PUBLIC VERSION

STATE OF MINNESOTA
BEFORE THE PUBLIC UTILITIES COMMISSION

Katie Sieben	Chair
Dan Lipschultz	Vice Chair
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
John Tuma	Commissioner

In the Matter of the Petition of Northern States Power Company d/b/a Xcel Energy for Approval of the 2019 Review of Remaining Lives.

DOCKET NO. E002,G002/D-19-161

COMMENTS OF THE OFFICE OF THE ATTORNEY GENERAL

I. INTRODUCTION

The Office of the Attorney General—Residential Utilities and Antitrust Division ("OAG") respectfully submits the following Comments in response to Xcel Energy's 2019 Remaining Lives petition. The Company proposes to change the depreciation of certain assets that would reduce its annual depreciation expense by approximately $9.3 million. In addition, the Company has provided updated projections on the dismantling costs of its generation facilities. For the reasons set forth below, the OAG makes the following recommendations: (1) the Commission should deny the Company's request to extend the plant remaining lives at this time, and delay action on this issue until after the Commission approves the Company's next Integrated Resource Plan ("IRP"); (2) the Commission should order Xcel to provide the total cost of the wind projects it seeks to add to its depreciation expense, including AFUDC; (3) the Commission should order Xcel to move any reserves in excess of removal costs from Minnesota Valley to the plants in which reserves were moved from; (4) the Commission should disallow any reserve reallocations to cover removal costs for three plants that are closed and no longer

used and useful;[1] and (5) the Commission should order the Company to include Granite City in its annual reporting on dismantling costs.

II. BACKGROUND

The Company filed its 2019 Review of Remaining Lives petition on February 19, 2019 and requested a reduction of its annual depreciation expense by $9.3 million. This net reduction is made up of several components. The two major components are the Company's proposal to extend the useful lives of eight of its electric generation facilities, which would decrease depreciation by $13.4 million, and its proposal to place three new wind farms into service in the later months of 2019, which would increase depreciation by $4.1 million.[2]

Additionally, the Company filed updated information on its internal cost estimates for removing the Minnesota Valley plant and Black Dog Units 3 & 4. The Company has compared these internal cost estimates to the dismantling cost estimates it obtained from TLG Services, Inc. ("TLG") in 2015 as part of its comprehensive dismantling study for its electrical generation plants. The Company's comparison showed some differences between the previous TLG cost estimates used to collect depreciation reserves from ratepayers and the Company's current forecast for removal costs.

III. ANALYSIS

A. XCEL'S REQUESTED DEPRECIATION EXPENSE

Xcel has requested an overall decrease in its depreciation expense by $9.3 million. This proposal is made up of two parts. First, Xcel seeks to increase the remaining lives of several of its generating units. Second, Xcel seeks to place three new wind farms into service. The OAG is concerned about Xcel's request to increase the remaining lives of its generating units. In

[1] Black Dog Units 3 & 4, Key City, and Granite City.
[2] Petition at 5.

addition, Xcel has not provided all of the information necessary to evaluate its proposal to add new wind farms to its depreciated assets. These issues are discussed in turn below.

1. Life Extension Request for Electric Production Facilities.

The Company is requesting remaining life extensions for eight electric production facilities. As shown below, this would decrease the annual depreciation expense by approximately $13.4 million.

Table 1: Xcel Proposed Changes to Production Facilities

Plant	Increase/(Decrease) in life	Increase/(Decrease) in expense
Sherco Units 1&2	1 year	($7,135,065)
Sherco Unit 3	1 year	($1,023,525)
Sherco Unit 3 Deferral	1 year	($29,596)
Angus Anson Units 2&3	15 years	($1,477,648)
Angus Anson Unit 4	10 years	($641,237)
Black Dog 5 (FERC 341 only)	26.3 years	($989,028)
Blue Lake Units 1-4	4 years	($1,046,143)
Blue Lake Units 7&8	10 years	($1,092,241)
Total Impact		**($13,434,483)**

While the net result of these adjustments is a decrease in Xcel's annual depreciation expense, the OAG is concerned that this may not accurately reflect the remaining lives of these plants or be the most prudent long-term decision for ratepayers. If these are not accurate estimates, ratepayers could be unnecessarily stuck with higher costs in the future.

There are two concerns that the OAG has with Xcel's proposal. First, Xcel has proposed extending the life of some of its plants without considering the Company's upcoming IRP. Second, Xcel is proposing to delay the dismantling of part of its Black Dog Unit 5 facility until its Unit 6 facility is shut down.

a. Extending Units' Lives Outside the IRP Process.

Xcel has proposed to extend the useful lives of several of its generation plants outside the IRP process. First, the Company states that it would like to extend Sherco Units 1 and 2 from

January 1 to December 31 of 2023 and 2026, respectively.[3] The Company notes that the Commission "accepted the Department position, resulting in January 1 retirement assumptions for each unit" in its last IRP."[4] Regardless, Xcel claims that "we intend to run these units throughout the entire calendar year leading up to retirement."[5] It is not appropriate for the Company to unilaterally decide to bypass the Commission's order and change the assumed depreciation date. Accordingly, the Commission should deny Xcel's request to extend the lives of the Sherco 1 and 2 plants.

Second, Xcel requests extending the lives of its Sherco 3, Angus Anson, and Blue Lake facilities. For these plants, Xcel relies primarily on engineering analysis that estimates the time that these plants *could* potentially operate. For Sherco 3, Xcel relies on a Life Expectancy report from 2013.[6] For the other facilities, Xcel relies on the OEM equipment equivalent starts ("ES") recommendations, which reflect manufacturers' recommendations.[7]

The problem with these estimates is that they do not consider the policy or cost factors that may cause the Company or the Commission to shutter these plants before their operational lives expire. This is important because the Company is preparing to file its IRP in three months. The IRP process will presumably provide parties with better information about the future operation of these assets. Changing the remaining lives now, before additional and more holistic information on the Company's generation resources is reviewed through the upcoming IRP filing is premature, and could likely result in a depreciation expense that is out-of-step with decisions

[3] Xcel's Response to DOC information request 3, attached as Exhibit 1.
[4] *Id.*
[5] *Id.*
[6] Xcel's Response to DOC information request 11, attached as Exhibit 2.
[7] Xcel's Response to DOC information requests 4, 5, 7, and 8, attached as Exhibits 3, 4, 5, and 6.

made in the upcoming IRP regarding generation resources.[8] Accordingly, the Commission should deny the Company's request to change the remaining lives of these facilities at this time, and delay any action until after Xcel's next IRP.

b. Delay of Black Dog Unit 5 Dismantling Costs.

Xcel is also seeking to extend the remaining life for one portion of the Black Dog Unit 5 facility—the amount included in FERC account 341-Structures and Improvements. This structure houses both Units 5 and 6. The Company states it will save money if the structure is dismantled once, at the end of both units' lives, rather than when each unit ceases to be in operations.[9] Accordingly, the company proposes to extend the amount for Unit 5 for approximately 26 years to coincide with the remaining life of Unit 6.

The OAG is concerned with the Company's plan to extend the remaining life for the Black Dog Unit 5 structure because it is not clear whether Xcel has considered the impact of 26 years of inflation on the dismantling costs. Inflation would presumably increase these costs over time, perhaps substantially. It is possible that the increased costs of waiting 26 years to remove the housing for Units 5 will outweigh any benefit gained by removing the entire facility at one time. This could also result in intergenerational inequities, since future ratepayers would be required to pay for the shortfall on removal costs of a facility that closed 26 years prior. While the OAG understands that removing the entire structure at once may provide some cost savings, the Company should analyze in its reply comments whether these benefits outweigh inflationary impact of delaying the removal of the portion that houses Unit 5. Additionally, the Company should confirm in its reply comments that parts of Black Dog Unit 5 not included in the 241 –

[8] Xcel also claims that capital investments it is making in its Angus Anson units 2 & 3 support is request to extend their remaining lives. *See* Exhibit 5. These investments may or may not impact the remaining life of the facility in the company's next IRP. For this reason, these investments should not impact the remaining lives of these facilities until the Commission reviews Xcel's next IRP.

[9] Xcel's Response to DOC information request 6, attached as Exhibit 7.

Structures and Improvements account would be immediately dismantled after operations are ceased.

2. Wind Farm Additions.

The Company has also requested that three wind farms (Blazing Star I, Foxtail, and Lake Benton) be included in the depreciation filing because they are projected to be used and useful in September and December of 2019.[10] This would increase the Company's annual depreciation expense by approximately $4.1 million.

The three wind farms that Xcel seeks to add to its depreciation expense were included in the Wind Portfolio that was approved in the Company's Wind Generation Acquisition petition in 2016.[11] In that proceeding, the Commission ordered two important protections for ratepayers. First, it stated that it "will hold Xcel accountable for the prices and terms used to evaluate each of the selected projects for the purpose of cost recovery from Xcel ratepayers."[12] Second, it approved Xcel's proposed aggregate cap for the costs of its self-build projects.[13] Xcel's proposed aggregate cap included all costs for AFUDC.[14]

In this case, the OAG requested information from Xcel on its projected costs for each of these windfarms, and a comparison of how these costs compared to the cost caps ordered in the Wind Generation Acquisition docket. The company's responses provided some costs, but did not include the AFUDC.[15] This does not appear to be consistent with Xcel's proposal or the

[10] Petition at 9 and 10.
[11] MPUC Docket No. E-002/M-16-777.
[12] *In the Matter of the Petition of Xcel Energy for Approval of the Acquisition of Wind Generation from the Company's 2016-2030 Integrated Resource Plan* , MPUC Docket No. E-002/M-16-777, ORDER APPROVING PETITION, GRANTING VARIANCE, AND REQUIRING COMPLIANCE FILING at 10 (Sep. 1, 2017).
[13] *Id.*
[14] *See In the Matter of the Petition of Xcel Energy for Approval of the Acquisition of Wind Generation from the Company's 2016-2030 Integrated Resource Plan*, MPUC Docket No. E-002/M-16-777, PETITION at 3 (Oct. 24, 2016).
[15] Xcel's Response to OAG information requests 4, 5, and 6, attached as Exhibits 8, 9, and 10.

Commission's order in the Wind Generation Acquisition docket. Accordingly, the Company should provide the total cost of these projects in its reply comments, including AFUDC, compared to the cost caps, including AFUDC, that was ordered in the Wind Generation Acquisition petition in 2016. The Company should also provide current cost details on any other farms that were approved in the Wind Generation Acquisition, and how those farms' costs, including AFUDC, compare to the cost cap.

B. DISMANTLING COST COMPARISON

The OAG has previously expressed concern with Xcel's repeated practice of re-allocating the reserve amounts from one plant to another in order to cover any shortfalls for removal costs. Allowing this practice creates intergenerational inequities among ratepayers while eliminating the Company's incentive to accurately forecast and manage its removal costs. While the Commission has allowed this practice in certain cases, Xcel's current filing demonstrates why this decision should not be continued as a default practice.

