COMMERCE DEPARTMENT

March 5, 2019 **PUBLIC DOCUMENT**

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101

RE: **PUBLIC Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. IP6949, E002/PA-18-702

Dear Mr. Wolf:

Attached are the PUBLIC comments of the Minnesota Department of Commerce, Division of Energy Resources (Department) in the following matter:

Petition for Approval of the Acquisition of the Mankato Energy Center.

The Petition was filed on November 27, 2018 by:

Aakash H. Chandarana
Regional Vice President, Rates and Regulatory Affairs
Northern States Power Company
414 Nicollet Mall
Minneapolis, MN 55401

The Department recommends that the Minnesota Public Utilities Commission (Commission) **take no action, pending submittal of additional analyses**. The attached comments do not address the site permit transfer request. The Department's team of Nancy Campbell and Steve Rakow is available to answer any questions the Commission may have.

Sincerely,

/s/ STEVE RAKOW
Analyst Coordinator

/s/ NANCY CAMPBELL
Analyst Coordinator

SR/NC/ja
Attachment

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Before the Minnesota Public Utilities Commission

Public Comments of the Minnesota Department of Commerce
Division of Energy Resources

Docket No. IP6949, E002/PA-18-702

I. INTRODUCTION

On November 27, 2018, Northern States Power Company, doing business as Xcel Energy (Xcel, NSPM, or the Company) filed the Company's *Petition for Approval of the Acquisition of the Mankato Energy Center* (Petition) pursuant to Minnesota Statutes § 216B.50. The existing Mankato Energy Center (MEC I) is a 375-MW one-on-one natural gas combined cycle facility that was completed in 2006 by Calpine Corporation. Since that time, MEC I has operated under a 20-year power purchase agreement (PPA) with Xcel.

The Mankato Energy Center expansion project (MEC II) was approved by the Minnesota Public Utilities Commission (Commission) in 2014 in a resource acquisition process stemming from the Company's 2010 integrated resource plan (IRP).[1] In late 2016 Calpine Corporation sold the MEC I facility and MEC II expansion rights to Southern Power Company[2] (Southern). MEC II expands the existing MEC I facility by 345 MW via the addition of a new combustion turbine and heat recovery steam generator resulting in a two-on-one natural gas combined cycle facility. MEC II is scheduled to reach commercial operation by June 2019. The capacity and energy from the MEC II expansion project is committed to Xcel under a second 20-year PPA commencing at the in-service date.

The Company requests that the Commission:

- determine that the proposal to acquire the existing MEC I facility is prudent and in the public interest under Minnesota Statutes § 216B.50;
- approve a fuel clause adjustment (FCA) variance under Minnesota Rules 7829.3200 allowing the Company to recover the difference between the 2019 revenue requirement resulting from the transaction and the revenues already in base rates for the capacity portions of the current MEC I and MEC II PPAs;
- approve the transfer of the site permits for MEC I and MEC II under Minnesota Rules 7850.5000;

[1] Resource plan was Docket No. E002/RP-10-825; resource acquisition was Docket No. E002/CN-12-1240.
[2] Southern Power Company is a wholly-owned affiliate Southern Company.

- issue a notice setting a schedule for comments and reply comments from interested parties on the Petition;
- establish a procedural schedule such that the Commission may issue a written order as close as practicable to June 2019 so Xcel may proceed with the transaction as contemplated by the agreement with Southern; and
- vary its rules, consistent with past practice, with respect to certain filing requirements referenced in Minnesota Rules 7825.1800.

On December 20, 2018 the Commission issued its *Notice of Comment Period* (Notice) indicating that the following topics are open for comment:

1. Is the purchase proposal prudent and in the public interest?
2. What are all the assumptions/inputs used to develop the cost/benefit analysis? Are those assumptions/inputs consistent with Xcel's stated goals to be carbon-free by 2050? Are those assumptions/inputs reasonable?
3. Should Xcel be allowed to recover the difference between the 2019 revenue requirement resulting from the transaction and the revenues already in base rates for the capacity portions of the MEC I and MEC II PPAs?
4. If the transaction is approved, how should cost recovery be effected?
5. If the transaction is approved, will it require any rule variances and, if so, which rules should be varied?
6. If the transaction is approved, how will it impact the 2019 Capital True-Up filing?
7. If the transaction is approved, how will it impact Xcel's capital structure?
8. If the transaction is approved, how do the MEC I and MEC II useful lives fit with Xcel's stated goal to be carbon-free by 2050?
9. If Xcel becomes carbon-free by 2050, should ratepayers be liable for any resulting MEC I and MEC II related stranded costs?
10. Should approval be subject to any conditions and, if so, what should those conditions be?
11. What action should the Commission take regarding the request to transfer the site permit in this docket?
12. Are there other issues or concerns related to this matter?

Below are the comments of the Department regarding the issues raised by the Petition and the Commission's Notice other than the request to approve the site permit transfer.

II. DEPARTMENT ANALYSIS

A. GOVERNING STATUTES AND RULES

1. Applicability of Minnesota Statutes § 216B.50

The Company filed the Petition pursuant to Minnesota Statutes § 216B.50, which states in part:

> No public utility shall sell, acquire, lease, or rent any plant as an operating unit or system in this state for a total consideration in excess of $100,000, or merge or consolidate with another public utility or transmission company operating in this state, without first being authorized so to do by the Commission. … If the Commission finds that the proposed action is consistent with the public interest, it shall give its consent and approval by order in writing. In reaching its determination, the Commission shall take into consideration the reasonable value of the property, plant, or securities to be acquired or disposed of, or merged and consolidated.

Xcel proposed to acquire an operating unit to serve the Company's system for a total consideration in excess of $100,000. Therefore, Minnesota Statutes § 216B.50 applies to the Petition.

2. Decision Criterion

Minnesota Statutes § 216B.50 establishes a single test:

> If the Commission finds that the proposed action is consistent with the public interest, it shall give its consent and approval by order in writing. In reaching its determination, the Commission shall take into consideration the reasonable value of the property, plant, or securities to be acquired or disposed of, or merged and consolidated.

Xcel concluded that the proposed transaction is in the public interest because the transaction:

- will provide cost savings to the Company’s customers;
- is consistent with Xcel’s commitment to achieve 85 percent carbon-free energy by 2030 while maintaining both affordability and reliability; and
- does not materially impact the amount of gas generation in Xcel’s portfolio.

The Department's review of the costs and benefits of the proposed transaction is provided below.

3. Information Requirements

Minnesota Rules 7825.1800, subpart B requires the Company to provide various information set forth in Minnesota Rules 7825.1400 for a property transfer. In the Petition, Xcel requested that the Commission waive application of Minnesota Rules 7825.1800, subp. B. The Company noted that the Commission has previously granted a variance to the requirements to provide the information outlined under Minnesota Rules 7825.1400 (A) to (J) in proposed acquisition of property transactions.

Minnesota Rules 7829.3200 allows the Commission to vary its rules if the Commission finds:

A. enforcement of the rule would impose an excessive burden upon the applicant or others affected by the rule;
B. granting the variance would not adversely affect the public interest; and
C. granting the variance would not conflict with standards imposed by law.

Xcel's analysis of the variance requirements is as follows:

- excessive burden—the proposed transaction does not implicate the information sought by Minnesota Rules 7825.1400 (A) to (J) and, thus, its provision would impose an excessive burden on the Company;
- public interest—because the proposed transaction does not involve the issuance of securities, granting a variance does not conflict with the public interest; and
- standards imposed by law—as evidenced by previous Commission precedent, a waiver will not violate any standards imposed by law.

Since the proposed transaction does not involve the issuance of securities, the Department agrees with Xcel's analysis. Moreover, the Commission requested information about any effects of the proposal on Xcel's capital structure, so any concerns can be addressed there. Therefore, the Department recommends that the Commission approve a variance to Minnesota Rules 7825.1800, subp. B to allow Xcel to not provide the information set forth in Minnesota Rules 7825.1400, items (A) to (J).

B. REVIEW OF COST RECOVERY AND ACCOUNTING ISSUES

1. 2019 Revenue Requirement True-up

On page 39 of the Petition, Xcel noted that the current MEC I and MEC II PPAs include both energy and capacity payments. The energy charge is incurred per MWh used and is recovered through the fuel clause adjustment. The capacity charge is currently recovered through base rates. However, Xcel believes it should recover more since it will need to invest capital in order to close the transaction before filing the next rate case. The Department notes that Xcel has recently confirmed a November 1, 2019 rate case filling.

In the Petition, Xcel requested that the Commission "Approve an FCA variance under Minn. R. 7829.3200 allowing the Company to recover the difference between the 2019 revenue requirement resulting from the transaction and the revenues already in base rates for the capacity portions of the current MEC I and MEC II PPA."

The Company's Attachment H shows what the Company calls Revenue Requirement Under-Recovery After Purchase, which is the difference between what is in base rates for capacity costs for 2019 and Xcel's full revenue requirement for 2019 based on the $650 million purchase price – assuming different dates of ownership for MEC I and MEC II. The Company also showed these calculations for 2020 and 2021, but the 2020 and 2021 calculations are not relevant since Xcel will be filing a rate case about November 1, 2019 with a January 1, 2020 interim rate increase request. The Company calculated the following under-recovery amounts for 2019:

Ownership Date	Under-Recovery
June 1, 2019	$4.20 million
August 1, 2019	$8.49 million
September 1, 2019	$10.62 million

Based on the Department's review, Xcel's request to true-up rate recovery for 2019 revenue requirements for the MEC I and II gas plants outside of a rate case is not reasonable and not consistent with past Minnesota practices for several reasons.

First, in Minnesota Power's Nemadji Trail Energy Center (NTEC) facility filing (Docket Nos. E015/AI-17-568 and E015/RP-15-690), the Department concluded that rate recovery for capacity costs (capital costs) and non-fuel operating and maintenance (O&M) costs should occur through base rates set in a future general rate case, not in a rider as proposed by Minnesota Power. The Department's NTEC testimony also noted that rider recovery for capacity/capital costs and non-fuel O&M costs for a gas plant outside a rate case is not reasonable or permitted under Minnesota law, as provided in Campbell Direct, pages 33 to 35, and Campbell Surrebuttal at pages 33 to 34. The Commission's January 24, 2019 *Order Approving Affiliated-Interest Agreements with Conditions* confirmed this required rate case recovery process (see Ordering Point 3 and the Order's Attachment A, pages 21 and 22).

Second, Xcel continues to be subject to a rate case settlement through December 31, 2019 as provided in Xcel's August 16, 2016 Stipulation of Settlement filed in Docket No. E002/GR-15-826. Therefore, it is not reasonable to allow Xcel a true-up for rate recovery in 2019. As discussed above, Xcel will be filing a rate case about November 1, 2019, with interim rates in effect around January 1, 2020. If the MEC I and MEC II transaction is approved, Xcel will be able to seek rate recovery in its next general rate case, which is likely to incorporate a multi-year rate plan (MYRP), starting in 2020. In Xcel's upcoming rate case, the Department and interested parties will use the Commission's order in this proceeding to ensure that rate recovery related to MEC I and MEC II is reasonable.

Third, Xcel's waiver request to allow a true-up of 2019 revenue requirements (capital costs and O&M costs for the MEC I & MEC II gas plants) through the FCA is not appropriate. Costs and revenues allowed through the FCA are defined in Minnesota Rules 7825.2400 – 7825.2600; the rules do not allow recovery of capacity/capital costs or O&M costs through the FCA.[3] Rider recovery was not allowed in Minnesota Power's Energy*Forward* Resource Package proceeding—specifically, the costs associated with the NTEC gas plant as discussed above.

The Department concludes under this section that:

- a true-up or rider recovery of capacity/capital costs and O&M costs of a gas facility is not allowed by Minnesota law;
- a similar true-up was not allowed for Minnesota Power in Docket Nos. E015/AI-17-568 and E015/RP-15-690;
- Xcel is subject to a rate case settlement through 2019; and
- a waiver to allow capacity/capital costs and O&M costs through the FCA is not appropriate since these are not FCA-eligible costs per Minnesota Rule and Xcel will have an opportunity to request cost recovery in its upcoming rate case.

