,627**

Q. WHAT EARNINGS AND ESCALATION RATES ARE BEING USED TO CALCULATE THE NUCLEAR DECOMMISSIONING ACCRUAL?

A. The accrual calculation is run on each unit using two single effective earnings rates, one rate for the operating period (radiological) and one for the post-shutdown period (spent fuel/site restoration). These rates, which reflect the anticipated amount of investment proceeds the Company expects to earn on the funds in trust, are calculated and provided by GSAM, based on asset allocation recommendations made at the same time as the development of the 2020 cost estimate. The operating period rates are 3.92 percent for Monticello, down from 5.35 percent in 2011; 3.94 percent for Prairie Island Unit 1, down from 5.50 percent in 2011; and 4.02 percent for Prairie Island Unit 2, down from 5.53 percent in 2011. The post shutdown period rates are 3.30 percent for Monticello, down from 4.82 percent in 2011; 2.98 percent for Prairie Island Unit 1, down from 4.66 percent in 2011; and 2.90 percent for Prairie Island Unit 2, down from 4.57 percent in 2011. Cost escalation rates were also provided by GSAM. The cost escalation rates in the 2020 study are 4.22 percent for labor costs and 3.02 percent for non-labor costs. This is not directly comparable to the Operations rate of 3.63 percent and the post decommissioning rate of 2.63 percent that was used in the 2011 study, but it uses the same base assumptions around inflation and wage increase rates.

Table 9

Earnings Rates Changes

Nuclear Unit	**Period**	**2011 Return**	**2020 Return**	**Change**
Monticello	Pre-decommission start	5.35%	3.92%	-1.43%
Monticello	Post-decommission start	4.82%	3.30%	-1.52%
PI Unit I	Pre-decommission start	5.50%	3.94%	-1.56%
PI Unit I	Post-decommission start	4.66%	2.98%	-1.68%
PI Unit II	Pre-decommission start	5.53%	4.02%	-1.51%
PI Unit II	Post-decommission start	4.57%	2.90%	-1.67%

Q. WHAT IS THE BALANCE FOR SOUTH DAKOTA IN THE QUALIFIED TRUST?

A. The accrual calculation uses qualified trust balances as of December 31, 2021. The market value of the fund, net of expected taxes on unrealized gains, for each unit for the South Dakota jurisdiction issued as a starting point for each unit's accrual calculation. Exhibit_LJW, Schedule 9, shows the balances of the funds as of December 31, 2021 used to calculate the accrual, and Table 10 shows the balance by unit.

Table 10
Qualified Trust Fund Balance by Unit
June 30th, 2020

Monticello	$1,076,666,911
Prairie Island 1	622,498,987
Prairie Island 2	695,439,515
Total	$2,394,605,413

Consistent with the Company's 2012 Filing in Docket No. EL12-046 regarding the then-existing nuclear decommissioning escrow account, the beginning balance of the trust also includes the pour-over of the then-existing escrow funds. In addition to the South Dakota jurisdictional fund balances, past wholesale balances are expected to be reallocated across all jurisdictions. When this reallocation occurs, South Dakota will realize a benefit for these dollars as they impact the beginning balance of future decommissioning accruals.

Q. DOES THE COMPANY'S TREATMENT OF THE NUCLEAR DECOMMISSIONING ACCRUAL REQUESTED IN THIS PROCEEDING ALIGN IT WITH ITS OTHER JURISDICTIONS?

A. Yes. The Company is currently using the 2017 Triennial Nuclear Decommissioning proceeding in Minnesota (Docket No. E002/M-17-828, submitted December 1, 2018) as the basis for the nuclear decommissioning accrual in Minnesota. This study was adjusted in the 2019 Integrated Resource Plan to integrate the effects of the DOE refunds. The Company believes the same outcome should be used in South Dakota as well.

Q. WHAT IS THE DEPARTMENT OF ENERGY (DOE) REFUND?

A. These are payments related to the DOE's partial breach of its contract to begin accepting spent nuclear fuel beginning on or before January 31, 1998. Under settlement, the DOE has agreed to pay for costs associated with its failure to begin taking spent fuel in 1998 including: a) any additional pool storage costs and other plant modifications; b) dry casks storage and costs directly related to such storage (e.g., internal labor, overhead, operation and maintenance, training and security); and c) additional property taxes resulting from the on-site dry cask storage or other plant modifications. The Company has historically refunded the amount paid by the DOE under this settlement to customers in the year received.