The Company's filing includes updated projections for its removal costs. These projections show that Xcel's past TLG projections were not accurate, and that its practice of moving reserve balances between plants is not a sustainable way to address any shortfalls. In fact, Xcel's practice of moving its reserve balances among plants has simply caused the need to move additional money to undo problems the Company created. In this case, the Company has an excess balance in its Minnesota Valley reserve balance, after moving money into this account. The Company also has a deficit in its Black Dog Units 3 & 4 reserve balance, after moving money out of these accounts. Finally, the Company has not provided an update of its reserve balance for Key City. The OAG's analysis suggests, however, that Xcel does not have a sufficient reserve balance to cover its remaining removal costs.

First, Xcel projects that its reserve balance for Minnesota Valley are $7.4 million more than the Company's estimate of removal costs. This is significant because part of this reserve was moved from other plants to account for a previously-estimated shortfall.[16] This supposed shortfall has now been replaced with a surplus. Accordingly, the Commission should order that Xcel return the excess reserve for the Minnesota Valley plant to those plants that the reserves were moved from during prior remaining lives filings. This would allow ratepayers to benefit from lower depreciation expenses on these plants in the future, or offset any dismantling costs for these plants.

Second, Xcel now projects that the depreciation reserves for Black Dog Units 3 & 4 are $5.2 million less than the Company's estimate of removal costs. The Company states that this variance is due to its larger estimated contingencies and that it does not expect to incur cost overruns.[17] This is important, because the Company previously requested and received a $2.9 million reserve reallocation from Black Dog Units 3 & 4 to seven other generation plants.[18] At that time, the Company argued that it had *excess reserves* that it could use to offset the deficits for other plants. In that proceeding, the OAG recommended that the requested reserve reallocation be denied. The OAG raised the concern that allowing these reallocations would minimize the need for Xcel to accurately estimate its removal costs going forward:

> . . . altering the depreciation reserves . . . [w]ill only serve to obfuscate the issue of inaccurate dismantling estimates by Xcel and mask the associated consequences to various generations of ratepayers. Additionally, the question of whether Xcel is adequately planning and properly including sufficient removal

[16] *In the Matter of the Petition of Northern States Power Company for Approval of the 2015 Review of Remaining* Lives, MPUC Docket No. E,G002/D-15-46, PETITION at Attachment B at 8-9 (May 18, 2015). These plants included Black Dog, Allen S. King, Red Wing, Sherco, and Wilmarth.
[17] Petition at 14.
[18] MPUC Docket No. E,G002/D-15-46.

> costs in depreciation rates has been asked in previous filings, and is an issue that Xcel has not fully addressed in this current filing.[19]

The OAG's previous concerns with regard to reserve reallocations are still applicable in this proceeding. The Company previously assured the Commission that it had excess reserves for Black Dog Units 3 & 4, and used those purported excess reserves to cover the costs of removing other plants. It should not now be able to raid reserve balances from other plants to fix this mistake. Accordingly, with the exception of returning the excess reserves from the Minnesota Valley plant mentioned above, the Commission should order Xcel to expense any removal cost overruns for Black Dog Units 3 & 4, and disallow recovery of it from ratepayers.

Finally, the OAG is concerned that Xcel will request another reallocation of reserve balances from some of its generation plants to its Key City and Granite City facilities in the future. Xcel has not requested any reserve reallocation to these plants in this proceeding, and states that it is still updating its cost projections from the TLG estimate.[20] Since Xcel has not provided a current cost projection, the OAG performed a variance analysis of the reserve balances for the Key City and Granite City plants compared to the TLG cost estimates. The analysis shows that the reserve balances for these plants appear to be unreasonably low.

The table below shows the potential shortfall after factoring the inflationary impact on the cost estimate from 2014 through 2019, and could end up being even larger if the dismantling work does not begin in 2019.

[19] *In the Matter of the Petition of Northern States Power Company for Approval of the 2015 Review of Remaining* Lives, MPUC Docket No. E,G002/D-15-46, COMMENTS OF THE OFFICE OF THE ATTORNEY GENERAL (July 17, 2015).
[20] Xcel's Response to OAG information request 2, attached as Exhibit 11.

Table 2: Key City & Granite City Reserves and Cost Estimates

	Key City	Granite City
Reserve Balance	$ 4,093,558	$ 4,230,678
TLG Cost Estimate (2014 dollars)	$ 4,096,222	$ 4,423,449
Inflation Impact on Cost (2015-2019)	$ 426,338	$ 460,396
Total	$ 4,522,560	$ 4,883,845
Shortfall	**$ (429,002)**	**$ (653,167)**

Notably, Xcel has previously reallocated $776,000 of reserves from nine operating facilities to the Key City plant in its 2015 depreciation filing, in order to cover a shortfall at that time. Rather than closing the plant, the Company opted to keep it in a "dormant state" from when it ceased operations in 2012 to the present, in order to provide spare parts for its Granite City plant.[21] The result is that the removal costs for Key City have likely increased over time with inflation. The Company should therefore explain whether or not any spare parts were actually taken from Key City to be used on Granite City during this time, and whether the cost of keeping Key City dormant was actually offset by the cost savings of not having to purchase parts for Granite City. The Company should also explain whether it intends to sell any parts from Key City and Granite City when the facilities are removed, and whether the proceeds would be used to cover any dismantling reserve shortfall.

As in earlier Xcel depreciation filings, the OAG opposes reserve reallocations for plants that are closed and no longer used and useful.[22] The utility has the responsibility to accurately forecast and collect sufficient reserves to cover any dismantling costs from ratepayers so that the ratepayers who benefit from the use of a plant fully cover the cost to dismantle it. Xcel's recent practices of reallocating depreciation reserves from existing in-service facilities to cover

[21] MPUC Docket No. E,G-002/D-17-147.
[22] MPUC Docket Nos. E,G002/D-15-46 and E,G-002/D-17-147.

shortfalls for other facilities is not sustainable. It causes intergenerational inequity because current ratepayers who do not benefit from a closed plant will have to pay for the removal costs, and the Company is not held accountable for accurately estimating and collecting the cost of dismantling the plant from ratepayers while the plant is still in-service. While this practice has been allowed in the past, this case shows that it has not resolved Xcel's underlying forecast inaccuracies and that it will continue to be used as a way for the company to retroactively fix past mistakes.

IV. CONCLUSION

For the reasons set forth above, the OAG makes the following five recommendations in response to Xcel's Petition:

(1) the Commission should deny the Company's request to extend the plant remaining lives at this time, and delay action on this issue until after the Commission approves the Company's next IRP;

(2) the Commission should order Xcel to provide the total cost of the wind projects it seeks to add to its depreciation expense, including AFUDC;

(3) the Commission should order Xcel to move any reserves in excess of removal costs from Minnesota Valley to the plants in which reserves were moved from;

(4) the Commission should disallow any reserve reallocations to cover removal costs for three plants that are closed and no longer used and useful; and

(5) the Commission should order the Company to include Granite City in its annual reporting on dismantling costs.

Dated: April 22, 2019

Respectfully submitted,

KEITH ELLSION
Attorney General
State of Minnesota

s/ Shoua Lee
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Financial Analyst

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OFFICE OF THE ATTORNEY GENERAL –
RESIDENTIAL UTILITIES AND ANTITRUST
DIVISION

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Xcel Energy Information Request No. 3
Docket No.: E002,G002/D-19-161
Response To: MN Department of Commerce
Requestor: Gemma Miltich
Date Received: February 28, 2019

Question:
Reference(s): Pages 5-7 of Xcel's Petition

Please provide the support, in the form of an engineering study or other appropriate analysis, which led Xcel to determine that Sherco Units 1 and 2 will operate through December 31, 2026 and December 31, 2023, respectively.

Response:
As noted on page 6 of our Petition, during the 2015 Review of Remaining Lives (Docket No. E,G002/D-15-46) (the "2015 Petition"), the 2015 Integrated Resource Plan (IRP) process was also underway. The IRP listed the retirement years of Sherco 1 in 2026 and Sherco 2 in 2023. Depending on whether one assumed a retirement on January 1 of those years versus December 31, this can lead to a one year difference in the remaining life. In light of the Company's revised IRP proposal, the Department of Commerce (DOC) recommended the Commission base the remaining lives for Sherco 1 and 2 in the 2015 Petition on retirement dates of January 1, 2026 and 2023, respectively. Commission Staff in the briefing papers stated, "Staff believes that the one year difference is not significant and the Commission could accept either proposal." In its November 23, 2015 Order, the Commission accepted the Department position, resulting in January 1 retirement assumptions for each unit. The IRP Order that followed "approve[d] the retirement of Sherco 2 in 2023, and Sherco 1 in 2026."

The Company has now determined we intend to run these units throughout the entire calendar year leading up to retirement. Thus, we are using December 31 of each respective retirement year to set the remaining life. Therefore, to align the remaining life with the anticipated operational retirement date, we are proposing to extend the remaining lives of Sherco 1 and 2 by one year. Our determination to run the units

Exhibit 1

until the conclusion of each retirement calendar year is not driven by an engineering study or analysis but rather by operational and resource planning considerations.

Preparer:	Michael Mitchell
Title:	Plant Director
Department:	Sherco Plant
Telephone:	763.261.3110
Date:	March 11, 2019

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Xcel Energy Information Request No. 11
Docket No.: E002,G002/D-19-161
Response To: MN Department of Commerce
Requestor: Gemma Miltich
Date Received: February 28, 2019

Question:
Reference(s): Pages 6-7 of Xcel's Petition

Please provide the support, in the form of an engineering study or other appropriate analysis, which led Xcel to determine that Sherco Unit 3 will operate through December 31, 2035.

Response:
Please see Attachment A to this response which was submitted as Schedule 6 to the Direct Testimony of Company witness Ms. Lisa H. Perkett in our 2013 electric rate case (Docket No. E002/GR-13-868).

For more information, please see our response to DOC IR No. 3.

Preparer: Michael Mitchell
Title: Plant Director
Department: Sherco Plant
Telephone: 763.261.3110
Date: March 11, 2019

Exhibit 2

Ms. Lisa Perkett
Xcel Energy Services, Inc.
414 Nicollet Mall, 4th Floor
Minneapolis, MN 55401

October 78 2013

Dear Lisa,

At your request, I have reviewed the technical analysis that Black and Veatch (B&V) conducted for the Sherco Unit 3 engineering and economic life, reviewed detailed information on the plant, had broad-ranging discussions with Sherco Subject Matter Experts and conducted an inspection of the plant. As a result, I can provide an informed opinion on the appropriate depreciable life for the unit.