Thus, the Department recommends that the Commission deny Xcel's request for the rate recovery true-up for 2019 revenue requirements.

2. Plant Material and Operating Supplies and Prepayments

On page 18 of the Petition, the Company explained that the $650 million purchase price includes approximately $4 million in inventory for turbine blades currently on order and the market value of the long-term water supply agreement with the City of Mankato. The Company

[3] MN Rules 7825.2500 states that the FCA reflects, "Changes in cost resulting from changes in the federally regulated wholesale rate for energy purchased and changes in the cost of fuel consumed in the generation of electricity." MN Rules 7825.2400, subp. 7 defines the cost of energy purchased as "the cost of purchased power and net interchange defined by the Minnesota uniform system of accounts, class A and B electric utilities, account 555 … ." MN Rules 7825.2400, subp. 8 defines cost of fossil fuel as "the current period withdrawals from account 151 as defined by the Minnesota uniform system of accounts … ."

noted that the estimated future benefits of the water supply agreement are $18 million when compared to procuring reclaimed water from the City of Mankato without the benefits of the existing contract.

The Company provided, in the Petition's Attachment I, the journal entries to record the acquisition of the MEC I and MEC II assets. The first journal entry included $4.245 million in Plant Materials and Operating Supplies, which is largely for the approximately $4 million in turbines blades. The first journal entry also included $9.0 million in Prepayments. The Department asked the Company in Department Information Request No. 2 (a) to provide a breakout of the Prepayments. The Company explained that the $9 million in Prepayments is entirely attributable to the prepaid water expense associated with the water supply agreement with the City of Mankato. The Company noted that, as of December 2017, Southern carried a deferred value of that prepaid expense at $8.8 million and a current value of $711,000.

The Department asked the Company in Department Information Request No. 2 (b) to explain the accounting and ratemaking for the $9 million in Prepayment once closed out to Xcel's books. The Company provided the following response:

> The $9 million estimated prepaid value will be recorded to account 165 (Prepayments). The final balance will be amortized based on the term of the water supply agreement to account 548 {Generation Expenses} which we would propose to be included in our annual revenue requirement. We would propose to include the unamortized prepayment in rate base using the actual thirteen-month average balance for the test year.

Based on our review, the Department considers the accounting and ratemaking for the Plant Materials and Operating Supplies (turbine blades) and Prepayments (water supply agreement) to be reasonable.

3. Transaction Costs

On Attachment I of the Company's Petition, Xcel's second journal entry records estimated transaction costs of $450,000 for acquiring MEC I and MEC II. In Information Request No. 3 (a) the Department asked the Company to provide a detailed breakout and explanation for the $450,000 in transaction costs. The Company provided the following response:

> (a) The $450k transaction costs represent an estimate of the legal and regulatory filing fees associated with transaction. We estimated the $450k number based on:
> - $234k in outside counsel fees billed as of 11/20/2018;
> - An estimated $50k in additional outside counsel fees to complete the transaction legal work after 11/20/18;

- $125k in Hart-Scott-Rodino filing fees to be paid to the Federal Trade Commission; and
- An additional $41k for support and fees associated with closing the transaction.

The Department asked the Company in Information Request No. 3 (b) to use the detailed breakout of transaction costs to provide support to show that these types of costs are not already included in Xcel's base rates. Additionally, the Department asked the Company in Information Request No. 3 (c) to explain and provide support for why these transaction costs should be allowed to be capitalized and included in rate base. The Company provided the following responses:

> (b) The budget for the 2016 test year in our rate case was developed in mid-2015 —well before we commenced discussions regarding the acquisition of the Mankato facility. We therefore did not account for the transaction or the associated legal fees when developing the 2016 test-year budget.
>
> Moreover, that rate case test-year budget included a total of $3,985,759.86 in legal fees and, of that total, only $5,000 was budgeted for outside legal services for the acquisition of assets, of which this transaction would fall into.
>
> Attachment A breaks down the test-year budget of $3,985,759.86 into separate categories of legal services that comprise the total and shows the $5,000 budget in the category titled "Purchase Power Other." Given the timing and components of our test-year budget, we believe it is reasonable to conclude that $507,000 budgeted for the legal fees associated with the Mankato acquisition are incremental to the legal fees already built into the Company's base rates.
> (c) The legal services provided in this matter pertain to the exploration, negotiation, and additional considerations related to the acquisition of this asset. It is therefore appropriate to capitalize these costs as part of the overall asset acquisition.

DOC IR No. 3
Attachment A - Page 1 of 1

Northern States Power Company

NSPM O&M Expenses
General Counsel Business Area
Expense Type 713100-Consulting/Prof Svcs-Legal

Detailed Expenses by FERC Cateogry

506-Misc Steam Pwr Exp	$ 80,000
524-Nuclear Power Misc Exp	$ 321,000
539-Hydro Oper Misc Gen Exp	$ 5,000
549-Oth Oper Misc Gen Exp	$ 175,000
557-Purchased Power Other (1)	$ 5,000
566-Trans Oper Misc Exp	$ 37,000
923-A&G Outside Services	$ 3,362,760
Total	**$ 3,985,760**

(1) Legal expenses related to purchase power agreemens (similar to Benson work) would be booked in the FERC 557.

After reviewing the Company's above responses regarding transaction costs, the Department recommends not approving cost recovery from ratepayers for the $450,000 in transaction costs. The Department asked the Company to show that representative amounts of these types of transaction costs were not already included in Xcel's base rates, which we believe Xcel was unable to show based on the above responses. As shown in Attachment A, Xcel had almost $4 million in legal costs built into base rates and $3.362 million of these costs appear to be generic "A&G Outside Services" not tied to a specific type of transaction. Additionally, in the Commission's January 23, 2018 *Order Approving Petitions, Approving Cost Recovery Proposal, and Granting Variances*, regarding the termination of Xcel's power purchase agreement with Benson Power, LLC (Docket No. E002/M-17-530), the Commission did not allow recovery of legal expenses and specifically stated in Ordering Paragraph 3:

> 3. The Commission hereby approves Xcel's request for the creation of a regulatory asset for the costs associated with the transaction, except the recovery of legal expenses, which are built into base rates. The rate of return on the asset is subject to future revision by the Commission and any payments by customers through the FCA are subject to a true-up.

Additionally, the Department noted in our review of Xcel's FERC filing for MEC I & MEC II in Docket No. EC19-28 that Xcel made a hold-harmless commitment for wholesale customers. Specifically, NSPM committed, for a period of five years from the acquisition date, to hold wholesale requirements power customers[4] and wholesale transmission customers harmless from the rate effects of the proposed transaction. For the five years, NSP committed not to

[4] If NSMP were to acquire any such customers in the next five years.

seek from wholesale customers any transaction-related costs, including costs incurred to effectuate the proposed transaction, or any acquisition premium, in wholesale power revenue requirements or transmission service revenue requirements, except to the extent that NSPM can demonstrate (through a separate Federal Power Act Section 205 filing of the Interchange Agreement) that savings related to the proposed transaction are equal to or exceed all of the transaction-related costs so included.

The Department recommends that the Commission require Xcel's commitment to hold wholesale power customers harmless to apply to Minnesota retail customers.

The Department concludes under this section that:

- Xcel was unable to show these types of transaction costs were not already included in base rates;
- the Commission's January 23, 2018 decision in the Benson docket denied recovery of legal costs in addition to the amounts charged to ratepayers in 2017 and 2018 base rates; and
- Xcel's five-year hold-harmless commitment for wholesale customers should also apply to the Company's Minnesota retail customers.

Thus, the Department recommends that the Commission deny cost recovery from retail ratepayers for the $450,000 in transaction costs.

4. Net Book Value of MEC I and II

According to the Company on page 45 of the Petition:

> The net book value of MEC's property, plant and equipment (including construction work in progress) is $495 million as of September 30, 2018 based on Financial Statements provided by Southern Power. Taking into consideration estimated remaining project costs associated with MEC II and additional assets to be acquired, the estimated net book value of the assets to be acquired at May 31, 2019 is $541 million.

The Office of Attorney General – Residential Utilities and Antitrust Division (OAG), asked Xcel in OAG Information Request No. 44 (OAG IR 44) to provide all information to support the $495 million and $541 million net book value (NBV) assertions, including the referenced financial statements from Southern. The Department noted in its review of Attachment B of Xcel's response to OAG IR 44 that Accumulated Depreciation for MEC I **[TRADE SECRET HAS BEEN EXCISED]**. Xcel's Attachment B in its response to OAG IR 44 contains a note that states that this amount **[TRADE SECRET HAS BEEN EXCISED].**

The Department is concerned that MEC I was already placed in service and continues to operate under its PPA to Xcel, so **[TRADE SECRET HAS BEEN EXCISED].** Thus, the Department recommends that the **[TRADE SECRET HAS BEEN EXCISED]** should be recorded and reflected in the NBV, thereby reducing Xcel's estimated $541 million NBV by the same amount.

Additionally, the Department notes that Xcel should be required to record and reflect additional depreciation expense of approximately **[TRADE SECRET HAS BEEN EXCISED]** for the period between the June 1, 2019 purchase date and the inclusion of MEC in base rates, which is likely to be as of January 1, 2020, thereby reducing Xcel's estimated $541 million NBV by the same amount.

5. Acquisition Adjustment

On Attachment I of the Company's Petition, the Company's third journal entry records an acquisition adjustment of $96.194 million included in the purchase price. An acquisition adjustment is the amount that is above or in excess of the net book value (original cost of the plant less accumulated depreciation). The Company noted on page 45 of the Petition that an acquisition adjustment of $96 million will be recognized as part of the purchase price, which the Company intends to request to include in rate base with a full return over the same useful life of the plant investment. Xcel stated in response to Department Information Request No. 4 (a) that:

> Within Attachment G- Revenue Requirements, the entire acquisition cost, including the acquisition adjustment, is reflected in the purchase price of MEC I and MERC II and is amortized over the estimated useful life of the plant, which is 2046 and 2054 for MEC I and MEC II, respectively.

The Department asked Xcel to provide support for why ratepayers should pay for the $96.194 million acquisition adjustment, including identifying offsetting benefits for ratepayers. Xcel provided the following response to Department Information Request No. 4 (b):

> The purchase price adjustment represents an estimate of the purchase price in excess of the net book value of the acquired assets. The net book value reflects the asset carrying value per Southern Power's accounting records and is not representative of the fair market value of the plant. As our analysis shows, Xcel Energy's customers will realize savings from the acquisition at the purchase price, including the acquisition adjustment, when compared to continuing with the PPAs and securing replacement power post PPA.

The Department also asked Xcel to provide citations to cases where acquisition adjustment recovery was allowed for plants already devoted to public service. Xcel provided the following response to Department Information Request No. 4 (c):

> The Uniform System of Accounts of the Federal Energy Regulatory Commission requires any difference between the original plant cost and the cost to acquire to be recorded as an acquisition adjustment (*See* Title 18, Chapter I, Subchapter C, Part 101).
>
> An example of when an acquisition adjustment was allowed occurred in December 2010, with PSCo's purchase of Blue Spruce Energy Center and Rocky Mountain Energy Center from Calpine Development Holdings, Inc. and Riverside Energy Center LLC (FERC Docket Nos. EC10-71-000; AC11-99-000).

The Department notes that traditionally, utility assets are recorded and recovered using the original cost of the asset and the related accumulated depreciation or resulting net book value of the asset. Acquisition adjustments are on top of the net book value and as a result require a significant finding of benefits to offset or justify this higher acquisition adjustment or premium before rate recovery is allowed, especially for utility assets that were already being used for public service (like MEC). Use of net book value in rate base is consistent with Federal Energy Regulatory Commission requirements and Minnesota requirements under 216B.16, subd. 6, which states:

> ***SUBD. 6. FACTORS CONSIDERED, GENERALLY.***
> The commission, in the exercise of its powers under this chapter to determine just and reasonable rates for public utilities, shall give due consideration to the public need for adequate, efficient, and reasonable service and to the need of the public utility for revenue sufficient to enable it to meet the cost of furnishing the service, including adequate provision for depreciation of its utility property used and useful in rendering service to the public, and to earn a fair and reasonable return upon the investment in such property. In determining the rate base upon which the utility is to be allowed to earn a fair rate of return, the commission shall give due consideration to evidence of the cost of the property when first devoted to public use, to prudent acquisition cost to the public utility less appropriate depreciation on each, to construction work in progress, to offsets in the nature of capital provided by sources other than the investors, and to other expenses of a capital nature. **For purposes of determining rate base, the commission shall consider the original cost of utility property included in the base and shall make no allowance for its estimated current**

> **replacement value.** If the commission orders a generating facility to terminate its operations before the end of the facility's physical life in order to comply with a specific state or federal energy statute or policy, the commission may allow the public utility to recover any positive net book value of the facility as determined by the commission.