Q. PLEASE SUMMARIZE THE INTERACTION OF THE ACCRUAL AND THE DOE SETTLEMENT PAYMENTS FOR THE SOUTH DAKOTA JURISDICTION.

A. Currently, the DOE settlement payments allocated to South Dakota are being refunded to customers as received. In other jurisdictions, these amounts have been used to offset accrual increases and avoid rate increases. The Company is proposing in this case to utilize projected future DOE reimbursements after shutdown to offset the expected costs associated with spent fuel disposal within the NDT accrual. The Company has incorporated the DOE offset using a 75 percent scenario. This percentage designates how much of the future expected spent fuel costs will be offset by DOE reimbursements. In the amounts calculated for this case, the Company is assuming a 75 percent scenario as a conservative approach; the recommended range could include up to 90 percent of the DOE reimbursements. The Company used a third-party consultant[4] in the 2017 Triennial Nuclear Decommissioning to validate that the Company's inclusion of these funds is reasonable.

Q. WHAT IS THE END-OF-LIFE (EOL) NUCLEAR FUEL ACCRUAL?

A. The EOL Accrual is a cost recovery mechanism that reserves for the unspent and unamortized nuclear fuel that is in the reactors at the time the nuclear reactors are shut down. These reserves accrete over the life of the plant through a periodic expense, similar to other end of life and removal reserves.

Q. HOW DOES THE END-OF-LIFE (EOL) NUCLEAR FUEL ACCRUAL WORK?

A. The EOL Accrual and Decommissioning Accrual both function by setting funds aside for known future obligations. However, the EOL Accrual is different in that its funds are held within the Company as opposed to a separate trust. Because of this, there is an offset to rate base for the cumulative EOL funding. Customers receive offsetting benefit from this funding through a reduction in rate base and in the resulting reduction in general rates.

The intent of EOL recovery is that the cumulative effect of the accrual and corresponding rate base reduction will maintain a constant annual net cost to customers over time. The EOL rate base reduction and accruals collected are

[4] Adam Levin is a sole proprietor doing business as AHL Consulting, delivering consulting services to the commercial nuclear power industry and the U.S. Department of Energy, providing expertise in all areas of decommissioning and spent nuclear fuel (SNF) management strategy, operations and finances.

put into rates in the Company's general rate case filings. At that point both are in parity – meaning that for the first year the customer pays the full accrual amount and receives the full benefit of the rate base impact through rates. However, in future years the customer needs to be compensated for the additional offset to rate base that it should receive for the contributions it has made since the general rate was approved. To compensate for this, the assumed accrual increases to an amount that includes the rate base impact the customer should receive. In this way, the customer is credited for the benefit they should receive by essentially investing the assumed return into the EOL fund balance. As such, every year that passes, the assumed accrual will increase without an increase to rates, to compensate for the assumed interest until another general rate case is filed and ordered on. At this point, the higher accrual is put into rates, offset by a larger rate base offset.

In summary, the EOL Accrual increases annually without an increase in rates as a result of the compensating effect of the assumed interest on the rate base reduction. This process resets or rebalances every time a new general rate case is filed where the rate base benefit is adjusted to reflect the past amount contributed.

Q. IS THE COMPANY PROPOSING A REVISION TO THE EOL NUCLEAR FUEL ACCRUAL IN THIS CASE?

A. Yes. Based on updated assumptions around the cost of fuel and the how the fuel will be used in the reactors, the amount the Company needs to recover has decreased from the last approved filing. In the 2020 Triennial Filing, this accrual was approved for $1,042,656 effective in 2023.

V. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The Company has made considerable investments in the NSP System since the last rate case was filed in 2014 to help maintain safe, reliable, and affordable electric service to its customers. Many of these investments have already been deemed prudent by the Commission in various proceedings, and those that have not are prudent.

The Company must update its depreciation expense given the passage of time since its last rate case. The changes in its depreciation expense are consistent with current known and assumed remaining lives of its production plant, currently known net salvage rates, and other considerations. Additionally, the Company's proposed TD&G depreciation rates are consistent with appropriate studies and conform to past practice. Overall, the Company's proposed depreciation rates are reasonable and should be approved by the Commission.

Also given the passage of time since its last rate case, the Company must increase amounts accrued to fund the Nuclear Decommissioning Trust. The costs to fund the trust are a necessary component of providing the benefits of a strong nuclear fleet to our customers, are reasonable, and should be approved by the Commission.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.