As you are aware, I have had twenty years' experience at a Fortune 100 utility in property accounting, depreciation, engineering and valuation and have managed fixed asset accounting for regulated entities and non-regulated entities and an additional 10 years as Managing Partner of Alliance Consulting Group. Alliance provided depreciation analysis for utilities across the US. I have significant experience as an expert witness in depreciation, valuation and rate base areas and have provided testimony and support in many state regulatory commission dockets. In addition to having held a number of national industry roles related to depreciation and property accounting, including twice chairing the Plant Accounting and Valuation Committee of the Edison Electric Institute, I have attended all the classes offered by the Depreciation Programs, Inc. (DPI) and continue to refresh my training by attending (and teaching) various depreciation related seminars across the country. I served as general editor of the industry publication "Introduction to Depreciation and Net Salvage of Public Utility Plant and Plant of Other Industries", have been contributing editor of other industry publications and I am a frequent speaker at conferences on depreciation related issues. I am a Licensed Professional Engineer in the State of Texas (PE) and a Certified Depreciation Professional (CDP).

The majority of the assets at a generating unit will generally retire at the same time – at its final retirement date. Depreciation of generating units requires an estimate of the final retirement date in order to recover investment over the period of time the property is used to provide service to customers. The most important factor in determining the depreciation rate for a generating unit is the estimate of the final retirement date.

Coal-fired power plants consist of a large number of individual assets (such as pumps, motors and boiler tubes) which have a finite life. These individual assets fail and must be replaced in order for the plant to continue in operation. In addition, throughout a plant's life, the utility performs capital projects (including projects required to comply with regulatory requirements). However, at some point in time, these expenditures become so costly that the more prudent course is to retire the entire plant and all of its many components.

After reviewing the analysis, I believe the B&V analysis was thorough and comprehensive as it relates to the engineering-related forces that could factor into the life for Sherco Unit 3. From the B&V analysis and my understanding of the unit's facts and circumstances, I concur with the recommendation that Sherco Unit 3's life be maintained at its current 21 year remaining life. Given that the boiler equipment is the critical path to retirement for the unit at this point and there were no major boiler capital improvements related to the failure of the turbine-generator, there is no discernible reason to move the life of the unit from its existing end date.

While the turbine-generator set was restored after the incident, many of the components were reused, rebuild or replaced with used "like-kind" equipment. For example, the exciter was replaced with a used exciter of nearly the same vintage from another plant. My understanding (and the discussion from the B&V report) was that there was no intent to bring the turbine-generator set back to "new" condition but to bring it to approximately the same condition as prior to the failure. As such, even without the limiting factor of the boiler equipment, the rebuild would not warrant a change in the life of the unit.

While there are some projected future capital expenditures that may have an impact on the life of the unit at a future point in time (primarily large boiler-related expenditures and the addition of environmental control equipment), the expenditures are still outside of a reasonable time frame to consider in setting depreciable lives and, to some degree, are still speculative as to when or if they will occur. Without the budgeted boiler plant replacements, Xcel Subject Matter Experts believe that it may be possible to continue to operate the unit through the currently projected life (with the appropriate escalating level of Operating and Maintenance available), but that the capital expenditures for the boiler would be required to potentially extend the life of the unit. As is common practice in setting lives for depreciation purposes, only when the expenditures are made that will affect the life of the unit should the life of the unit be reconsidered. That way, the

additional capital to be depreciated and any additional life that the capital additions may promote will be synchronized.

Given the above considerations, it is my opinion that the current 21 year remaining life for Sherco Unit 3 is still appropriate and reasonable for use in setting depreciation rates and expense.

Sincerely,

Dane Watson
Managing Partner
Alliance Consulting Group

REPORT ON LIFE EXPECTANCY OF COAL-FIRED POWER PLANT

Sherburne County Generating Station

Unit 3

B&V PROJECT NO. 181267
B&V FILE NO. 28.0000

PREPARED FOR

Xcel Energy

OCTOBER 14, 2013

BLACK & VEATCH
Building a world of difference.

Exhibit 2

Table of Contents

Exhibit 2

1.0 Summary

Black & Veatch (B&V) was contacted by representatives of Xcel Energy who requested an assessment or opinion regarding the remaining useful life of the Sherburne County Unit 3 generating plant. Xcel Energy explained that the unit was in the process of returning to service after an incident in which the turbine generator was damaged. The Minnesota Public Utility Commission has ordered that Xcel Energy request an independent assessment of the remaining useful life of the unit as one of the primary inputs to establish a reasonable period over which to depreciate the capital investment in the plant.

1.1 APPROACH

In this report Black & Veatch provides a discussion of the remaining life of the Xcel Energy Sherburne County (Sherco) Unit 3 and the primary drivers of the useful life of any generating unit. Black & Veatch based the evaluation on data provided by Xcel Energy regarding the plant's current condition, typical end of life mechanisms for fossil fired generating plants and our knowledge of depreciation practices typically used by utilities and Public Service Commissions in the U.S. The sections of this report that follow will discuss the design life, a limited condition assessment and recent findings from a survey of typical industry depreciation practices. The depreciation survey includes a recent consideration of life spans of other US coal plants, and engineering and environmental compliance considerations.

The B&V evaluation is focused on the evaluation of the remaining life. Our assessment specifically considered typical end of life drivers for the major components of the generating plant in comparison to the condition of the specific equipment at Sherco Unit 3. This condition evaluation was based on information and reports provided by Xcel Energy and industry information available from the major systems Original Equipment Manufacturers (OEM's). The condition information provided by Xcel Energy included Outage and Inspection reports, planned capital expenditures, and historical performance/operations information.

1.2 FINDINGS:

After review of the available information regarding the condition of the generating unit and industry practice it is the opinion of Black & Veatch that the restoration efforts with respect to the Sherburne County Unit 3 turbine generator should have no significant impact on the overall remaining physical life of the unit.

It is our understanding that the work performed returned the turbine generator to the conditions immediately prior to the event of November 19, 2011. The remaining useful life of the plant as a whole is a function of the condition of the entire plant and not any single component. The life limiting factor or system most likely to define the end of the economic and useful life of the station will be the boiler.

There are two major influences that will in all likelihood lead to a finding that the boiler has reached the end of its useful life. The first is a finding that due to creep[1] a major header or other component in the boiler is no longer functional. The second is the need for significant environmental control equipment due to a regulatory compliance driver.

[1] Creep is the tendency of a solid material to move slowly or deform permanently under the influence of mechanical stresses.

2.0 Discussion

The following sections provide a discussion of the findings from the Black & Veatch study efforts. This includes a summary condition assessment, based on information provided by Xcel Energy, and discussion of the primary drivers of the useful life of a modern power generation facility.

2.1 TURBINE RESTORATION

The original steam turbine generator equipment was supplied by General Electric and was placed in operation in 1987. The turbine has operated reliably until the unit restart following the November 2011 planed outage to upgrade the HP/IP turbine sections. During that restart, on November 19, 2011, the entire turbine train suffered major damage when several blades were separated during startup requiring complete turbine disassembly and subsequent restoration. Extensive examinations, engineering evaluations and repairs were completed on the affected components to restore them to pre-event condition.

HP-IP Turbines - HP and IP turbines were replaced with an Alstom design in 2011. Components in the front standard were damaged and repairs completed. During disassembly the HP Inner shell would not separate on site and the entire inner shell and rotor were sent out for inspection and repair. The lower half outer shells were removed to facilitate repairs and regrouting of the turbine base plates.

LP Turbines – The LP turbine rotors were removed and inspected. The rotors, and all components were inspected, repairs made and buckets replaced. The lower half outer shells were removed to facilitate repairs and regrouting of the turbine base plates.

Generator - The generator sustained extensive damage to both the rotor and stator/core during the failure event. The stator laminations were completely removed on site and the stator was completely restacked vertically. Both turbine end and collector end outer end shields were extensively damaged, and they were repaired. The inner end shields were also refurbished but only minor repairs were required. Other components were replaced with new parts, including bearings, H2 seals, oil deflectors, bushings, current transformers, etc. The generator rotor stub shaft was broken off from the main generator shaft. A new bolted on stub shaft was designed by the OEM and extensive rotor repairs were made to all areas of the rotor. Other than the rotor body and copper windings, all other rotor components were replaced.

Exciter - The LP turbine failure resulted in complete destruction of the exciter stator and rotor. There was also substantial damage to the rectifier's banks in the exciter doghouse. A used exciter from another utility was purchased, inspected and refurbished by the OEM. The U3 voltage regulator was replaced with a new digital General Electric EX2100E excitation system. The Sherco 3 Fall 2011 overhaul and uprate outage included replacement of the rectifiers with a new GE water cooled design.

Condenser – Severe damage occurred to the condenser tubes caused by the broken turbine components. The condenser tubes were replaced. During retubing, two of the tube sheets were

found to be eroded below acceptable thickness and were also replaced. All tube sheets were coated with a plastic coating to ensure longevity.

2.2 DESIGN LIFE

Analysis of steam plant lives is heavily influenced by the engineering design life. When a new plant is initially placed in service, its projected life will generally equal its engineering life. As a unit ages, it is reasonable to reevaluate life span by considering the condition of the plant components, actual plant use and experience, additional capital expenditures for the unit, and potential environmental costs and risks. The following sections discuss design life, the major components of steam plants, and factors that lead to component failure and ultimately influence plant life.

Based on discussions with Original Equipment Manufacturers (OEMs), the expected or design "life" of a major power plant component such as the steam generator (boiler) or the turbine-generator is determined by various factors. The actual age of a piece of equipment is seldom the determining factor; rather a combination of utilization, specific design, maintenance, and environment determines the expected useful life. The sections that follow will focus on the two major plant systems that may impact the life of the unit (boiler and turbine/generator) and discuss each of those determining factors.

2.2.1 Boiler Discussion

As is the case with turbines, the actual age of a piece of equipment is not the primary determining factor of expected life, rather a combination of hours connected to load, the pattern and practice of use, specific design, fuel quality, water quality and chemistry, and maintenance procedures determine the expected useful life.

Babcock and Wilcox published information that describes the typical expectation for specific equipment replacement. Babcock and Wilcox's "Steam" states, "high temperature creep rupture and creep fatigue failure are the two main aging mechanisms in the high temperature components of high temperature boilers. All components that operate above 900° F are subject to some degree of creep. As a result, most of the components have a finite design life and can fail after 20 to 40 years of operation."

A table of typical tube life by general duty is provided below in Table 1. These are general industry recommendations and not based on specific findings or condition assessment of Xcel Energy's Sherco 3 boiler. Although in kind replacement of worn or damaged tubes is not expected to trigger New Source Review (NSR) requirements, a Legal and Environmental assessment would be recommended to confirm this assumption prior to making major changes to steam generator heat transfer surfaces.