As noted by Xcel, FERC requires acquisition adjustments to be recorded separate from FERC account 101, Electric Plant In-Service, in FERC account 114, Electric Plant Acquisition Adjustments.[5] If the Company receives regulatory approval for the cost recovery of the acquisition adjustment, then the Company is allow to amortize the acquisition adjustment to account 425, Miscellaneous Amortization, over the life of the related plant.

The Department notes that the determination of whether MEC I and MEC II are needed is addressed in the Resource Planning Review of Costs and Benefits section below. However, if the Commission were to determine that the MEC I and MEC II purchase is needed, then there would have to be consideration of the $96.194 million acquisition adjustment to determine whether this is a reasonable amount, and if so, who pays for it (ratepayers or shareholders).

The Department notes that competitive bidding would be a way to ensure that the acquisition adjustment or premium is reasonable. Unfortunately a competitive bid process was not used in this case. Additionally, FERC uniform system of accounts supports a net book valuation of utility plant, especially for plant that is already being used in public service. However, FERC uniform system of accounts does allow for the opportunity of an acquisition adjustment which would require approval from the rate regulator and a clear showing of benefits that justify or offset this higher acquisition adjustment cost.

As noted above, Xcel provided only one example of when an acquisition adjustment was allowed rate recovery, which occurred in another jurisdiction on December 2010 with PSCo's purchase of Blue Spruce Energy Center and Rocky Mountain Energy Center from Calpine Development Holdings, Inc. and Riverside Energy Center LLC (FERC Docket Nos. EC10-71-000; AC11-99-000). The Department reviewed this FERC proceeding and could not find in the petition the journal entries for the actual acquisition adjustment. However, the Department noted the following in a June 6, 2011 filing of Final Accounting Entries in Docket EC10-71-000 on page 8:

> Third, the use of fair value based on the unique circumstances present here will ensure that the Commission's accounting regulations do not have unintended impacts on state-supervised RFPs. In this case, PSCo's acquisition of Blue Spruce and Rocky

[5] See FERC Uniform System of Accounts – Electric Plant Instruction No. 5, Electric Plant Purchased or Sold and FERC Account 114, Electric Plant Acquisition Adjustments.

> Mountain was at less cost to PSCo (and its customers) than either new-build options or PPAs, as measured on a consistent Present Value Revenue Requirement basis. Indeed, the CPUC-supervised process was specifically designed to value each resource type on an "all-in" basis without any adjustment for specific resource types.[footnote 19 omitted] Strict adherence to original cost, however, as opposed to fair value would create substantial accounting differentials between resource categories (existing resources vs. new-build vs. PPAs) that could lead to cost recovery differentials. If, for example, a portion of the cost of a generation asset is labeled an "acquisition adjustment," then a different standard is applied to those costs and a utility seeking to recover such costs through cost-based rates must meet a "heavy" burden to justify cost recovery. [footnote 20 is below] On the other hand, if an asset is brand new, there is no accumulated depreciation and no acquisition adjustment. PPAs do not present acquisition adjustment issues. Thus, if a utility is compelled to value acquired generation assets at original cost, it is at risk for recovery of any amounts classified as an acquisition adjustment notwithstanding the fact that, as here, the total costs of the generation assets are lower than other resource options that do not carry this same risk.

The Department has two takeaways based on the above cite. First, the use of fair value was unique in that case, based on a set of circumstances that does not exist here. For example, there was a state-supervised RFP process including a competitive bid process, which is not true in the current proceeding. Second, in that case, "PSCo's acquisition of Blue Spruce and Rocky Mountain was at less cost to PSCo (and its customers) than either new-build options or PPAs," a fact that does not exist in the current proceeding. Thus, the Department concludes that the above case is not sufficient to demonstrate that it is reasonable to charge Xcel's ratepayers for the "acquisition adjustment" which must still meet a "heavy" burden to justify cost recovery.

Based on our review to date, the Department recommends that the $96.194 million acquisition adjustment be denied. The Department provides the following to support this recommendation:

- MEC is an asset that is already devoted to public service and is used and useful under an existing PPA;
- For purposes of FERC and Minnesota ratemaking – use of the net book value is appropriate for setting rates;
- Xcel did not do a competitive bid process; and
- Allowing approval of an acquisition adjustment must meet a heavy burden to justify cost recovery – which we don't believe Xcel has

fully met as further discussed in the next section – Comparison of PPA and Revenue Requirement Ownership.

6. Comparison of PPA and Revenue Requirement Ownership

Xcel on page 34 of its Petition provided Table 8, which shows the incremental revenue requirement impact of MEC ownership for 2019 through 2024. Xcel's Table 8 shows that the "Capital Cost of Mankato Purchase" (ownership costs) are slightly higher than the "Fixed Savings of Mankato PPA" (costs of PPA) - plus the "VOM/Fuel/Market Costs/Savings." The "VOM/Fuel/Market Costs/Savings" includes net savings due to lower variable operating and maintenance expense (O&M), slightly higher fuel and carbon dioxide (CO_2) emission costs due to the expected increase in output of the plant, and some Midcontinent Independent System Operator (MISO) market revenues, for this time period.

The Department asked Xcel to provide supporting calculations and information for the information provided in Table 8. Xcel provided this information in response to Department Information Request No. 7, parts (a) through (e). The Department considers the "VOM/Fuel/Market Costs/Savings to be fairly small and rather speculative and based largely on a significant level of assumptions that may or may not occur. As a result our focus was mostly on the "Capital Cost of Mankato Purchase" (ownership method via revenue requirements) compared to the "Fixed Saving of the Mankato PPA" (PPA method).

The Department asked Xcel to extend out its incremental revenue requirement calculation of ownership compared to the PPAs for the entire life of MEC I and MEC II (rather than just through 2024). Xcel provided the following in response to Department Information Request No. 7 part (f):

> Extending the PPAs for the entire life of MEC I & MEC II results in a net cost of $255MM in comparison to the MEC ownership case. The high renewables scenario with the PPA extensions results in a net cost of $162MM when compared to the MEC Ownership option with the high renewable tail.

Incremental RR Impact High Renewables

	2018 PVRR
Capital Cost of Mankato Purchase	915
Fixed Savings of Mankato PPA	(571)
Fixed Cost/Expansion Plan Cost/(Savings)	(364)
VOM Cost/(Savings)	(32)
Coal	(3)
Gas	(29)
Fuel Cost/(Savings)	28
Coal	(41)
Gas	72
Other	(2)
Market Cost/(Savings)	(28)
CO2 Cost/(Savings)	5
Externalities Cost/(Savings)	(65)
PPA Starts/Own Start Fuel Cost/(Savings)	(48)
Total Cost/(Savings)	(162)

The Department notes that our focus is primarily on the first three lines of the above table. The "Capital Cost of Mankato Purchase" of $915 million reflects the present value of revenue requirements under the ownership method. The sum of lines 2 and 3, which totals $935 million, reflects the present value under the PPA method. As a result, the ownership method compared to the PPA method provides fairly similar present value amounts over the life of the plant.

In Attachment G of the Petition, Xcel provided a detailed spreadsheet that included inputs and assumptions for the revenue requirements used in the ownership method. In addition, in its Response to Department Information Request No. 8, Xcel provided responses to several of the Department's questions about these assumptions. Based on limited review, the Department generally considers Xcel's inputs and assumptions to be reasonable with the exception of property taxes. The Department notes that **[TRADE SECRET HAS BEEN EXCISED].**

The Department also notes that Xcel's actual plant life may be shorter than estimated due to future environmental concerns. In addition, we think it is important to recognize that there are operational and resulting cost risks that occur as a result from moving from a PPA to ownership,[6] including:

- decommissioning would become the responsibility of Xcel and its ratepayers;
- plant outages and equipment failures would become the responsibility of Xcel and its ratepayers;
- risk of higher property taxes would be shifted to Xcel and its ratepayers; and

[6] These ownership risks were confirmed in Xcel's response to OAG Information Request Nos. 15, 25.1, 35 and 74.

- risk of higher O&M expenses would be shifted to Xcel and its ratepayers.

The Department concludes that the present value revenue requirement amounts assuming ownership versus continuing with the PPAs over the life of the MEC plants are similar. However, there are some significant cost risks that would be shifted to Xcel and its ratepayers should the plant purchase be approved, including:

- decommissioning would become the responsibility of Xcel and its ratepayers;
- plant outages and equipment failures would become the responsibility of Xcel and its ratepayers;
- risk of higher property taxes would be shifted to Xcel and its ratepayers; and
- risk of higher O&M expenses would be shifted to Xcel and its ratepayers.

As a result, the Department does not believe Xcel has shown clear benefits of ownership.

C. RESOURCE PLANNING REVIEW OF COSTS AND BENEFITS

1. Resource Planning Analysis

a. Prior IRP Order

The Commission's January 11, 2017 *Order Approving Plan With Modifications and Establishing Requirements for Future Resource Plan Filings* (IRP Order) in Xcel's most recent IRP proceeding approved, with modifications, Xcel's 2016–2030 IRP (Docket No. E002/RP-15-21). The IRP Order's ordering paragraphs stated, in part:

> 2. Xcel's Strategist-modeled energy and demand forecast is acceptable for planning purposes but may not be used to support any resource acquisition proposal beyond the five-year action plan.
>
> 3. It is reasonable to acquire at least 1000 MW of wind by 2019. Acquisition of greater than 1000 MW may be approved upon submission of evidence …
>
> 4. Xcel's resource plan is modified as follows:
>
>   a. to change Xcel's planned CT (combustion turbine) additions in the 2025–2030 time frame to provide instead for adding the most cost-effective combination of resources consistent with state energy policies, including but not limited to the following resource options: large

> hydropower, short-term life extensions of Xcel-owned peaking units, natural gas combustion turbines, demand response, utility-scale solar generation, energy storage, and combined heat and power.
>
> …
>
> 8. The Commission finds that more likely than not there will be a need for approximately 750 MW of intermediate capacity coinciding with the retirement of Sherco 1 in 2026.
>
> 9. Xcel is authorized to file a petition for a certificate of need under Minn. Stat. § 216B.243 to select the resource or resource combination that best meets the system resource and reliability needs associated with the retirement of Sherco 1 in 2026 …

Regarding the IRP Order's points 8 and 9 above, and subsequent to the IRP Order, Laws of Minnesota 2017, Chapter 5 stated:

> Section 1. NATURAL GAS COMBINED CYCLE ELECTRIC GENERATION PLANT.
> (a) Notwithstanding Minnesota Statutes, section 216B.243 and Minnesota Statutes, chapter 216E, a public utility may, at its sole discretion, construct, own, and operate a natural gas combined cycle electric generation plant as the utility proposed to the Public Utilities Commission in docket number E-002/RP-15-21, or as revised by the utility and approved by the Public Utilities Commission in the latest resource plan filed after the effective date of this section, provided that the plant is located on property in Sherburne County, Minnesota, already owned by the public utility, and will be constructed after January 1, 2018.
>
> (b) Reasonable and prudently incurred costs and investments by a public utility under this section may be recovered pursuant to the provisions of Minnesota Statutes, section 216B.16.
>
> (c) No less than 20 months prior to the start of construction, a public utility intending to construct a plant under this section shall file with the commission an evaluation of the utility's forecasted costs prepared by an independent evaluator and may ask the commission to establish a sliding scale rate of return mechanism for this capital investment to provide an incentive for the utility to complete the project at or under the forecasted costs.

Thus, it appears that the specific need for intermediate capacity in 2026 identified by the Commission was addressed by the Minnesota Legislature. As indicated by the IRP Order's point 4, the remaining needs in the 2025–2030 time frame call for a comprehensive, IRP-type review.

b. Overview of Department's Approach

In general, the Department views an IRP as a discrete proceeding that happens at a point in time and that is then generally relied upon until the next IRP proceeding occurs. At the time a particular resource acquisition is proposed, typically one part of the analysis is to review the Company's latest capacity expansion modeling inputs for changes that are outside the boundaries studied in the prior IRP. If there are no such changes, then no further capacity expansion modeling (resource planning analysis) takes place and the prior IRP analysis and related Commission decisions are used. However, if subsequent data calls into question the assumptions underlying the previous IRP, then a limited re-analysis is performed to account for the new facts.

As an example, in Docket Nos. E002/M-13-603 and E002/M-13-716 Xcel proposed to acquire 750 MW of wind—far above the 100 MW to 200 MW level determined in the prior IRP. In the prior IRP proceeding, neither the Department nor Xcel explored the event that a significant amount (beyond 200 MW) of low-cost wind would be available in the near-term. Thus, a limited re-analysis was performed by Xcel and the Department for the purposes of the resource acquisition proceedings. The Commission's December 13, 2013 *Order Approving Acquisitions With Conditions* in Docket Nos. E002/M-13-603 and E002/M-13-716 recognized this process as appropriate:

> In various ways, the Joint C-BED Intervenors object that changes in circumstances arising since the Commission approved Xcel's last resource plan make it difficult to know whether Xcel's resource acquisition strategies are optimal. The Commission acknowledges these changes, and has already directed Xcel to issue a notice of changed circumstances. That said, while a resource plan is intended to plot a utility's course for the next 15 years, it is based on facts known as of a specific point in time. As more facts become known, circumstances change and utilities must adapt – even in the absence of a new resource plan order. [Citation omitted.]

This case presents similar circumstances in that the Company's analysis indicates that more intermediate capacity and energy should be acquired than was contemplated in the previous IRP. Xcel's proposed purchase of MEC effectively adds new intermediate capacity—above the level studied in the last IRP—after the current PPA with MEC I expires in 2026.

c. Comparison of Databases

The Department compared the base case values from Xcel's new model to the range of values the Department used in Xcel's prior IRP.[7] The initial comparison was for the years 2018 through 2032[8] for the following inputs:

- demand forecast;
- energy forecast;[9]
- Sherco coal prices;
- MEC I natural gas prices; and
- Riverside natural gas prices.

The results of the comparison indicate that the values for each input changed outside the bounds explored in the prior IRP in at least some years. Consistently, the changed values were below the lower bounds explored in the prior IRP's contingencies. In addition, the Department is aware of several supply units that existed in the prior IRP that have since been retired by Xcel.[10] Further, the Department is aware that, since the prior IRP, the Company added energy and capacity via numerous new wind projects, the re-powering of an existing wind project, and the extension of an existing power purchase agreement with a refuse-derived fuel (RDF) facility.[11]

While the Department's preference in a resource acquisition proceeding is to rely upon modifications to the database used in the prior IRP, in this case the large number and wide range of the necessary changes to the prior IRP database would essentially amount to a complete re-build of that database. Therefore, the Department opted to attempt to perform additional modeling in this proceeding using Xcel's new database.[12]

[7] See Docket No. E002/RP-15-21.
[8] The years 2018 through 2032 are present in both models—the Department's for the 2015 IRP and Xcel's for the instant docket.
[9] The forecast reviewed was from the outputs rather than the inputs, meaning after the effects of energy efficiency but before load management. In Strategist, load management is typically treated similar to a supply-side resource while energy efficiency is a forecast adjustment.
[10] For some examples, see Docket Nos. E002/M-17-530, E002/M-17-531, and E002/M-17-551. The Company notified the Commission of additional retirements via filings in Docket No. E002/RP-15-21.
[11] See Docket Nos. E002/M-16-777, E002/M-17-694, and E002/M-17-532.
[12] Xcel provided the new database and other Strategist-related information in response to Department Information Request No. 1.

d. Review of New Database

i. Table 6 Database

The Department reviewed the data in the Company's latest base case file.[13] This file corresponds to the data shown in Table 6 on page 28 of the Petition. From this review, the Department concluded that substantial time would be required to modify this database. The most significant problem that appeared in an initial review was that the capacity factors for the dispatchable units became rather high starting in 2027. This change is due to the retirement of numerous, energy-intensive units between 2023 and 2027.[14] For example, the more efficient peaking units have capacity factors in the range of 10 to 25 percent from 2027 to the end of the run in 2057. Typically, when capacity factors for peaking units exceed 5 to 10 percent on a consistent basis it is an indication that additional energy-producing units (typically baseload units, wind units and some conservation measures) will be economic.

In addition to the uneconomic operation of peaking units there are issues with the base case file in the operation of Xcel's intermediate units. The more efficient intermediate units have capacity factors in the range of 50 to 75 percent from 2027 to the end of the run in 2057. Typically, when capacity factors for intermediate units exceed 40 to 50 percent on a consistent basis it is also an indication that additional energy-producing units will be economic.

These high capacity factors represent a problem because Strategist is an economic model. When units operate in an uneconomic manner the model will use whatever tools are available to mitigate the uneconomic operations. In this case, the only tools available to Strategist are increased generation from existing units. Thus, all existing, dispatchable units—including MEC—will be perceived by the model as having benefits in that they can produce more energy, mitigating uneconomic operations of units higher in the dispatch order.[15] However, in the future such benefits are unlikely to be realized because a full range of potential mitigation measures—addition of new supply units, additional conservation, and so forth—will be tested.

Thus, here Xcel's Strategist base case perceived a benefit to running an intermediate unit at a 70 percent capacity factor because that result avoids operating a more expensive peaking unit. However, in reality the intermediate unit will not operate at such a high capacity factor because other, lower cost solutions to the excessive use of peaking units will be found. Thus, the

[13] In file "_MANKATO BASE.FSV"; provided in response to Department Information Request No. 1.
[14] For example, the following baseload and intermediate units retire in the mid-2020s: St. Paul District Energy (2023); Sherco 2 (2023); HERC (2024); Sherco 1 (2026); French Island, Red Wing, and Wilmarth RDF units (2026); MEC I (2026); LS Power Cottage Grove (2027). In addition, the following peaking units retire: Blue Lake 1 to 4 (2023); Wheaton 1 to 4 and 6 (2025); Invenergy 1 and 2 (2025); Inver Hills 1 to 6 (2026); and French Island 3 and 4 (2027). Finally, numerous wind units retire, as does the PPA with Manitoba Hydro (2025).
[15] The high capacity factors indicate that the mitigation did not completely eliminate the issue. The issue was limited to the extent possible.

benefits to high use of intermediate units such as MEC—to avoid operation of more expensive peaking units—are merely an artifact of Xcel's modeling process.

While it would have been possible to explore adding additional energy producing units to Xcel's model, Xcel already had done so via the "high renewable energy" scenarios; see Table 7 of the Petition. Given the issues described above, the Department recommends that the Commission not rely on the data in the Petition's Table 6.

ii. Table 7 database—with Spot Market on

The Department used the files provided by Xcel to transform the base case model (used for the Petition's Table 6) into the high renewable file.[16] This file corresponds to the data shown in Table 7 of the Petition. Once again the review eventually determined that substantial time would be required to modify the database.

The first significant problem that appeared in analysis of the database underlying Table 7 was that the incremental impact of the Company's purchase of MEC I and MEC II was dominated by changes in the amount of energy bought and sold in the spot market. To address this issue, the Department took the following steps.

First, the Department re-created the case where MEC I and MEC II operate under the existing PPAs but with high renewables required to be added. Second, the Department re-created the case where MEC I and MEC II are purchased by Xcel but again with the same high renewables required to be added. Third, the Department subtracted the outputs of the case where MEC I and MEC II operate under the current PPAs from the outputs of the case where MEC I and MEC II operate under Xcel ownership. This process results in making the incremental impact of Xcel's purchase of MEC I and MEC II available for review.

In terms of capacity, the two scenarios are identical for the years 2019 to 2026 with the exception that, under Xcel ownership, MEC I and MEC II provide a small amount of additional capacity. After that, for the years 2027 to 2033, the scenario with Xcel ownership of MEC I and MEC II shows an additional 300 MW of capacity.[17] This is largely attributable to the fact that MEC I provides capacity in the Xcel ownership scenario and does not under PPA scenario. For 2034 to 2057 the capacity position changes from year to year, but on average the two scenarios (ownership and PPA) have similar capacity. This is due to changes in the MEC II capacity dedicated to Xcel along with differing additions of generic combustion turbine and combined

[16] File "_MANKATO BASE.FSV" with the inputs in the file "_Scenario_BASE_HRE.INP" and potentially "_Scenario_OWN_HRE.INP" added; all provided in response to Department Information Request No. 1.

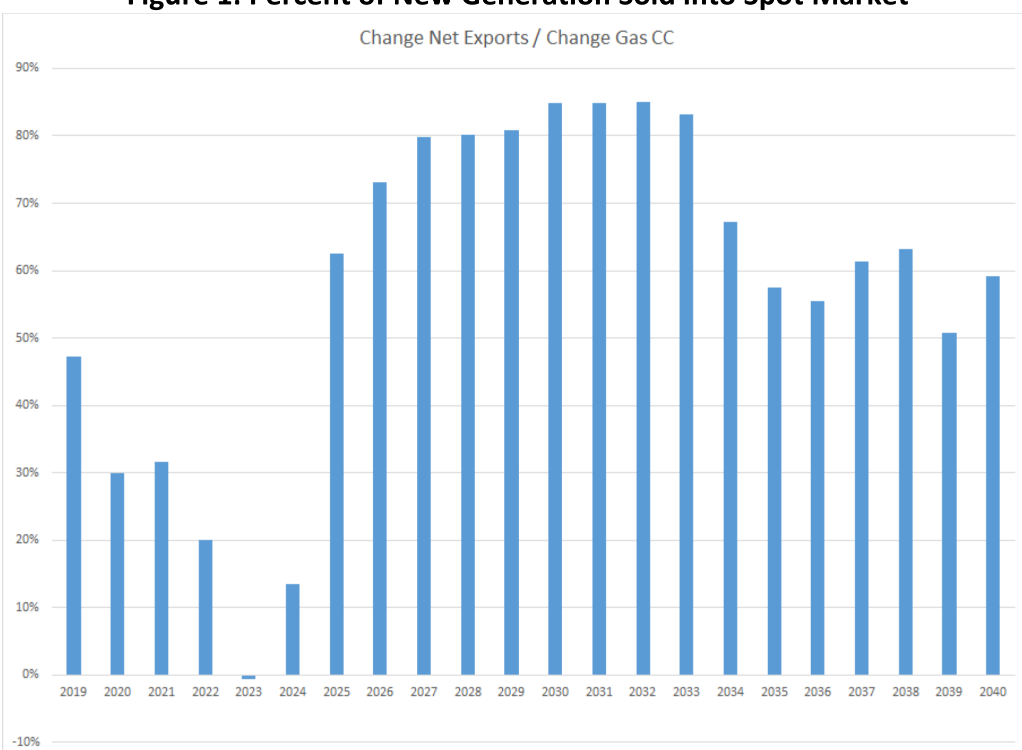
[17] The two scenarios' capacity levels are the same—except for the capacity provided from MEC I and MEC II—because Xcel requires the wind and solar units to be added on the same schedule and, due to a capacity surplus, no fossil fuel units are necessary until 2034. Thus, the expansion plan is the same (in the two high renewables cases) regardless of ownership until 2034.

cycle units. In any event, a short-term capacity market is available to value any capacity differential between the two scenarios—Xcel ownership and PPA.

While the capacity position is relatively similar most years, the two scenarios' energy performance is substantially different. For the years through 2040, the ownership scenario results in substantially more energy produced by natural gas-fueled units, corresponding to a decrease (usually under 5 percent) in generation by coal-fueled units and an increase in net exports.[18] After 2040, the ownership scenario results in substantially less energy produced by natural gas-fueled units and an offsetting increase in net imports.