Table 1
Example Component Replacement Schedule for a Typical High Temperature, High Pressure Boiler[2]

Typical Life (Years)	Component Replaced	Cause for Replacement
20	Miscellaneous tubing	Corrosion, erosion, overheating
25	Superheater (SH)	Creep
25	SH outlet header	Creep, fatigue
25	Burners and throats	Overheating, fatigue
30	Reheater	Creep
35	Primary economizer	Corrosion
40	Lower furnace	Overheating, corrosion

Note: The actual component life is highly variable depending on specific design, operation, maintenance, and fuel.

Based on Black & Veatch's Phase I review of Xcel Energy's boiler O&M program, expected major component inspections, maintenance and replacements have been completed or are planned in accordance with accepted boiler OEM recommendations and industry practices. This includes planned replacement of Finishing Superheater Pendant sections and a large waterwall section due to quench cracking in 2017, and planned replacement of the Couton Bottom and Reheater Superheater Pendant due to ash erosion in 2020. These planned maintenance actions demonstrate Xcel Energy's foresight into boiler life and maintenance. Based on our review, Sherco 3's boiler appears to be aging as expected for a boiler commissioned in 1987. Given the continued investment noted, continued operation in a manner similar to historical the boiler should maintain but not significantly exceed, the average designed life expectancy of a typical steam generator of this size and type..

2.2.2 Turbine Discussion

Most failure mechanisms for turbine/generators are physical degradation of components due to operational conditions combined with component features like design, materials, temperature, looseness and fretting of generator components, solid particle erosion, steam erosion and water erosion. This is what typically drives end of life for turbine/generator components.

Based on the condition assessment information provided and the summary description of the work completed in the restoration project, the Sherco unit 3 turbine is generally in acceptable condition for a unit that was commissioned in 1987. The HP and IP turbines have experienced solid particle erosion. The IP turbine rotor has experienced some bowing. The HP and IP turbine rotors were replaced in 2011 as part of a targeted uprate to improve the operating efficiency of the steam turbine train.

[2] Babcock & Wilcox, "Steam, its generation and use," 40th Edition, 46-4, 1992

Based on Black & Veatch's Phase I review of Xcel Energy's turbine/generator O&M program and the restoration efforts initiated following the 2011 event, maintenance and component replacements have been completed in accordance with accepted turbine/generator O&M practices.

Based on this summary review and despite the extensive work completed during the restoration project, the current condition of the Sherco 3 turbine/generator does not support a significant extension of the unit life past the original design life expectancy.

2.3 ENGINEERING CONSIDERATIONS

Analysis of steam plant lives should include consideration of engineering design life. When a new plant is initially placed in service, its expected life should equal its engineering life. As a unit ages, it is reasonable to reevaluate life span by considering the condition of the plant components, actual plant use and experience, additional capital expenditures, and potential environmental costs and risks. The following sections discuss design life, the major components of steam plants, and factors that lead to component failure and ultimately influence plant life.

2.3.1 Steam Turbines

Based on discussions with the major Original Equipment Manufacturers (OEM) regarding their turbine generator design, it is apparent that expected life and operation is normally specified by the number of starts and shutdowns. These criteria are used by the manufacturer to check design life and to define startup and shutdown procedures today as they were 40 years ago. With proper maintenance, and when operated according to the OEM's recommendations and expectations, a steam turbine can be expected to operate longer than the 30 to 35 year life that is typically specified.

It is important to look at the steam turbine and its related equipment as a number of distinct pieces. Within the steam turbine housing there are numerous "components" all of which must be designed to meet the expected operating conditions and perform reliably for at least some portion of the economic life of the turbine generator. That said a number of these components should be expected to be replaced during the life of the unit. Maintenance in the form of repairs and replacement of components is considered routine over the life of the unit with the exception of the turbine rotor and shell.

Typical practice in the utility industry is to perform a major overhaul of steam turbines every 6 to 10 years. This frequency is considered reasonable and allows for inspection and repair on a frequency that typically will allow for reliable operation for the life of the plant.

2.3.2 Boilers

As is the case with turbines, Black & Veatch's experience with boiler manufacturers has demonstrated that the expected or design life of major boiler components is determined by various factors. The actual age of a piece of equipment is not the primary determining factor, rather the condition practice of use, specific design, fuel quality, water quality and chemistry, capital expenditures, and maintenance procedures determine the expected useful life. In their reference manual "Combustion, Fossil Power" ABB-CE states, "The parameters that affect the life of a

component are the local values of stress and temperature, and its material properties. Life does not only depend on these parameters, it is extremely sensitive to them."[3]

Babcock and Wilcox's "Steam" states, "high temperature creep rupture and creep fatigue failure are the two main aging mechanisms in the high temperature components of high temperature boilers. All components that operate above 900° F are subject to some degree of creep. As a result, most of the components have a finite design life and can fail after 20 to 40 years of operation."

Over the course of the turbine and boiler normal operating life, a utility expects to replace various components of these systems merely in order to maintain the usefulness of the asset. The timing of these replacements is based on failure mechanisms, the original design, the operating regime, fuel (boiler systems), and the maintenance practices.

[3] Combustion Engineering, "Combustion Fossil Power," 4th Edition, 24-9, 1991

3.0 Conclusions

As discussed earlier the end of the useful life of a typical generating plant is a function of the engineering/physical characteristics of the plant and the economic considerations. That useful life drives the evaluation of the expected life of the plant. With respect to the engineering/physical life of the plant the evaluation considers the design, the utilization, maintenance practices and the continuing investment. This life is also influenced by economics of the utilization. That includes the maintenance and capital investment from the owner's perspective but also the costs of operation and the value derived from the utilization. As compliance with regulatory requirements becomes more expensive this will tend to reduce the life as alternatives eventually become more attractive.

In the case of Sherco Unit 3, the information provided indicates that Xcel Energy has maintained the major plant systems in a manner consistent with industry practice and OEM recommendations, especially with respect to the two major plant systems, the boiler and the turbine/generator. The recent restoration effort is intended to bring the unit back to the condition immediately before the accident occurred. There was no specific program to extend the life of the systems beyond the original design. At the same time the utilization of the turbine generator can only be accomplished through the use of the boiler. These two major systems comprise the primary (and most expensive) elements of the generating plant. The information provided indicates the boiler is being maintained in a prudent manner consistent with industry practice and OEM recommendations. Xcel Energy has made prudent capital investments in the boiler systems and has plans to continue in order to maintain the asset. However there is no reason to believe that the asset management program for either the boiler or the turbine will result in a significant increase in the useful life of the plant beyond what is currently projected. In fact there are external drivers, the most specific being potential and already enacted environmental compliance requirements, which will likely reduce or at least limit the economic life of the generating plant.

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☐ **Public Document – Not Public Data Has Been Excised**
☒ **Public Document**

Xcel Energy Information Request No. 4
Docket No.: E002,G002/D-19-161
Response To: MN Department of Commerce
Requestor: Gemma Miltich
Date Received: February 28, 2019

Question:
Reference(s): Page 7 of Xcel's Petition

a. Please provide the (1) total planned capital investments and (2) capital investments incurred to date for the overhaul projects for Angus Anson Units 2 and 3.

b. Does the approximate decrease in annual depreciation expense of $1.5 million take into consideration the investment amounts to be capitalized for Angus Anson Units 2 and 3 (see Petition page 5, Table 1, Angus Anson Units 2&3)?

c. Please provide the manufacturer information or engineering study that supports the 15 year life extension beyond the existing 22 years of remaining life as of January 1, 2019 for Angus Anson Units 2 and 3.

Response:

a. 1) The planned capital investment for Angus Anson Units 2 and 3 is $20.8M from 2019 thru 2023. The capital project schedule is subject to change based on unit operation and yearly budget reviews.

   2) Please see Attachment A to this response. In summary, Units 2&3 investments from January 2014 to February 2019 for overhaul projects totaled $5.992M.

b. No, the $1.5 million decrease to depreciation is based on plant balances as of January 1, 2019, as can be seen on Attachment B to the Petition. The Company anticipates capitalizing $8.6 million in 2019, which will increase depreciation expense by approximately $0.3 million in 2019 using the proposed remaining life and net salvage. This increase due to plant additions would mitigate the decrease due to the proposed life extension.

Exhibit 3

c. OEM (Siemens) recommendations are based on equivalent starts (ES):
    - 400 ES perform a Combustion Inspection (CI)
    - 800 ES perform a Hot Gas Path (HGP)
    - 1200 ES perform a CI
    - 1600 ES perform Major Inspection
    - 2000 ES perform CI
    - 2400 ES perform a Hot Gas Path (HGP)
    - 2800 ES perform CI
    - 3200 ES perform Major Inspection
    - 3600 ES perform CI
    - 4000 ES perform a Hot Gas Path (HGP)
    - 4400 ES perform CI
    - 4800 ES perform Major Inspection
    - 6400 end of life

Currently, Angus Anson 2 & 3 Equivalent Starts (ES) are at 3000 and 3200 respectively.

Xcel Energy uses an operations model to predict the number of starts for the next five years. The tool we use is Plexos. For the next five years the model predicts an average of 8.4 starts per year. Based on the data from Plexos and extrapolating outlying years Angus Anson 2 & 3 can be extended by 15 years.