The degree of reliance upon spot market sales to provide the benefits is illustrated in Figure 1 below. Figure 1 shows the change in net exports divided by the change in natural gas combined cycle generation in the years through 2040. Thus, Figure 1 shows the percentage of the increase in combined cycle generation that is sold into the spot market. Figure 1 demonstrates that over half of the additional energy resulting from Xcel's purchase of MEC I and MEC II is simply resold into the spot market during the years 2025 to 2040.

Figure 1: Percent of New Generation Sold into Spot Market



[18] Generation from nuclear, wind, solar, and hydro units is the same in both scenarios because these units are treated as non-dispatchable (they produce energy in amounts and at times determined by the modeler). Further, wind and solar are not available as options (they are forced into the model). This structure leaves Strategist with only coal (existing units), natural gas (new and existing units), and the spot market to change system energy production.

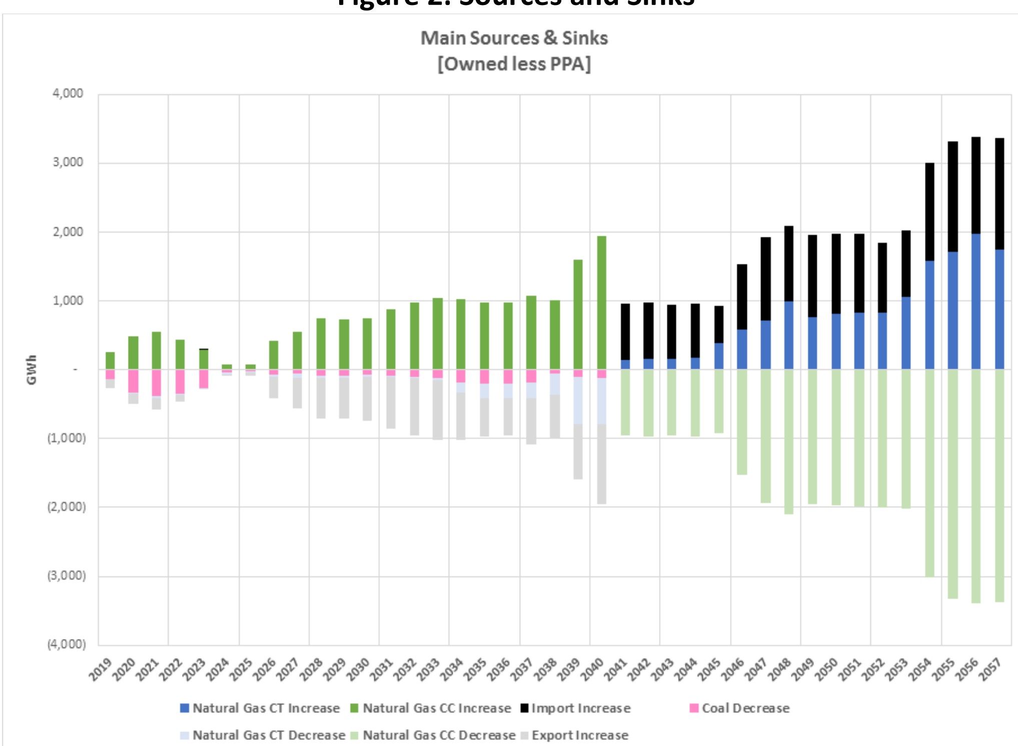
A second, more comprehensive but more complicated, picture is provided in Figure 2 below. Figure 2 shows the sources (increase in generation sold to Xcel's customers) above the zero point on the vertical axis and the sinks (decreases in generation sold to Xcel's customers) below zero on the vertical axis. The sources and sinks are changes attributable to the Company's proposed purchase of MEC I and MEC II.

Figure 2 shows that through 2040 the only source (increase in generation) is from natural gas combined cycle units, offsetting decreases in coal generation and natural gas combustion turbine generation, and also resulting in a substantial increase in net exports (as demonstrated in Figure 1).

After 2040 the purchase of MEC I and MEC II results in two sources - an increase in imports and natural gas combustion turbine generation - offsetting a decrease in natural gas combined cycle generation. In both periods the spot market plays a large role in the differences between the two systems (with and without Xcel's purchase of MEC I and MEC II).

Note that the change in 2040-'41 is triggered by the retirement of Xcel's last coal unit (Sherco 3) in 2040 and the different ways the two models (ownership and continued PPA) replace the capacity and energy lost in 2041 (addition of a large combined cycle unit in the PPA model versus addition of combustion turbines in the ownership model).[19]

Figure 2: Sources and Sinks



[19] Again, Strategist cannot react to changes in the system through changing the addition of wind and solar units since wind and solar are not available as options in Xcel's model.

The Department briefly reviewed Xcel's construct of the spot market to better understand what might be driving the importance of the spot market. For this review the Department reviewed Xcel's spot market prices for the first 20 years (2018 to 2037).[20] The Department started with the average, maximum, and minimum prices for each month of each year.

What immediately stood out was that average prices fit expectations:

- any one year's highest average prices occurring in summer or winter; and
- any one year's lowest average prices occurring in spring or fall;

In contrast, a year's maximum price tended towards the unexpected; a year's maximum price almost always occurred in the spring.[21] For example, the maximum prices in July were often substantially lower than the maximum prices in May.

To determine the extent of the high spring pricing the Department broadened the analysis from the maximum price (one observation each month) to all prices over $100 per MWh. The year 2033 was selected as a year with numerous (37) hourly prices over $100 per MWh. Of the 37 hourly prices, 20 were in the spring, 7 were in summer, and 2 were in fall, and 8 were in winter. Thus, the Company is forecasting spot market prices to be high in the spring much more often than any other season.

In addition, the Department reviewed the timing of the high prices.[22] Of the 37 high prices:

- 86.5 percent occurred during shoulder hours;
- 13.5 percent occurred during peak hours; and
- none occurred during off-peak hours.

This data is shown in Table 1 below.

Table 1: Distribution of High Prices in 2033 (LMP > $100)

	Winter	Spring	Summer	Fall	Sum
Off-Peak	0.0%	0.0%	0.0%	0.0%	0.0%
Shoulder	21.6%	51.4%	8.1%	5.4%	86.5%
Peak	0.0%	2.7%	10.8%	0.0%	13.5%
Sum	21.3%	54.1%	18.9%	5.4%	100.0%

[20] Strategist operates based upon a typical week each month, so there are 168 hours in a month. Each hour has its own price and the prices are varied each year.
[21] The only exception was the first four years—2018 to 2021.
[22] For simplicity the Department divided each day into off-peak hours (hours ending 1 to 6, 23, and 24); shoulder hours (hours ending 7 to 10, and 19 to 22); and peak hours (hours ending 11 to 18).

The data from Table 1 do not appear to the Department as representing a reasonable forecast of time periods subject to the risk of high market prices. While it might represent an interesting contingency, it should not be the only pricing curve analyzed.

In any event, because the average prices are lowest during the spring months, yet those same months have the most price spikes, it must be the case that the spring months also have the most very low prices. To determine exactly how Xcel's model inputs produced simultaneously high peak prices and low average prices, the Department reviewed the year 2033 for hours in which the spot market price is at the minimum.[23] The resulting data is summarized in Table 2 below.

Table 2: Distribution of Lowest Prices in 2033 (LMP at minimum)

	Winter	Spring	Summer	Fall	Sum
Off-Peak	0.0%	0.0%	0.0%	5.7%	5.7%
Shoulder	0.0%	7.5%	0.0%	0.0%	7.5%
Peak	17.0%	56.6%	9.4%	3.8%	86.8%
Sum	17.0%	64.2%	9.4%	9.4%	100.0%

Curiously, the instances of the *lowest* prices generally occur during the *peak hours*, especially during spring months.

To double check if this result was a onetime occurrence or a recurring phenomenon in Xcel's inputs, the Department also reviewed the year 2024. 2024 was chosen as that was the last year with a zero price input. The pattern for the high prices remained the same in 2024 as in 2033, dominated by high prices in the shoulder hours of spring months.[24] The pattern for the low prices also remained the same in 2024 as in 2033, again dominated by low prices in the peak hours of spring months.

To check if Xcel's pricing pattern presents a reasonable picture of the recent past, Xcel's spot market pricing pattern can be compared to recent history. The Department reviewed 2017 and 2018 real-time, spot market prices at the Minnesota hub.[25] High prices (above $100 / MWh) were predominantly in the peak hours (55 to 60 percent of high prices in both 2017 and 2018) or shoulder hours (37 percent). Low prices (less than $0 per MWh) were largely confined to the

[23] Essentially, after 2024 the minimum price is equivalent to a $0 per MWh price for energy plus an amount to account for the use of the Commission's CO2 internal cost value starting in 2025 plus the impacts of inflation and heat rate changes.
[24] In 2024 I used $65 per MWh as the threshold for "high" to obtain 21 observations.
[25] While MISO has a day ahead and real time market and much load is cleared in the day-ahead market, the Department tracked the real time data for two reasons. One, to manage the time required and second, to track how the market responds to unexpected events that stress the market. Thus, the real time data was readily available to the Department.

off-peak hours in 2017 (almost 80 percent of 2017's negative Locational Marginal Prices (LMPs)) or, in 2018, distributed between off-peak hours (55 percent of 2018's negative LMPs) and shoulder hours (35 percent). Given the units available in the spot market these results make sense. By contrast, Xcel's Strategist inputs reflect an expectation that the pricing structure in the MISO spot market will be substantially different in the not too distant future.

Overall, given:

- the significant role played by selling energy into the spot market;
- the curious pricing structure used by Xcel; and
- the lack of contingencies or alternative pricing structures;

the Department recommends that the Commission not make any decisions based upon use of Xcel's Strategist model where the spot market is in use. In essence, the Department concludes that the structure of the inputs does not appear to be a reasonable forecast of the future and the Department is not aware that alternative pricing structures were explored by the Company via contingency analyses. Overall, the Department recommends that the Commission not rely upon the data in the Petition's Table 7 with the spot market on.

iii. Table 7 database—with Spot Market off

The Department notes that Table 7 includes two contingencies that do not have Xcel's spot market structure turned on.[26] However, the Department does not recommend that the IRP analysis focus on only two contingencies. Such a limited set of results cannot cover a broad enough array of potential futures so as to adequately analyze risk. Therefore, the Department did not review in detail the two remaining files. However, the Department notes that additional issues likely exist in this database, such as using skewing the results by using the Commission's high externality and CO_2 internal cost values in the base case rather than the mid-point; removing must-run status from the first segment of coal units [see the Company's reply to Sierra Club Information Request No. 5-1 (a)][27]; and so forth.

e. Conclusion Regarding Resource Planning Analysis

Overall, the Department concludes that:

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[26] Of the two contingencies, one contingency simulates a minimal interaction with the spot market by providing a credit for what is referred to as "dump" energy in Strategist. In Strategist, must-run energy in excess of load serving needs is considered "dump" energy. The other contingency did not provide a value to dump energy—in essence assumes a zero market price.

[27] Under the Commission's high CO_2 cost values it is possible that a natural gas combined cycle unit will have a lower variable cost than a coal unit, thus leading to the natural gas unit to be dispatched first.

- the intermediate capacity needs specifically identified in the Company's last IRP will be met by a new unit to be built at the Sherco site, per the Laws of Minnesota 2017, Chapter 5;
- there have been numerous changes since the Company's last IRP that indicate new resource planning analysis is warranted;
- much of the Company's resource planning analysis appears to contain significant issues; and
- the remaining analysis provides an insufficient basis for decision-making.

Therefore, the Department concludes that Xcel has not demonstrated its proposal to be reasonable. Thus, the Department recommends that the Commission reject the Company's proposal until Xcel is able to address the issues discussed above.

2. Resource Acquisition Analysis

a. Commission Bidding Orders

Regarding resource acquisitions by Xcel, the Commission's January 11, 2017 *Order Approving Plan with Modifications and Establishing Requirements for Future Resource Plan Filings* (2017 Order) in Docket No. E002/RP-15-21 stated:

> The Commission has approved a two-track resource acquisition process—which among other things provides that a competitive bidding process governs when Xcel does not submit a proposal in a competitive resource procurement process (Track 1), and that a Certificate-of-Need-like process governs procurement when Xcel does submit a proposal (Track 2). *In the Matter of Northern States Power Company d/b/a Xcel Energy's Application for Approval of its 2004 Resource Plan*, Docket No. E-002/RP-04-1752, Order Establishing Resource Acquisition Process, Establishing Bidding Process Under Minn. Stat. § 216B.2422, Subd. 5, and Requiring Compliance Filing (May 31, 2006). More detail on the lengthy history of the two-track bidding process can be found in the Department's Comments, pp. 44–50. (July 8, 2016).

Modifications to the existing bidding process were discussed in the course of Xcel's 2015 IRP.[28] However, regarding the modifications, the 2017 Order stated "The Commission will therefore approve the bidding process described by Xcel for the limited purpose of acquiring wind and solar resources in the 2016–2021 timeframe." Therefore, the modified process from the 2017 Order is not relevant to this proceeding.

[28] See Xcel's January 29, 2016 Supplement to Xcel Energy's 2016-2030 Upper Midwest Resource Plan and the Department's July 8, 2016 comments.

The Department's July 8, 2016 Comments in Docket No. E002/RP-15-21, in discussing the standard Commission-approved bidding process, stated that "the original bidding process specifically included an exemption for capacity decisions involving existing generating units such as re-powering existing facilities, recapturing of capacity of existing facilities, capacity enhancements to existing facilities, and retention of the capacity of an existing facility (i.e., plant life extension)."

The Commission's May 31, 2006 *Order Establishing Resource Acquisition Process, Establishing Bidding Process Under Minn. Stat. §216B.2422, Subd. 5, and Requiring Compliance Filing* (2006 Order) in Docket No. E002/RP-04-1752 established the current two-track resource acquisition process. Briefly, when Xcel intends to submit a self-build proposal, a certificate of need process is used and when Xcel does not intend to submit a self-build proposal, an Xcel-run bidding process is followed. The 2006 Order did not contain a clear discussion of continuing or discontinuing the exemption for capacity decisions involving existing generating units.

Overall, a well-run bidding process should create the best result for ratepayers in instances where a competitive market exists.[29] Therefore, in principle, the Department supports a bidding process as the primary tool for resource acquisition. However, there are other considerations. First, the proposal arose, not necessarily to address a need identified within the Commission's resource planning process, but from an opportunity that occurred due to Southern's desire to sell the MEC I and MEC II projects. Since Southern owns the existing MEC I and MEC II projects and Southern has indicated desire to sell, Southern controls the timing as far as the current proposal is concerned. Second, the proposal involves existing units and the Commission's orders are not clear regarding existing units. Third, there are acquisition-related provisions in the Commission-approved PPAs. These provisions are discussed in the next section.

b. MEC I and MEC II PPAs

The MEC I facility is under contract to Xcel until 2026 via a PPA—see the Petition's Attachment B. The MEC II facility is under contract to Xcel via the *Power Purchase Agreement, Between Mankato Energy Center II, LLC, a Delaware Limited Liability Company, and Northern States Power Company, a Minnesota Corporation* (MEC II PPA)—see the Petition's Attachment C. Section 19.2 of the MEC II PPA states:

> At any time after the Commercial Operation Date, if Seller or any Affiliate of Seller decides to solicit or proceed with unsolicited third-party offers to convey all or substantially all of the Facility Property and the assets comprising the MEC I Facility or a majority

[29] Requirements include numerous, qualified, project developers; a fair, rigorous process for evaluating proposals; a defined need to be met; and so forth.

> of the interests in Seller and MEC I[30] (each a "Proposed Transaction") to an unaffiliated third party, Seller shall in advance of any such solicitation or pursuit of unsolicited offers provide Company with the right of first offer ("ROFO").

In addition, the Commission's February 5, 2015 *Order Approving Power Purchase Agreement With Calpine, Approving Power Purchase Agreement with Geronimo, and Approving Price Terms with Xcel* in Docket No. E002/CN-12-1240 stated that, regarding the MEC II facility "The Commission selects the proposal as a resource that fits Xcel's need and approves Xcel's draft power purchase agreement with Mankato Energy Center II, LLC." Therefore, the Commission-approved MEC II PPA contains the potential for Xcel to acquire MEC I and MEC II facilities outside of the standard bidding process. In essence, there is a limited exception to Xcel's standard bidding requirement to acquire MEC I and MEC II facilities through a ROFO process.[31] Issues regarding the potential exemption for existing units are not relevant.

3. Protecting Ratepayers from Risks

a. Financial Risks

The Department's review focused on the difference between the contract and utility ownership. Elsewhere in these comments is a review the benefits and costs of these structures from economic and accounting perspectives. The remaining issue regards the risk inherent in the *Membership Interest Purchase Agreement* (MIP Agreement) which implements the transaction.[32] For contracts such as the MIP Agreement, there are two main financial risks that may have negative impacts on Xcel's ratepayers:

1. a seller default and termination of the MIP Agreement and the underlying purchase of energy and capacity from MEC I and MEC II before the expiration of the contract period, and

2. entitlement by a lender or other party, as a result of the seller's failure to pay debt, to take over the project and terminate the MIP Agreement and the underlying purchase of energy and capacity from MEC I and MEC II.

---

[30] Note that page A-12 of the MEC II PPA defines MEC I as having "the meaning set forth in the first paragraph of this PPA." In turn, the first paragraph states "Mankato Energy Center II, LLC, a Delaware limited liability company with offices at 717 Texas Avenue, Suite 1000, Houston, TX 77002 ("Seller"), and, with respect to Section 2.2 and Section 19.2 only, Mankato Energy Center, LLC, a Delaware limited liability company with offices at 717 Texas Avenue, Suite 1000, Houston, TX 77002 ("MEC I")." Therefore, the Department understands that the term MEC I in section 19.2 refers to the entire facility (MEC I and MEC II).

[31] Similar provisions appear in other Commission-approved contracts. For a recent example, see Docket No. E015/M-18-545.

[32] The Department notes that the MIP Agreement at Section 4.16(c) on page 30 refers to a Section 4.05(h), which does not exist.

Under these events, Xcel may be forced to find what may be more costly replacement energy and capacity when the MIP Agreement, along with the underlying PPAs, is terminated. The analysis below is confined to the incremental impact of the MIP Agreement on the financial risks associated with MEC I and MEC II.

Regarding the risk of a seller's default and the risk of a lender taking over the project and terminating the MIP Agreement and underlying PPAs, the MIP Agreement substantially reduces the contract period. Thus, one incremental impact is a reduction of the current risks equivalent to the difference between the date Xcel takes over the generation facility and the current termination date of the PPAs with MEC I and MEC II. The reduction in the current risks would represent a risk management benefit of the MIP Agreement. In addition, the Department notes that Xcel's response to Office of Attorney Generation Information Request No. 47 stated that:

> No Facility Lenders exist for either MEC I or MEC II. Southern Power has financed its ownership of MEC I and MEC II using its balance sheet.

Thus, the Department concludes that the incremental financial risks posed by the MIP Agreement are minimal.

b. Operational Risks

Typically PPAs entail operational risks, which are the risks that the projects will not be built and/or operated as expected. These risks include a complete or partial shutdown of a generating facility due to technical problems. In the case of a shutdown, once again Xcel may face the need to find replacement capacity and energy. This analysis is confined to the incremental impact of the MIP Agreement on the operational risks associated with MEC I and MEC II.

First, the Petition at page 15 notes that Xcel was able to obtain a purchase price reduction in the event the MEC expansion does not attain commercial operation by June 1, 2019 (assuming state regulatory approvals have been obtained).[33] Second, as discussed in the Petition at page 18, acquisition of MEC means that Xcel would also acquire the interconnection rights. The Department agrees with Xcel that interconnection rights are a valuable operational commodity, assuming that the Xcel-owned MEC operates for a duration longer than the current PPAs or that the rights can be used by a different generator at the same site. Third, the Department notes the various risk mitigation measures discussed in the Petition at pages 19-20.

[33] The Petition states that Xcel would pass on any savings associated with the purchase price reduction to customers.

Overall, the Department concludes that the incremental operational risks posed by the MIP Agreement are minimal.

c. Summary Regarding Risks

The Department concludes that the MIP Agreement presents minimal, incremental risks.

D. RESPONSE TO COMMISSION NOTICE

1. Is the purchase proposal prudent and in the public interest?

At this time there is insufficient resource planning analysis to determine whether the Company's system has a need for additional resources of the size, type, and timing proposed by Xcel in this proceeding.

2. Are the assumptions/inputs for the cost/benefit analysis reasonable?

Regarding the Company's Strategist analysis, the Department concluded above that the assumptions/inputs are not reasonable. The Department intends to address the Company's reply in supplemental comments.

3. Should Xcel be allowed to recover the difference between the 2019 revenue requirement and the revenues already in base rates?

The Department discusses this issue in more detail above in Section B Review of Cost Recovery and Accounting Issues, Part 1. 2019 Revenue Requirement True-up. The Department concluded that a true-up or rider recovery of capacity/capital costs and O&M costs of a gas facility is not allowed by Minnesota law, was not allowed for Minnesota Power in Docket Nos. E015/AI-17-568 and E015/RP-15-690, Xcel is subject to a rate case settlement through 2019, and Xcel will have an opportunity to request cost recovery in its upcoming rate case. Thus, the Department recommends that the Commission deny Xcel's rate recovery true-up for 2019 revenue requirements.

4. How should cost recovery be effected?

The Department discusses this issue in more detail above in Section B. Review of Cost Recovery and Accounting Issues, Part 1. 2019 Revenue Requirement True-up. The Department concluded that if the MEC I and MEC II transaction is approved Xcel will be able to seek rate recovery in its upcoming rate case, expected to be proposed as a multi-year rate plan (MYRP), starting in 2020 and the Department and interested parties will likely use the Commission's order in this proceeding to ensure that rate recovery for MEC I and MEC II is reasonable.

5. Are any rule variances Required?

The Department discusses this issue in more detail above in Section A 3. Informational Requirements. The Department concluded that, since the proposed transaction does not involve the issuance of securities, the Department agrees with Xcel's analysis. Therefore, the Department recommends that the Commission approve a variance to Minnesota Rules 7825.1800, subp. B to allow Xcel to not provide the information set forth in Minnesota Rules 7825.1400, items (A) to (J).

Additionally, as discussed in more detail above in Section B. Review of Cost Recovery and Accounting Issues, Part 1. 2019 Revenue Requirement True-up, the Department concluded that Xcel's waiver request to allow a true-up of 2019 revenue requirements (capital costs and O&M costs for the MEC I & MEC II gas plants) through the FCA is not appropriate. Costs and revenues allowed through the FCA are defined in Minnesota Rules 7825.2400 – 7825.2600; the rules do not allow recovery of capacity/capital costs or O&M costs through the FCA. Rider recovery was not allowed in Minnesota Power's Energy*Forward* Resource Package proceeding—specifically, the costs associated with the NTEC gas plant as discussed above.

6. How will the transaction impact the 2019 Capital True-Up filing?

The Department notes that since Xcel had a purchase power agreement for MEC I and MEC II, which resulted in energy costs that are allowed to be recovered through the FCA and capacity costs that were included as expenses in base rates in Xcel's last rate case (which was a MYRP). MEC I and MEC II capacity costs were included in the MYRP as shown in Heuer Direct Testimony on Schedule 13 and as shown on Xcel's Attachment H, under Current Base Rate Recovery. Since MEC I and MEC II were not owned by Xcel and were not included in Xcel's capital costs/rate base for the MYRP, the Department does not consider it reasonable to include MEC I and MEC II in the Capital True-Up filing for 2019.

7. How will the transaction impact Xcel's capital structure?

This issue is addressed in the Department's December 24, 2018 comments in Docket No. E,G002/S-18-654. The Department's comments concluded that "the Company's revised requested total capitalization and its revised contingency are reasonable if its petition for acquiring MEC I and MEC II is approved by the Commission and the in-service date commences sometime during 2019."