Preparer:	Tim Brown	Mary Ohland
Title:	Manager, Sr. Operations	Financial Consultant
Department:	Angus Anson	Energy Supply Finance
Telephone:	605-331-1230	612-330-1920
Date:	March 11, 2019	

	Angus Anson Capital Spend 2014-YTD 2019						
	2014	2015	2016	2017	2018	YTD Feb 2019	Total 5+ Yr Spend
Angus Anson Major OH - Unit 2&3	$ -	$ -	$ -	$ 1,665,310.04	$ 4,326,763.80	$ 415,669.33	$ 5,992,073.84
Angus Anson Total All other Capital Work	$ 1,233,303.22	$ 1,703,132.97	$ 977,536.73	$ 206,754.67	$ 1,520,384.62	$ 29,914.00	$ 5,641,112.21
Angus Anson Total Capital Work	$ 1,233,303.22	$ 1,703,132.97	$ 977,536.73	$ 1,872,064.71	$ 5,847,148.42	$ 445,583.33	$ 11,633,186.05

Exhibit 3

2014

Angus Plant

Parent Proj Full Desc	Current Month				Year-to-Date				Year End			
	Actual	Budget	Variance	Var %	Actual	Budget	Variance	Var %	Forecast	Budget	Variance	Var %
11215836 - ANSC0 2014 Misc Tools and Equi	0	0	0	0. %	10,688	15,000	(4,312)	-29. %	10,688	15,000	(4,312)	-29. %
11485394 - ANSC0 U2-3 Control Sys Upgrade	13,991	0	13,991	100. %	359,032	300,000	59,032	20. %	359,032	300,000	59,032	20. %
11485395 - ANSC0 U2-3 Volt Reg Requiremen	0	0	0	0. %	26,206	0	26,206	100. %	26,206	0	26,206	100. %
11485536 - ANSC0 U2-3 Battery Replacement	11,839	0	11,839	100. %	121,501	85,000	36,501	43. %	121,501	85,000	36,501	43. %
11632397 - ANS0-C-Replace Admin Bldg Blr	0	0	0	0. %	0	105,000	(105,000)	-100. %	0	105,000	(105,000)	-100. %
11764384 - ANS2C UNIT 2 CEMS REPLACEMENT	0	0	0	0. %	211,434	187,972	23,462	12. %	211,434	187,972	23,462	12. %
11764407 - ANS3C UNIT 3 CEMS REPLACEMENT	0	0	0	0. %	216,278	187,972	28,306	15. %	216,278	187,972	28,306	15. %
11764415 - ANS4C UNIT 4 CEMS REPLACEMENT	0	0	0	0. %	65,688	75,997	(10,309)	-14. %	65,688	75,997	(10,309)	-14. %
11863890 - ANSC3 EMER U3 NEW TURNING GEAR	0	0	0	0. %	172,848	0	172,848	100. %	172,848	0	172,848	100. %
11896339 - ANS2-3C Synchroclosure Relays	0	0	0	0. %	18,891	0	18,891	100. %	18,891	0	18,891	100. %
11913023 - ANS4C CT Heaters	0	0	0	0. %	10,146	0	10,146	100. %	10,146	0	10,146	100. %
12005989 - ANS0C REPLACE VARIABLE FREQ DR	0	0	0	0. %	10,906	0	10,906	100. %	10,906	0	10,906	100. %
12015996 - ANS0C Humidity Sensor Replacem	51	0	51	100. %	9,686	0	9,686	100. %	9,686	0	9,686	100. %
Total	**25,880**	**0**	**25,880**	**100. %**	**1,233,303**	**956,941**	**276,362**	**29. %**	**1,233,303**	**956,941**	**276,362**	**29. %**

Exhibit 3

2015

Angus Plant

Parent Proj Full Desc	Current Month				Year-to-Date				Year End			
	Actual	Budget	Variance	Var %	Actual	Budget	Variance	Var %	Forecast	Budget	Variance	Var %
11338381 - ANS 0C 2015 Tools and Equip Ca	4,086	7,500	(3,414)	-46. %	14,970	15,000	(30)	0. %	14,970	15,000	(30)	0. %
11485394 - ANSC0 U2-3 Control Sys Upgrade	(169)	0	(169)	100. %	1,287,511	1,230,157	57,354	5. %	1,287,511	1,230,157	57,354	5. %
11485536 - ANSC0 U2-3 Battery Replacement	0	0	0	0. %	2,247	0	2,247	100. %	2,247	0	2,247	100. %
12015996 - ANS0C Humidity Sensor Replacem	0	0	0	0. %	(1)	0	(1)	100. %	(1)	0	(1)	100. %
12038505 - ANS0C-Replace Admin Bldg Blr R	194,434	0	194,434	100. %	197,576	0	197,576	100. %	197,576	0	197,576	100. %
12076436 - ANS0C U2&3 CT Eccentricity Mon	0	0	0	0. %	33,606	0	33,606	100. %	33,606	0	33,606	100. %
12076451 - ANS0C Small Project Routine	8,987	0	8,987	100. %	39,737	0	39,737	100. %	39,737	0	39,737	100. %
12076854 - ANS0C -19898 RTU Replacement	1,068	0	1,068	100. %	121,787	0	121,787	100. %	121,787	0	121,787	100. %
12174538 - ANS0C 1 MW Bat CNT Board Rpl	442	0	442	100. %	5,700	0	5,700	100. %	5,700	0	5,700	100. %
241372 - ES Angus Anson 0 FERC 552	0	0	0	0. %	0	0	0	0. %	0	0	0	0. %
241373 - ES Angus Anson 0 FERC 553	0	0	0	0. %	0	0	0	0. %	0	0	0	0. %
Total	**208,848**	**7,500**	**201,348**	**2685. %**	**1,703,133**	**1,245,157**	**457,976**	**37. %**	**1,703,133**	**1,245,157**	**457,976**	**37. %**

Exhibit 3

2016

Angus Plant

								YTD DEC 2016				YE 2016			
WBS Element (0COORDER 0WBS ELEMT) - Project Definition (Text)	WBS Level 2	WBS Element - Medium Text	Actual DEC-2016	Budget DEC-2016	Variance(Act-Bud)	Forecst DEC-2016	Variance(Act-Fcst)	Actual YTD	Budget YTD	YTD Variance(Act-Bud)	YE Forecast	YE Budget	YE Variance(Fcst-Bud)	YE Prev mth Forecast	YE Variance(CM Fcst-Prev mth Fcst)
ANS_Angus Anson	A.0001571 010	Evergreen U2-3 Control Systems Upgr						1,117		1,117	1,117		1,117	1,117	0
	A.0001571 016	ANS4C GSU Transformer Rplcmnt-21528	(32,188)		-32187.65		(32,188)	878,496		878,496	878,496		878,496	910,684	(32,188)
	A.0001571 030	ANS0C Emergent -CNT panel - 1 MW battery	4,843		4842.79		4,843	4,843		4,843	4,843		4,843		4,843
	A.0001571 032	ANS2C Emergent -Ignitor assemblies	55,068		55068.07		55,068	55,068		55,068	55,068		55,068		55,068
	A.0001571 033	ANS0C Emergent -VFD Replacement	7,862		7861.98		7,862	7,862		7,862	7,862		7,862		7,862
	A.0001571 035	ANS0C Emergent - Firewall PC Rplc	3,003		3003.18		3,003	3,003		3,003	3,003		3,003		3,003
	A.0001571 039	Replace Roof						(2,129)		(2,129)	(2,129)		(2,129)	(2,129)	0
	A.0001571 041	ANS0C Sm Prj VFD Replc	6,176		6176.46		6,176	6,176		6,176	6,176		6,176		6,176
	A.0001571 041	ANS4C Sm Prj Rplc battery chrgr	11,069		11068 8		11,069	11,069		11,069	11,069		11,069		11,069
	A.0001571 041	ANS4C Sm Prj Rplc compressor	12,032		12031.56		12,032	12,032		12,032	12,032		12,032		12,032
	A.0001571 041	BUDG-ANS0C Small Project Routine							30,000	(30,000)		30,000	(30,000)		
ANS_Angus Anson			67,865		67865.19		67,865	977,537	30,000	947,537	977,537	30,000	947,537	909,672	67,865

Exhibit 3

2017

Angus Anson

WBS Level 2	WBS Element - Medium Text	Legacy Parent WO	DEC 2017					YTD DEC 2017					YE 2017		
			Actual DEC-2017	Forecst DEC 2017	Variance(Act-Fcst)	Budget DEC-2017	Variance(Act-Bud)	Actual YTD	Budget YTD	YTD Variance(Act-Bud)	YE Forecast	YE Prev mth Forecast	YE Budget	Variance(Act-Fcst)	YE Variance(Fcst-Bud)
A.0001591 002	ANS3C U3 Major Overhaul	11485603	(37,287)		-37286.57		(37,287)	(2,490)		(2,490)	(2,490)	34,797		(37,287)	(2,490)
A.0001591 002	BUDG-ANSC3 U3 Major Overhaul	11485603		1503000	-1503000							1,503,000		(1,503,000)	
Total		**Sum**	**(37,287)**	**1503000**	**(1,540,287)**		**(37,287)**	**(2,490)**		**(2,490)**	**(2,490)**	**1,537,797**		**(1,540,287)**	**(2,490)**

Angus Anson Major Overhaul

WBS Level 2	WBS Element - Medium Text	Legacy Parent WO	DEC 2017					YTD DEC 2017					YE 2017		
			Actual DEC-2017	Forecst DEC 2017	Variance(Act-Fcst)	Budget DEC-2017	Variance(Act-Bud)	Actual YTD	Budget YTD	YTD Variance(Act-Bud)	YE Forecast	YE Prev mth Forecast	YE Budget	Variance(Act-Fcst)	YE Variance(Fcst-Bud)
A.0001716 001	ANS3C U3 Major Overhaul	#	34,731		34730.79		34,731	34,731		34,731	34,731			34,731	34,731
A.0001716 001	CW P External Labor	#	1,633,069		1633069.21		1,633,069	1,633,069		1,633,069	1,633,069			1,633,069	1,633,069
Total		**Sum**	**1,667,800**		**1,667,800**		**1,667,800**	**1,667,800**		**1,667,800**	**1,667,800**			**1,667,800**	**1,667,800**

1,630,513 1,665,310

ANS Angus Anson

WBS Level 2	WBS Element - Medium Text	Legacy Parent WO	DEC 2017					YTD DEC 2017					YE 2017		
			Actual DEC-2017	Forecst DEC 2017	Variance(Act-Fcst)	Budget DEC-2017	Variance(Act-Bud)	Actual YTD	Budget YTD	YTD Variance(Act-Bud)	YE Forecast	YE Prev mth Forecast	YE Budget	Variance(Act-Fcst)	YE Variance(Fcst-Bud)
A.0001571 016	ANS4C GSU Transformer Rplcmnt-2	34004470						(37)		(37)	(37)	(37)			(37)
A.0001571 028	ANS0C Emergent CEMs server upgr	#						13,952		13,952	13,952	13,952			13,952
A.0001571 030	ANS0C Emergent -CNT panel - 1 MV	#						0		0	0	0			0
A.0001571 032	ANS2C Emergent -Ignitor assemblie	#						0		0	0	0			0
A.0001571 033	ANS0C Emergent -VFD Replacemer	#						0		0	0	0			0
A.0001571 035	ANS0C Emergent - Firewall PC Rplc	#						18,775		18,775	18,775	18,775			18,775
A.0001571 041	ANS0C Sm Prj VFD Replc	12076460						0		0	0	0			0
A.0001571 041	ANS4C Sm Prj Rplc battery chrgr	12076460						0		0	0	0			0
A.0001571 041	ANS4C Sm Prj Rplc compressor	12076460						0		0	0	0			0
A.0001571 042	BUDG-ANS0C Small Project Routine	12076461				2,500	(2,500)		30,000	(30,000)			30,000		(30,000)
A.0001571 049	ANS0C Hwy 100 land sale project	34007715						(744,759)		(744,759)	(744,759)	(744,759)			(744,759)
A.0001571 050	ANS0C ANS Brandon watr towr land	#	659	1000	-340.83		659	(52,038)		(52,038)	(52,038)	(51,698)		(341)	(52,038)
A.0001571 051	ANS4C U4 Replace Comp EGVs - S	#	2,064		2064.26		2,064	5,405		5,405	5,405	3,341		2,064	5,405
A.0001571 051	CW P Materials-External Labor	#	536,931		536931.15		536,931	536,931		536,931	536,931			536,931	536,931
A.0001571 053	BUDG ANS3C U3 Generater Inspec	#		176400	-176400							176,400		(176,400)	
A.0001571 053	CW P External Labor	#	188,161		188160.59		188,161	188,161		188,161	188,161			188,161	188,161
A.0001571 500	ANS00 Ovation Antivirus	#	32		32.42		32	4,606		4,606	4,606	4,574		32	4,606
A.0001571 500	ANS00 Ovation Antivirus CWIP	#	10,836		10836.25		10,836	25,978		25,978	25,978	15,142		10,836	25,978
A.0001571 500	ANS0C Emerg Air Comp Replc	#						15,163		15,163	15,163	15,163			15,163
A.0001571 500	ANS0C Emergent Frame Relay Rplc	#		1	-1			3,860		3,860	3,860	3,861		(1)	3,860
A.0001571 500	ANS0C Emerg VFD Replace	#		1	-1			11,116		11,116	11,116	11,117		(1)	11,116
A.0001571 500	ANS0C Rplc Domestic Well VFD	#	0	2601	-2601		0	10,116		10,116	10,116	12,717		(2,601)	10,116
A.0001571 500	ANS0C Rplc Heaters Fuel Frwding/C	#	3,980	1500	2479.82		3,980	8,673		8,673	8,673	6,193		2,480	8,673
A.0001571 500	ANS2C Emerg CT2 Replc HVAC	#	3,455	1	3453.64		3,455	12,416		12,416	12,416	8,962		3,454	12,416
A.0001571 500	ANS2C Gas detect syst replc	#	(15,954)	1	-15955.33		(15,954)	44,228		44,228	44,228	60,183		(15,955)	44,228
A.0001571 500	ANS2C Rplc CT2 HVAC Unit	#	5,267	4501	765.63		5,267	13,519		13,519	13,519	12,753		766	13,519
A.0001571 500	ANS3C Gas Detection Sys Rplc	#	45,495	41000	4494.6		45,495	45,495		45,495	45,495	41,000		4,495	45,495
A.0001571 500	ANS3C Rplc CT3 HVAC Units	#	10,120	6501	3619.44		10,120	26,625		26,625	26,625	23,005		3,619	26,625
A.0001571 500	ANS MPLS CW P Direct Cost	#						10,990		10,990	10,990	10,990			10,990
A.0001571 500	ANS MPLS CW P NSP Labor Costs	#						7,582		7,582	7,582	7,582			7,582
Total		**Sum**	**791,046**	**233507**	**557,539**	**2,500**	**788,546**	**206,755**	**30,000**	**176,755**	**206,755**	**(350,784)**	**30,000**	**557,539**	**176,755**

1,872,065

Exhibit 3

2018

Angus Anson

WBS Level 2	WBS Element - Medium Text	Legacy Parent WO	DEC 2018					YTD DEC 2018					YE 2018		
			Actual DEC-2018	Forecst DEC 2018	Variance(Act Fcst)	Budget DEC-2018	Variance(Act Bud)	Actual YTD	Budget YTD	YTD Variance(Act Bud)	YE Forecast	YE Prev mth Forecast	YE Budget	Variance(Act Fcst)	YE Variance(Fcst-Bud)
A.0001591.002	ANS3C U3 Major Overhaul	11485603						8,221		8,221	8,221	8,221			8,221
Total		**Sum:**						**8,221**		**8,221**	**8,221**	**8,221**			**8,221**

Angus Anson Major Overhaul

WBS Level 2	WBS Element - Medium Text	Legacy Parent WO	DEC 2018					YTD DEC 2018					YE 2018		
			Actual DEC-2018	Forecst DEC 2018	Variance(Act Fcst)	Budget DEC-2018	Variance(Act Bud)	Actual YTD	Budget YTD	YTD Variance(Act Bud)	YE Forecast	YE Prev mth Forecast	YE Budget	Variance(Act Fcst)	YE Variance(Fcst-Bud)
A.0001716.001	ANS3C U3 Major Overhaul	#	31,282		31281.93		31,282	228,364		228,364	228,364	197,082		31,282	228,364
A.0001716.001	BUDG ANS3C U3 Major Overhaul	#		849410	-849410	950,000	(950,000)		6,000,000	(6,000,000)		849,410	6,000,000	(849,410)	(6,000,000)
A.0001716.001	CWIP External Labor	#	1,338,282		1338281.6		1,338,282	3,718,373		3,718,373	3,718,373	2,380,091		1,338,282	3,718,373
A.0001716.001	Internal Labor RWIP	#	6,035		6034.9		6,035	371,807		371,807	371,807	365,772		6,035	371,807
Total		**Sum:**	**1,375,598**	**849410**		**950,000**	**425,598**	**4,318,543**	**6,000,000**	**(1,681,457)**	**4,318,543**	**3,792,355**	**6,000,000**	**526,188**	**(1,681,457)**

4,326,764

ANS_Angus Anson

WBS Level 2	WBS Element - Medium Text	Legacy Parent WO	DEC 2018					YTD DEC 2018					YE 2018		
			Actual DEC-2018	Forecst DEC 2018	Variance(Act Fcst)	Budget DEC-2018	Variance(Act Bud)	Actual YTD	Budget YTD	YTD Variance(Act Bud)	YE Forecast	YE Prev mth Forecast	YE Budget	Variance(Act Fcst)	YE Variance(Fcst-Bud)
A.0001571.016	ANS4C GSU Transformer Rplcmnt-21	34004470						0		0	0	0			0
A.0001571.028	ANS0C Emergent CEMs server upgra	#						0		0	0	0			0
A.0001571.035	ANS0C Emergent - Firewall PC Rplc	#						0		0	0	0			0
A.0001571.050	ANS0C ANS Brandon watr towr land s	#						460	2,100	(1,640)	460	460	2,100		(1,640)
A.0001571.051	ANS4C U4 Replace Comp EGVs - S1	#						29,107		29,107	29,107	29,107			29,107
A.0001571.051	Bud-ANS4C U4 Replace Comp EGVs	#							780,000	(780,000)			780,000		(780,000)
A.0001571.051	CWIP Materials-External Labor	#						695,852		695,852	695,852	695,852			695,852
A.0001571.051	CWIP NSP Labor	#	(347)		-347.22		(347)	140,560		140,560	140,560	140,907		(347)	140,560
A.0001571.051	RWIP NSP Labor	#						19,659		19,659	19,659	19,659			19,659
A.0001571.052	Bud-ANS0C-Split Rock L1 Relay Repl	#							33,440	(33,440)			33,440		(33,440)
A.0001571.053	ANS3C U3 Generater Inspection	#	1,506		1506.05		1,506	10,827		10,827	10,827	9,321		1,506	10,827
A.0001571.053	BUDG ANS3C U3 Generater Inspectio	#		6170	-6170	50,000	(50,000)		628,000	(628,000)		6,170	628,000	(6,170)	(628,000)
A.0001571.053	CWIP External Labor	#						417,359		417,359	417,359	417,359			417,359
A.0001571.053	CWIP Materials	#	51,026		51026.05		51,026	62,459		62,459	62,459	11,433		51,026	62,459
A.0001571.054	ANS0C Gasline Remote Monitoring U	#						6,968		6,968	6,968	6,968			6,968
A.0001571.500	ANS00 Ovation Antivirus	#						4,987		4,987	4,987	4,987			4,987
A.0001571.500	ANS00 Ovation Antivirus CWIP	#						6,273		6,273	6,273	6,273			6,273
A.0001571.500	ANS0C Emerg Air Comp Replc	#						0		0	0	0			0
A.0001571.500	ANS0C Emerg Sys 1 Upgrade	#	0		0		0	27,340		27,340	27,340	27,340		0	27,340
A.0001571.500	ANS0C Emerg VFD 2018 Replace	#						9,843		9,843	9,843	9,843			9,843
A.0001571.500	ANS0C Emerg VFD Replace	#						0		0	0	0			0
A.0001571.500	ANS0C Emg Acid Vlv Replc	#						4,651		4,651	4,651	4,651			4,651
A.0001571.500	ANS0C Rplc Domestic Well VFD	#						0		0	0	0			0
A.0001571.500	ANS2C Emerg CT2 Replc HVAC	#						3,007		3,007	3,007	3,007			3,007
A.0001571.500	ANS2C Gas detect syst replc	#						0		0	0	0			0
A.0001571.500	ANS2C Rplc CT2 HVAC Unit	#						0		0	0	0			0
A.0001571.500	ANS3C Gas Detection Sys Rplc	#						1,599		1,599	1,599	1,599			1,599
A.0001571.500	ANS3C Rplc CT3 HVAC Units	#						0		0	0	0			0
A.0001571.500	ANS4C Emerg 416KV brkr rplc	#	48,735		48735.24		48,735	51,874		51,874	51,874	3,139		48,735	51,874
A.0001571.500	ANS4C Emerg LCI Pwr Supply Rplc	#						11,386		11,386	11,386	11,386			11,386
A.0001571.500	ANSC Ladder Swing Gates 2018	#						16,171		16,171	16,171	16,171			16,171
A.0001571.500	ANS MPLS CWIP Direct Cost	#						0		0	0	0			0
A.0001571.500	ANS MPLS CWIP NSP Labor Costs	#						0		0	0	0			0
A.0001571.500	BUDG ANS Emergent Fund -Other pr	#		51000	-51000	100	(100)		45,334	(45,334)		51,000	45,334	(51,000)	(45,334)
Total		**Sum:**	**100,920**	**57170**		**50,100**	**50,820**	**1,520,385**	**1,488,874**	**31,511**	**1,520,385**	**1,476,635**	**1,488,874**	**43,750**	**31,511**

Exhibit 3

NSPM Capital Results
February 2019 results as of 3.7.2019
Day 5

January Forecast=Budget
February 2019 Forecast=Forecast

Wind/Non Wind	Plant	SAPWBSLevel2	SAPWBSLevel2Desc	Sum of Feb Act	Sum of Feb Fc	Sum of Act/Fcst	Sum of Feb	Sum of Act/Budg Var	Sum of YTD	Sum of YTD Fcst	Sum of YTD	Sum of YTD	Sum of YTD Act/YTD Budg	Sum of YE Fcst	Sum of YE Budget	Sum of YE Fcst to YE
Base	ANS_Angus Anson	A.0001571.052	ANS0C-ANS0-Split Rock L1 Relay Replace	(12,252)	50,000	(62,252)	60,000	(72,252)	604	62,856	(62,252)	60,000	(59,396)	312,856	300,000	12,856
		A.0001571.053	ANS3C U3 Generater Inspection	15,334	5,610	9,724	5,610	9,724	28,691	18,967	9,724	6,120	22,571	114,767	101,920	12,847
		A.0001571.500	ANS4C Emerg 4.16KV brkr rplc	(0)	-	(0)	-	(0)	619	619	(0)	-	619	619	-	619
Major/Base	ANS_Angus Anson	A.0001716.001	ANS3C U3 Major Overhaul	220,379	181,833	38,546	260,687	(40,308)	415,669	377,123	38,546	474,207	(58,537)	2,344,888	2,134,258	210,630
				223,461	237,443	(13,982)	326,297	(102,836)	445,583	459,565	(13,982)	540,327	(94,744)	2,773,130	2,536,178	236,952

Exhibit 3

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Xcel Energy Information Request No. 5
Docket No.: E002,G002/D-19-161
Response To: MN Department of Commerce
Requestor: Gemma Miltich
Date Received: February 28, 2019

Question:
Reference(s): Page 7 of Xcel's Petition

a. Please provide the manufacturer information or engineering study, demonstrating that the useful life of Angus Anson Unit 4 can be extended by 10 years.

b. What amount, if any, in capital additions by year are expected or planned for Angus Anson Unit 4 to increase the Unit's useful life as proposed?