Specifically, the Department's December 24, 2018 comments on page 4 show that the Company's revised 2019 capital structure as a result of the assumed MEC I and MEC II purchase did not change the Company's common equity percentage, only increased short-term debt by 0.8 percent and decreased long-term debt by 0.8 percent.

8. How do MEC I and MEC II useful lives fit with Xcel's stated goal to be carbon-free by 2050?

The Department did not review how the proposed purchase of MEC fits into the Company's goals, in part since Xcel's IRP analysis for this proceeding was not reasonable for such purposes. Moreover, acquisition of a resource doesn't necessarily determine its future, as many factors change over time. Xcel can set certain goals, such as its carbon-free goal, and attempt to achieve them how the Company deems appropriate. However, the Commission need not consider Xcel's EPS goal when establishing rates.

The purpose of the Department's analyses is to determine if the Company's proposal fits with the requirements of Minnesota Statutes and Minnesota Rules and also review how the proposal addresses the policy goals of the state of Minnesota.

9. If Xcel becomes carbon-free by 2050, should ratepayers be liable for any resulting MEC I and MEC II related stranded costs?

Whether ratepayers should be liable for any MEC-related stranded costs should be determined at the time any costs become stranded, if such a result occurs. The decision should be based upon whether the Company acted in a reasonable manner and any other requirements of Minnesota Statutes and Minnesota Rules that are applicable. To that end, the Department notes that Xcel has yet to demonstrate that its proposal is reasonable.

If Xcel is able to show that its proposed acquisition is reasonable, the Department notes that Minnesota Statutes § 216B.16 subd. 6 states that "[i]f the commission orders a generating facility to terminate its operations before the end of the facility's physical life in order to comply with a specific state or federal energy statute or policy, the commission may allow the public utility to recover any positive net book value of the facility as determined by the commission."

10. Should approval be subject to any conditions?

At this time the Department concludes that there is insufficient evidence to approve the proposal and the Department will review any additional evidence provide by the Company in reply comments. However, the Department notes that, if the Commission determines to approve the proposal, the following recommendations are relevant:

- The Department recommends that the Commission deny Xcel's request for rate recovery true-up for 2019 revenue requirements.
- The Department considers the accounting and ratemaking for the Plant Materials and Operating Supplies (turbine blades) and Prepayments (water supply agreement) to be reasonable.
- The Department recommends that the Commission deny cost recovery from retail ratepayers of the $450,000 in transaction costs.

- The Department recommends that the **[TRADE SECRET HAS BEEN EXCISED]** be recorded and reflected in the NBV, thereby reducing Xcel's estimated $541 million NBV by the same amount. Additionally, the Department recommends that Xcel be required to record and reflect additional depreciation expense of approximately **[TRADE SECRET HAS BEEN EXCISED]** for the period between the June 1, 2019 purchase date and the inclusion of MEC in its next rate case which is likely to be January 1, 2020, thereby reducing Xcel's estimated $541 million NBV by the same amount.
- The Department recommends that the $96.194 million acquisition adjustment be denied.
- Based on the Department's review of the comparison between owning MEC or continuing the PPAs, the present value of the revenue requirements over the life of the MEC plants are similar. However, there are some significant costs risks that would result from the purchase, including:
  - decommissioning would be the responsibility of Xcel and its ratepayers;
  - plant outages and equipment failures would be the responsibility of Xcel and its ratepayers;
  - risk of higher property taxes would shift to Xcel and its ratepayers; and
  - risk of higher O&M expenses would shift to Xcel and its ratepayers, thus
  - Xcel has not shown clear benefits of ownership compared to continuing with the PPAs.

11. What action should the Commission take regarding the request to transfer the site permit in this docket?

As noted above, these comments do not address the Company's request to transfer the site permit.

12. Are there other issues or concerns related to this matter?

The Department does not have any other issues or concerns at this time. However, as noted above the Department intends to provide supplemental comments in this proceeding.

III. DEPARTMENT RECOMMENDATION

The Department recommends that the Commission approve a variance to Minnesota Rules 7825.1800, subp. B to allow Xcel to not provide the information set forth in Minnesota Rules 7825.1400, items (A) through (J).

At this time, the Department recommends that the Commission take no action on the Company's requests to approve the acquisition of Southern's MEC I and MEC II property, under Minnesota Statutes § 216B.50, as Xcel has not shown its proposal to be reasonable.

However, if the Commission approves the proposal, the following recommendations are relevant:

- The Department recommends that the Commission deny Xcel's request for rate recovery true-up for 2019 revenue requirements.
- The Department considers the accounting and ratemaking for the Plant Materials and Operating Supplies (turbine blades) and Prepayments (water supply agreement) to be reasonable.
- The Department recommends that the Commission deny cost recovery from retail ratepayers of the $450,000 in transaction costs.
- The Department recommends that the **[TRADE SECRET HAS BEEN EXCISED]** be recorded and reflected in the NBV, thereby reducing Xcel's estimated $541 million NBV by the same amount. Additionally, Xcel should be required to record and reflect additional depreciation expense of approximately **[TRADE SECRET HAS BEEN EXCISED]** for the period between the June 1, 2019 purchase date and the inclusion of MEC in its next rate case which is likely to be January 1, 2020, thereby reducing Xcel's estimated $541 million NBV by the same amount.
- The Department recommends that the $96.194 million acquisition adjustment be denied.
- Based on the Department's review of the revenue requirements comparison between ownership and continuing under the PPAs, the present value amounts over the life of the MEC plants are similar. However, there are some significant costs risks resulting from ownership, including:
  - decommissioning would be the responsibility of Xcel and its ratepayers;
  - plant outages and equipment failures would be the responsibility of Xcel and its ratepayers;
  - risk of higher property taxes would shift to Xcel and its ratepayers; and
  - risk of higher O&M expenses would shift to Xcel and its ratepayers; thus
  - Xcel has not shown clear benefits of ownership compared to a PPA arrangement.

/ja

Docket No. E002/M-18-702

Attachment 1

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Xcel Energy
Docket No.: E002/M-18-702
Response To: MN Department of Commerce — Information Request No. 2
Requestor: Nancy Campbell, Mark Johnson, Steve Rakow
Date Received: December 13, 2018

Question:
Topic: Journal Entries - Prepayments
Reference(s): Attachment I of Xcel's petition

(a) Please provide a breakout of the $9 million in Prepayments, including the water supply agreement, estimated to be paid to Southern Power.

(b) What accounts will the $9 in Prepayments be closed out to on Xcel's books and what is the expected ratemaking treatment? Please explain your response.

Response:
(a) The $9 million estimated prepaid value is entirely attributed to the prepaid water expense associated with the water supply agreement with the City of Mankato. As of December 2017, Southern Power carried a deferred value of that prepaid expense at $8.8 million and a current value of $711k. NSPM will assume the value of that prepaid expense upon closing of the transaction, and its value is included in the $650 million purchase price.

(b) The $9 million estimated prepaid value will be recorded to account 165 (Prepayments). The final balance will be amortized based on the term of the water supply agreement to account 548 {Generation Expenses} which we would propose to be included in our annual revenue requirement. We would propose to include the unamortized prepayment in rate base using the actual thirteen-month average balance for the test year.

Preparer: Benj Halama
Title: Interim Director
Department: Revenue Requirements North
Telephone: 612-330-5703
Date: January 3, 2019

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Xcel Energy		
Docket No.:	E002/M-18-702	
Response To:	MN Department of Commerce	Information Request No. 3
Requestor:	Nancy Campbell, Mark Johnson, Steve Rakow	
Date Received:	December 13, 2018	

Question:
Topic: Journal Entries – Transaction Costs
Reference(s): Attachment I of Xcel's petition

(a) Please provide a detailed breakout and explanation for the $450,000 in transaction costs.

(b) Using the detailed breakout of transactions costs, please provide support to show that these types of costs are not already included in Xcel's base rates.

(c) Please explain and provide support for why these transaction costs should be allowed to be capitalized and included in rate base.

Response:

(a) The $450k transaction costs represent an estimate of the legal and regulatory filing fees associated with transaction. We estimated the $450k number based on:

- $234k in outside counsel fees billed as of 11/20/2018;
- An estimated $50k in additional outside counsel fees to complete the transaction legal work after 11/20/18;
- $125k in Hart-Scott-Rodino filing fees to be paid to the Federal Trade Commission; and
- An additional $41k for support and fees associated with closing the transaction.

(b) The budget for the 2016 test year in our rate case was developed in mid-2015 — well before we commenced discussions regarding the acquisition of the Mankato facility. We therefore did not account for the transaction or the associated legal fees when developing the 2016 test-year budget.

Moreover, that rate case test-year budget included a total of $3,985,759.86 in legal fees and, of that total, only $5,000 was budgeted for outside legal services for the acquisition of assets, of which this transaction would fall into.

Attachment A breaks down the test-year budget of $3,985,759.86 into separate categories of legal services that comprise the total and shows the $5,000 budget in the category titled "Purchase Power Other." Given the timing and components of our test-year budget, we believe it is reasonable to conclude that $507,000 budgeted for the legal fees associated with the Mankato acquisition are incremental to the legal fees already built into the Company's base rates.

(c) The legal services provided in this matter pertain to the exploration, negotiation, and additional considerations related to the acquisition of this asset. It is therefore appropriate to capitalize these costs as part of the overall asset acquisition.

Preparer:	Benj Halama
Title:	Interim Director
Department:	Revenue Requirements North
Telephone:	612-330-5703
Date:	January 3, 2019

Northern States Power Company

NSPM O&M Expenses
General Counsel Business Area
Expense Type 713100-Consulting/Prof Svcs-Legal

Detailed Expenses by FERC Cateogry

506-Misc Steam Pwr Exp	$	80,000
524-Nuclear Power Misc Exp	$	321,000
539-Hydro Oper Misc Gen Exp	$	5,000
549-Oth Oper Misc Gen Exp	$	175,000
557-Purchased Power Other (1)	$	5,000
566-Trans Oper Misc Exp	$	37,000
923-A&G Outside Services	$	3,362,760
Total	**$**	**3,985,760**

(1) Legal expenses related to purchase power agreemens (similar to Benson work) would be booked in the FERC 557.

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Xcel Energy — Information Request No. 44

Docket No.: IP6949,E002/PA-18-702
Response To: Office of Attorney General
Requestor: Ryan P. Barlow
Date Received: January 14, 2019

Question:
Re: Petition, Page 45

Petition states: "The net book value of MEC's property, plant and equipment (including construction work in progress) is $495 million as of September 30, 2018 based on Financial Statements provided by Southern Power. Taking into consideration estimated remaining project costs associated with MEC II and additional assets to be acquired, the estimated net book value of the assets to be acquired at May 31, 2019 is $541 million."

Provide all of the information supporting the $495 million and $541 million assertions, including the referenced financial statements from Southern Power.

Response:

Please see Attachment A and Attachment B to this response.

Please note portions of this response and the attachments are marked as "Non-Public," as they contain information we consider to be trade secret data as defined by Minn. Stat. §13.37(1)(b). The information derives an independent economic value from not being generally known or readily ascertainable by others who could obtain a financial advantage from its use. Based on its economic value, the Company maintains this information as trade secret.