On page 7 of the Petition, in reference to Angus Anson Unit 4, the Company states that a "revised estimation of the number of peaking plant unit starts and hours" supports the proposal to extend the useful life of the asset. Regarding this estimation of peaking plan unit starts and hours:

c. Please provide the source of the data for this estimation.

d. How have the plant unit "starts and hours" changed to support a 10 year asset life extension?

Response:

a. The following are OEM (General Electric) overhaul recommendations based on Equivalent Starts (ES):

450 ES Combustion Inspection
900 ES for 1st Hot Gas
1350 ES for Combustion Inspection
1800 ES for 1st Major

Currently, Angus Anson 4 has 800 Equivalent Starts

Xcel uses an operations model to predict the number of starts for the next five years. The tool we use is Plexos. For the next five years the model predicts an

Exhibit 4

average of 37 starts per year. Based on the data from Plexos and extrapolating outlying years Angus Anson 4 can be extended by 10 years.

b. The Company anticipates approximately $0.1 million and $3.2 million in capital additions to Angus Anson Unit 4 in 2021 and 2022, respectively. Additions in 2019, 2020, and 2023 are minimal, and we do not have a forecast for 2024 and beyond. However, plant operations drive the proposed life extensions rather than capital additions.

c. Historical starts:

2005 – 158
2006 – 73
2007 – 76
2008 – 57
2009 – 20
2010 – 41
2011 – 33
2012 – 48
2013 – 27
2014 – 22
2015 – 49
2016 – 27
2017 – 44
2018 – 70

As stated above, for the next five years the average starts per year based on Plexos is 37. Outlying years were estimated by extrapolating the data.

d. See our response to part C above.

Preparer:	Tim Brown
Title:	Manager, Sr. Operations
Department:	Angus Anson
Telephone:	605-331-1230
Date:	March 11, 2019

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Xcel Energy Information Request No. 7
Docket No.: E002,G002/D-19-161
Response To: MN Department of Commerce
Requestor: Gemma Miltich
Date Received: February 28, 2019

Question:
Reference(s): Page 8 of Xcel's Petition

a. Please provide an engineering study or other appropriate analysis, demonstrating that the useful lives of Blue Lake Units 1-4 can be extended by 4 years.

b. If the proposed increase in useful life is granted, will Blue Lake Units 1-4 continue to be accredited with MISO through the end of their proposed useful lives?

Response:

a. OEM ASEA Brown Boveri overhaul recommendations based on Equivalent Starts (ES):
   450 Equivalent Starts for CI
   900 Equivalent Starts for 1st Hot Gas
   1350 Equivalent Starts for CI
   1800 Equivalent Starts for 1st Major

   Current starts for Blue Lake Units 1-4:
   Unit 1 – Total 807 Starts
   Unit 2 – Total 755 Starts
   Unit 3 – Total 847 Starts
   Unit 4 – Total 974 Starts

   Historical starts:
   Unit 1
   2014 – 4
   2015 – 5

Exhibit 5

2016 – 7
2017 – 3
2018 – 1

Unit 2

2014 – 4
2015 – 3
2016 – 8
2017 – 5
2018 - 2

Unit 3

2014 – 5
2015 – 2
2016 – 5
2017 – 5
2018 - 6

Unit 4

2014 – 6
2015 – 3
2016 – 4
2017 – 5
2018 - 5

Operation Model predictive tool (Plexos) starts:

Unit 1

2019 – 0
2020 – 0
2021 – 0
2022 – 0
2023 – 0

Unit 2

2019 – 0
2020 – 0
2021 – 0
2022 – 0
2023 – 0

Unit 3

2019 – 0
2020 – 0
2021 – 0
2022 – 0
2023 - 0

Exhibit 5

Unit 4

2019 – 0
2020 – 0
2021 – 0
2022 – 0
2023 – 0

In 2014 Blue Lake Units 1-4 completed borescope inspections and no urgent findings were identified. With this data, Blue Lake Units 1-4 was extended four years.

b. Yes.

Preparer:	Tim Brown
Title:	Manager, Sr. Operations
Department:	Angus Anson
Telephone:	605-331-1230
Date:	March 11, 2019

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Xcel Energy Information Request No. 8
Docket No.: E002,G002/D-19-161
Response To: MN Department of Commerce
Requestor: Gemma Miltich
Date Received: February 28, 2019

Question:
Reference(s): Pages 8-9 of Xcel's Petition

a. Please provide an engineering study or other appropriate analysis, demonstrating that the useful lives of Blue Lake Units 7 & 8 can be extended by 10 years.

b. What amount, if any, of capital additions (by year) are expected or planned for Blue Lake Units 7 and 8 to increase the Units' useful lives as proposed?

Response:

a. OEM (General Electric) Overhaul recommendations Based on Equivalent Starts (ES)
   450 ES for CI
   900 ES for 1st Hot Gas
   1350 ES for CI
   1800 ES for 1st Major

   Units commissioned in 2005
   Starts to date for Unit 7 and Unit 8 are 622 and 681 respectfully

   Historical Starts:

Unit 7	2005 – 86	2012 - 81
	2006 – 46	2013 – 37
	2007 – 43	2014 – 18
	2008 – 22	2015 – 35
	2009 – 12	2016 – 70
	2010 - 54	2017 – 33
	2011 – 47	2018 – 38

Exhibit 6

Unit 8	2005 – 88	2012 -77
	2006 – 66	2013 – 71
	2007 – 62	2014 – 20
	2008 – 11	2015 – 32
	2009 – 7	2016 – 76
	2010 – 42	2017 – 38
	2011 – 37	2018 – 54

Plexos Model used for 2019 to 2023 Starts-

Unit 7	2019 – 29
	2020 – 32
	2021 – 27
	2022 – 26
	2023 - 24
Unit 8	2019 – 31
	2020 – 31
	2021 – 28
	2022 – 26
	2023 - 28

Xcel Uses an operation model to predict the number of starts for the next five years. For the next five years the average predicted starts per year based on Plexos for Unit 7 is 27.6 starts per year and for Unit 8 is 28.8 starts per year. With this information (predicted starts) and the number of current starts per unit the life. For Unit 7 & 8 were extended 10 years.

b. In the most recent 5 year forecast, the Company anticipates capital additions to Blue Lake Units 7 and 8 as shown in the table below. However, plant operations drive the proposed life extensions rather than capital additions.

Year	Forecasted additions (in millions)
2019	$ 0.1
2020	0.1
2021	5.7
2022	3.8
2023	-
	$ 9.7

Preparer:	Tim Brown
Title:	Manager, Sr. Operations
Department:	Angus Anson
Telephone:	605-331-1230
Date:	March 11, 2019

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Xcel Energy Information Request No. 6
Docket No.: E002,G002/D-19-161
Response To: MN Department of Commerce
Requestor: Gemma Miltich
Date Received: February 28, 2019

Question:
Reference(s): Page 8 of Xcel's Petition

On page 8 of the Petition, in reference to Black Dog Unit 5, the Company states that a "…Unit 5 will not be dismantled until Unit 6 is also retired. This practice can be seen…for several of our other plants including Angus Anson and Blue Lake." Regarding this statement:

a. Please clarify: For the Angus Anson and Blue Lake Units that received similar treatment to that proposed for the Black Dog Units 5 and 6, were the useful lives of inactive Units extended, were the Units dismantled simultaneously with others to save costs, or both?

b. If inactive Angus Anson and Blue Lake Units' useful lives were extended to align with the time of dismantling, by how many years were the useful lives extended for those Units?

c. Please explain if Black Dog Unit 5 will be operating the extra 26.3 years? If not, why is reasonable to extend the deprecation remaining life?

Response:

a. Only the life of FERC Account 341 Structures and Improvements is extended to match the longest-lived unit on site. All other accounts have a life commensurate with the anticipated operational date of that specific unit. This can be mostly clearly seen on pages 4 and 5 of Attachment A to the Petition. Angus Anson Units 2-3 have a proposed 26.4 year on FERC 341 but a 22.0 year life on FERC 342-346. The 26.4 year life agrees to that of Angus Anson Unit 4. Some facilities house two units with different lives in the same building; therefore it would not be practical to dismantle half of the building while one unit continues to operate. By dismantling all structures at the same

Exhibit 7

time, the Company anticipates cost savings. As such, co-located generation units with different lives should depreciate their components to match the operational life of the specific unit but the structures should be depreciated until the longest-lived unit retires.

b. Both Angus Anson Units 2 and 3 and Blue Lake Units 1 through 4 are still operational and are not inactive. Extending the lives of the non-structures and improvement accounts would result in a 4.4 year and 21.9 year extension, respectively. Such an extension would be inappropriate for the non-structures and improvement accounts (such as the generator account) as it would not agree to the operational retirement date, not comply with the matching principal, and would provide intergenerational inequity.

c. No, the plant will not operate the extra 26.3 years. The building housing the structure for Black Dog Unit 5 will simply be dismantled 26.3 years after Unit 5 shuts down in order to be dismantled at the same time as Unit 6's structures. Therefore, it is reasonable only to extend FERC 341 as described in the response to Part A above.

Preparer:	Courtney Young
Title:	Financial Consultant
Department:	Capital Asset Accounting
Telephone:	612-330-5897
Date:	March 11, 2019

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Xcel Energy Information Request No. 4
Docket No.: E002,G002/D-19-161
Response To: MN Office of the Attorney General
Requestor: Ian Dobson
Date Received: February 26, 2019

Question:
For all responses show amounts for Total Company and the Minnesota jurisdictional retail unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.

Reference: Blazing Star I wind farm.

Provide a cost status and updated CAR as mentioned in the January 2019 monthly progress report filed for this wind farm in 16-686.

Provide the actual YTD costs incurred for the Blazing Star I wind farm, and the projected costs for each month from March 2019 through December 2019. Compare these costs to the cap the Company committed to in 16-777.

Provide supporting calculations on how the Company determined the 2019 depreciation expense of $559,266.

Response:
Please see Attachment A for the updated project CAR which includes the project capital costs Spend YTD, March through December 2019 monthly cost projections and capital cost cap comparison.

Please see Attachment B to this response for a calculation of the 2019 depreciation expense for this wind farm. Depreciation is based on the proposed 25 year life and negative 8.5% net salvage rate as requested in this docket.

Please note, Attachment A to this response contains economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by other persons and is subject to efforts by the Company to protect

Exhibit 8

the information from public disclosure. For this reason, we ask that the data be treated as non-public data pursuant to Minn. Stat. § 13.37, subd. 1(b).

Preparer:	Brad Morrison	Courtney Young
Title:	Project E&C Manager	Financial Consultant
Department:	Energy Supply	Capital Asset Accounting
Telephone:	612-330-6283	612-330-5897
Date:	March 8, 2019	

PROTECTED DATA SHADED

Blazing Star I - Cost Analysis Report

	Spend YTD	*Total Project Forecast*	*2016 Total Actuals*	*2017 Total Actuals*	*2018 Total Actuals*	*Mar-19*	*Apr-19*	*May-19*	*Jun-19*	*Jul-19*	*Aug-19*	*Sep-19*	*Oct-19*	*Nov-19*	*Dec-19*	*2019 Total Forecast*	*2020 Total Forecast*
WTG and Balance of Plant																	
Grid Tie Cost, MPT and Collector Sub																	
Network Interconnection and Upgrades																	
Development and Landowner Payments																	
Project Team, consultants, legal, environ, overheads																	
Total																	
16-777 Project CAP																	

NOTE:
1) Excludes AFUDC

Exhibit 8

Blazing Star I Wind Farm

Forecasted Plant In-Service Date		December 2019
Forecasted Plant In-Service Amount	$	309,271,511
Annual depreciation rate (based on proposed 25 year life)		4%
Proposed net salvage percent		-8.50%
Annual net salvage rate (based on proposed -8.5% net salvage)		-0.34%
2019 forecasted depreciation expense	**$**	**559,266**

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Xcel Energy Information Request No. 5
Docket No.: E002,G002/D-19-161
Response To: MN Office of the Attorney General
Requestor: Ian Dobson
Date Received: February 26, 2019

Question:
For all responses show amounts for Total Company and the Minnesota jurisdictional retail unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.

Reference: Foxtail wind farm.

Provide the actual YTD costs incurred for the Foxtail wind farm, and the projected costs for each month from March 2019 through September 2019. Compare these costs to the cap the Company committed to in 16-777.

Provide supporting calculations on how the Company determined the 2019 depreciation expense of $3,229,622.

Response:
Please see Attachment A for a table providing project capital costs Spend YTD, March through September 2019 monthly cost projections and capital cost cap comparison.

Please see Attachment B to this response for a calculation of the 2019 depreciation expense for this wind farm. Depreciation is based on the proposed 25 year life and negative 8.5% net salvage rate as requested in this docket.

Please note, Attachment A to this response contains economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by other persons and is subject to efforts by the Company to protect the information from public disclosure. For this reason, we ask that the data be treated as non-public data pursuant to Minn. Stat. § 13.37, subd. 1(b).

Exhibit 9

PUBLIC DOCUMENT –
NOT PUBLIC DATA HAS BEEN EXCISED

Preparer:	Brad Morrison	Courtney Young
Title:	Project E&C Manager	Financial Consultant
Department:	Energy Supply	Capital Asset Accounting
Telephone:	612-330-6283	612-330-5897
Date:	March 8, 2019	

Xcel Energy

	Spend YTD	Total Project Forecast	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19
Totals									
16-777 Project CAP									

NOTE:
1) Excludes AFUDC

Exhibit 9

Foxtail Wind Farm

Forecasted Plant In-Service Date September 2019

	Forecasted Plant In-Service Amount
Sep-19	$ 250,099,298
Oct-19	$ 5,764,427
Nov-19	$ 1,594,681
Dec-19	$ 1,664,639
	$ 259,123,045

Annual depreciation rate (based on proposed 25 year life)	4%
Proposed net salvage percent	-8.50%
Annual net salvage rate (based on proposed -8.5% net salvage)	-0.34%

	2019 forecasted depreciation expense
Sep-19	$ 452,263
Oct-19	$ 914,950
Nov-19	$ 928,258
Dec-19	$ 934,151
	$ 3,229,622

PUBLIC DOCUMENT –
NOT PUBLIC DATA HAS BEEN EXCISED

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☒ **Public Document – Not Public Data Has Been Excised**
☐ **Public Document**

Xcel Energy Information Request No. 6
Docket No.: E002,G002/D-19-161
Response To: MN Office of the Attorney General
Requestor: Ian Dobson
Date Received: February 26, 2019

Question:
For all responses show amounts for Total Company and the Minnesota jurisdictional retail unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.

Reference: Lake Benton wind farm.

Provide the actual YTD costs incurred for the Lake Benton wind farm, and the projected costs for each month from March 2019 through December 2019. Compare these costs to the cap the Company committed to in 16-777.

Provide supporting calculations on how the Company determined the 2019 depreciation expense of $308,490.

Response:
Please see Attachment A for a table providing project capital costs Spend YTD, March through December 2019 monthly cost projections and capital cost cap comparison.

Please see Attachment B to this response for a calculation of the 2019 depreciation expense for this wind farm. Depreciation is based on the proposed 25 year life and negative 8.5% net salvage rate as requested in this docket.

Please note, Attachment A to this response contains economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by other persons and is subject to efforts by the Company to protect the information from public disclosure. For this reason, we ask that the data be treated as non-public data pursuant to Minn. Stat. § 13.37, subd. 1(b).

Exhibit 10

PUBLIC DOCUMENT –
NOT PUBLIC DATA HAS BEEN EXCISED

Preparer:	Brad Morrison	Courtney Young
Title:	Project E&C Manager	Financial Consultant
Department:	Energy Supply	Capital Asset Accounting
Telephone:	612-330-6283	612-330-5897
Date:	March 8, 2019	

Xcel Energy

	Spend YTD	Total Project Forecast	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
Totals												
16-777 Project CAP												

NOTE:
1) Excludes AFUDC

Exhibit 10

Lake Benton Wind Farm

Forecasted Plant In-Service Date		December 2019
Forecasted Plant In-Service Amount	$	170,593,443
Annual depreciation rate (based on proposed 25 year life)		4%
Proposed net salvage percent		-8.50%
Annual net salvage rate (based on proposed -8.5% net salvage)		-0.34%
2019 forecasted depreciation expense	**$**	**308,490**

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Xcel Energy Information Request No. 2
Docket No.: E002,G002/D-19-161
Response To: MN Office of the Attorney General
Requestor: Ian Dobson
Date Received: February 26, 2019

Question:
For all responses show amounts for Total Company and the Minnesota jurisdictional retail unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.

Reference: Initial Petition.

Confirm that the Company is not requesting to reallocate depreciation reserves between different plants.

If the Company is requesting to reallocate depreciation reserve balances, update Attachment B to include a new column between "Plant Balance 1/1/19" and "Reserve Balance 1/1/19" showing the amount to be transferred in/out.

Response:
We are not requesting a reserve reallocation in this docket.

Preparer: Courtney Young
Title: Financial Consultant
Department: Capital Asset Accounting
Telephone: 612-330-5897
Date: March 8, 2019

Exhibit 11

STATE OF MINNESOTA

OFFICE OF THE ATTORNEY GENERAL

KEITH ELLISON
ATTORNEY GENERAL

SUITE 1400
445 MINNESOTA STREET
ST. PAUL, MN 55101-2131
TELEPHONE: (651) 296-7575

April 22, 2019

Mr. Daniel Wolf, Executive Secretary
Minnesota Public Utilities Commission
121 Seventh Place East, Suite 350
St. Paul, MN 55101-2147

Re: ***In the Matter of the Petition of Northern States Power Company d/b/a Xcel Energy for Approval of the 2019 Review of Remaining Lives.***
MPUC Docket No. E002,G002/D-19-161

Dear Mr. Wolf:

Enclosed and e-filed in the above-referenced matter please find both the PUBLIC and TRADE SECRET Comments of the Minnesota Office of the Attorney General–Residential Utilities and Antitrust Division.

By copy of this letter all parties have been served. An Affidavit of Service is also enclosed.

Sincerely,

s/ **Joseph C. Meyer**
JOSEPH C. MEYER
Assistant Attorney General

(651) 757-1433 (Voice)
(651) 296-9663 (Fax)
joseph.meyer@ag.state.mn.us

Enclosure

AFFIDAVIT OF SERVICE

Re: ***In the Matter of the Petition of Northern States Power Company d/b/a Xcel Energy for Approval of the 2019 Review of Remaining Lives.***
MPUC Docket No. E002,G002/D-19-161

STATE OF MINNESOTA)
) ss.
COUNTY OF RAMSEY)

DEANNA DONNELLY hereby states that on 22nd day of April, 2019, I e-filed with eDockets ***Comments of the Minnesota Office of the Attorney General—Residential Utilities and Antitrust Division, Public and Trade Secret Versions,*** and served the same upon all parties listed on the attached service list by e-mail, and/or United States Mail with postage prepaid, and deposited the same in a U.S. Post Office mail receptacle in the City of St. Paul, Minnesota.

s/ Deanna Donnelly
DEANNA DONNELLY

Subscribed and sworn to before me
this 22nd day of April, 2019.

s/ Patricia Jotblad
Notary Public
My Commission expires: January 31, 2020.

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
David	Aafedt	daafedt@winthrop.com	Winthrop & Weinstine, P.A.	Suite 3500, 225 South Sixth Street Minneapolis, MN 554024629	Electronic Service	No	OFF_SL_19-161_D-19-161
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_19-161_D-19-161
Alison C	Archer	aarcher@misoenergy.org	MISO	2985 Ames Crossing Rd Eagan, MN 55121	Electronic Service	No	OFF_SL_19-161_D-19-161
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John	Coffman	john@johncoffman.net	AARP	871 Tuxedo Blvd. St, Louis, MO 63119-2044	Electronic Service	No	OFF_SL_19-161_D-19-161
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1800 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_19-161_D-19-161
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Ian	Dobson	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_19-161_D-19-161
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Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7 h St E St. Paul, MN 55106	Electronic Service	No	OFF_SL_19-161_D-19-161
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