The Attachments to this response are marked as "Not-Public" in their entirety. Pursuant to Minn. Rule 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material:** Balance sheet information related to MEC I and MEC II.
2. **Authors:** Southern Power Company and Xcel Energy

3. **Importance:** The information contained on the spreadsheet attachments represents the book and records of Southern Power Company related to net book value of MEC I and MEC II. That information was utilized by Xcel Energy to develop projections related to the future book value of the MEC facility. In both cases, the information on the spreadsheets is sensitive in that it includes certain costs related to Southern Power's investment in Mankato as well as overall book value of those assets which could be utilized by third parties in the event a transaction with NSPM does not close and Southern proceeds with an alternative disposition.
4. **Date the Information was Prepared:** Q4 2018

Preparer: Aaron Hansen
Title: Manager
Department: Capital Asset Accounting
Telephone: 612-330-6854
Date: January 25, 2019

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The Attachments to this response are marked as "Not-Public" in their entirety. Pursuant to Minn. Rule 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material:** Balance sheet information related to MEC I and MEC II.
2. **Authors:** Southern Power Company and Xcel Energy
3. **Importance:** The information contained on the spreadsheet attachments represents the book and records of Southern Power Company related to net book value of MEC I and MEC II. That information was utilized by Xcel Energy to develop projections related to the future book value of the MEC facility. In both cases, the information on the spreadsheets is sensitive in that it includes certain costs related to Southern Power's investment in Mankato as well as overall book value of those assets which could be utilized by third parties in the event a transaction with NSPM does not close and Southern proceeds with an alternative disposition.
4. **Date the Information was Prepared:** Q4 2018

[TRADE SECRET BEGINS

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Xcel Energy			
Docket No.:	E002/M-18-702		
Response To:	MN Department of Commerce	Information Request No.	4
Requestor:	Nancy Campbell, Mark Johnson, Steve Rakow		
Date Received:	December 13, 2018		

Question:

Topic: Journal Entries – Acquisition Adjustment
Reference(s): Attachment I of Xcel's petition

(a) Please provide the amortization period for the $96.194 million acquisition adjustment and show where this is reflected in Attachment G – Revenue Requirements, of Xcel's petition.

(b) Please provide support for why ratepayers should pay for this $96.194 million acquisition adjustment, including identifying offsetting benefits for ratepayers.

(c) Please provide citations to cases where acquisition adjustment recovery was allowed for plants already devoted to public service.

Response:

(a) As referenced in Xcel Energy's petition (page 45), the acquisition adjustment is requested to be included in rate base with a full return over the same useful life as the plant investment. Within Attachment G – Revenue Requirements, the entire acquisition cost, including the acquisition adjustment, is reflected in the purchase price of MEC I and MEC II and is amortized over the estimated useful life of the plant, which is 2046 and 2054 for MEC I and MEC II, respectively.

~~(b)~~ The purchase price adjustment represents an estimate of the purchase price in excess of the net book value of the acquired assets. The net book value reflects the asset carrying value per Southern Power's accounting records and is not representative of the fair market value of the plant. As our analysis shows, Xcel Energy's customers will realize savings from the acquisition at the purchase price, including the acquisition adjustment, when compared to continuing with the PPAs and securing replacement power post PPA.

(c) The Uniform System of Accounts of the Federal Energy Regulatory Commission requires any difference between the original plant cost and the cost to acquire to be recorded as an acquisition adjustment (*See* Title 18, Chapter I, Subchapter C, Part 101).

An example of when an acquisition adjustment was allowed occurred in December 2010, with PSCo's purchase of Blue Spruce Energy Center and Rocky Mountain Energy Center from Calpine Development Holdings, Inc. and Riverside Energy Center LLC (FERC Docket Nos. EC10-71-000; AC11-99-000).

Preparer:	Aaron Hansen
Title:	Manager
Department:	Capital Asset Accounting
Telephone:	612-330-6854
Date:	January 3, 2019

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Xcel Energy		
Docket No.:	E002/M-18-702	
Response To:	MN Department of Commerce	Information Request No. 7
Requestor:	Nancy Campbell, Mark Johnson, Steve Rakow	
Date Received:	December 13, 2018	

<u>Question:</u>
Topic: Incremental Revenue Requirement Impact of MEC Ownership
Reference(s): Table 8 of Xcel's petition

(a) Please provide supporting calculations for "Fixed Savings of Mankato PPA".

(b) Please provide a breakout of individual items that make up the "VOM/Fuel/Market Costs Savings" and explain for each item why this is a benefit or savings as a result of changing from Purchase Power Agreement (PPA) to Revenue Requirement ownership.

(c) Please explain why the "VOM/Fuel/Market Costs Savings" should be included in the incremental revenue requirement impact, since these appear to be broader market savings using Strategist.

(d) Please identify any higher costs as a result of Xcel owning and using a revenue requirement method compared to the current PPA method.

(e) Please provide the incremental revenue requirements for the PPA method vs the revenue requirement ownership method for the **entire life of MEC I & MEC II** (similar to the first two lines of Table 8 – which uses Attachment G for Revenue Requirements). For both the PPA and revenue requirements methods, please assume full use of MEC 1 & MEC II for life of the plants to allow for an apple to apple comparison of the PPA vs revenue requirement methods. The Department notes that for the PPA assumptions the Company could consider using Schedule 13 in Heuer Direct in Docket E002/GR-15-826 to determine an inflation rate for extending the PPA for the full life of MEC I & II. Please provide actual information from the existing MEC 1 & MEC II PPAs and assumed data after the current MEC 1 & MEC II PPAs terminates on separate lines.

(f) Does the incremental revenue requirements requested in part (e) above show a net benefit over the life of MEC I & II, as a result of the revenue requirement – ownership method?

Response:

(a) The "Fixed Savings of Mankato PPA" is the avoided capacity payments due to the termination of the PPAs. For 2019, it is assumed 5 months of capacity payments for MEC I would be incurred under the PPA with Company ownership beginning in June 2019. The fixed savings are shown in the table below:

	2019	2020	2021	2022	2023	2024
MEC I PPA through May 2019	15.83	0.00	0.00	0.00	0.00	0.00
Less: Capacity Payment-MEC I and II PPAs	(54.75)	(67.27)	(68.24)	(69.22)	(70.19)	(71.21)
Fixed Savings of Mankato PPA	(38.92)	(67.27)	(68.24)	(69.22)	(70.19)	(71.21)
Rounded	(39)	(67)	(68)	(69)	(70)	(71)

(b) Please see Attachment A to this response which provide the breakdown of individual cost categories through 2057 on the "Breakdown of Savings" tab. The table below provides a brief summary of the impact of each category:

Cost/(Savings) Category	Explanation
Capital Cost of Mankato Purchase	Costs expected to be incurred due to the purchases of MEC. This amount corresponding to Line 21 on Attachment G.
Fixed Savings of Mankato PPA	Fixed PPA costs avoided due to the termination of the existing PPAs
Fixed Cost/Expansion Plan Cost/(Savings)	Saving due to avoid capacity costs. These benefits are due to the longer lives of the resources under the ownership option as compared to the current PPA terms.
VOM Cost/(Savings)	Some variable O&M costs are avoided due to the structure of the PPA compared to expected costs under company ownership.
Fuel Cost/(Savings)	Fuel cost increase slightly due to higher reliance on MEC to offset market purchases or make sales.
Market Cost/(Savings)	Market savings increase due to increase energy output from MEC under ownership and avoided market purchases or increased sales.
CO_2 Cost/(Savings)	CO_2 costs reflect the regulatory cost of CO_2 after 2024. There are slightly higher CO_2 costs due to the increased energy output from MEC.
Externalities Cost/(Savings)	Until 2024, CO_2 costs are shown as an externality. Externality savings in the near term are due to the higher energy output of MEC expected under ownership.
PPA Starts/Own Start Fuel Cost/(Savings)	We expect start costs to be lower under ownership compared to the start costs under the existing PPAs.

Please note that for each category, the impacts of ownership are compared to the existing PPAs during each PPA term, which expire in 2026 and 2039. Comparison of the impacts of ownership of MEC after those date are based on the generic resources selected by the Strategist model.

(c) The savings associated with Xcel Energy's purchase of the Mankato Energy Center—including the "VOM/Fuel/Market Costs Savings" identified in the Company's petition—will be realized on the NSP system and passed on to our customers. As benefits of the transaction, they are appropriately incorporated into our analysis.

Table 8 from our petition provides a summary of the incremental impacts to system costs of the ownership of MEC compared to the existing PPAs. Attachment A provides the detailed breakdown of the system impacts.

(d) Attachment A provides the detailed breakdown of costs. The cost deltas between ownership and PPAs are shown graphically in Figure 1 and 2 of the petition.

Xcel's ownership of Mankato Energy Center will result in higher capital costs, higher fuel costs, and an increase in CO2 regulatory costs due to the increased output of the plant.

(e) We conducted a Strategist run in which the Mankato I and II PPAs were extended through the life of the plants; through June 2046 and March 2054. We assumed that the operations of each plant remain the same as the current contracts, and escalated the costs by 2% per year after the PPAs expiration dates in 2026 and 2039. The escalated fixed PPA payments are shown in the "Fixed Savings of Mankato PPA" line on the "Own vs. MEC PPA Ext" tab of Attachment A.

A summary of the incremental revenue requirements of owning Mankato Energy Center in comparison to an extension of the Mankato Energy Center PPAs is shown below. Please refer to the "Own vs. MEC PPA Ext." tab of Attachment A for an annual breakdown.

Incremental RR Impact

	2018 PVRR
Capital Cost of Mankato Purchase	915
Fixed Savings of Mankato PPA	(981)
Fixed Cost/Expansion Plan Cost/(Savings)	(84)
VOM Cost/(Savings)	(44)
Coal	(2)
Gas	(31)
Fuel Cost/(Savings)	(61)
Coal	(26)
Gas	(33)
Other	(2)
Market Cost/(Savings)	150
CO2 Cost/(Savings)	(34)
Externalities Cost/(Savings)	(63)
PPA Starts/Own Start Fuel Cost/(Savings)	(52)
Total Cost/(Savings)	(255)

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Incremental RR Impact High Renewables

	2018 PVRR
Capital Cost of Mankato Purchase	915
Fixed Savings of Mankato PPA	(571)
Fixed Cost/Expansion Plan Cost/(Savings)	(364)
VOM Cost/(Savings)	(32)
Coal	(3)
Gas	(29)
Fuel Cost/(Savings)	28
Coal	(41)
Gas	72
Other	(2)
Market Cost/(Savings)	(28)
CO2 Cost/(Savings)	5
Externalities Cost/(Savings)	(65)
PPA Starts/Own Start Fuel Cost/(Savings)	(48)
Total Cost/(Savings)	(162)

(f) Extending the PPAs for the entire life of MEC I & MEC II results in a net cost of $255MM in comparison to the MEC ownership case. The high renewables scenario with the PPA extensions results in a net cost of $162MM when compared to the MEC Ownership option with the high renewable tail.

Attachment A provided with the Not Public version of this response contain data classified as trade secret pursuant to Minn. Stat. §13.37 and are marked as "Not Public" in their entirety. Pursuant to Minn. R. 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material**: Annual cost impact outputs of Strategist modeling.
2. **Authors:** The model was prepared by the Resource Planning Analytics group with inputs provided by multiple areas across the Company.
3. **Importance:** The model contains competitively sensitive data related to PPAs and project costs.
4. **Date the Information was Prepared**: The model was prepared during the fourth quarter of 2018.

Preparer: Jon Landrum
Title: Manager
Department: Resource Planning Analytics
Telephone: 303-571-2765
Date: January 3, 2019

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Attachment A provided with the Not Public version of this response contain data classified as trade secret pursuant to Minn. Stat. §13.37 and are marked as "Not Public" in their entirety. Pursuant to Minn. R. 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material**: Annual cost impact outputs of Strategist modeling.
2. **Authors:** The model was prepared by the Resource Planning Analytics group with inputs provided by multiple areas across the Company.
3. **Importance:** The model contains competitively sensitive data related to PPAs and project costs.
4. **Date the Information was Prepared**: The model was prepared during the fourth quarter of 2018.

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Xcel Energy		
Docket No.:	E002/M-18-702	
Response To:	MN Department of Commerce	Information Request No. 8
Requestor:	Nancy Campbell, Mark Johnson, Steve Rakow	
Date Received:	December 13, 2018	

Question:
Topic: Revenue Requirements Assumptions
Reference(s): Attachment G, Revenue Requirements of Xcel's petition

(a) Under the Revenue Requirements tab, on line 13 "O&M Expense" please explain why O&M expense is significantly higher in the years 2028 and 2038.

(b) Under the Depreciation tab, on lines 12 to 38, what is the basis for these plant additions for MEC I?

(c) Under the Depreciation tab, on lines 62 to 96, what is the basis for these plant additions for MEC II?

(d) Under the Inputs and Assumptions tab, please explain why the two lives of the gas plant are different.

(e) Please explain why Reactive Power is a benefit under Xcel ownership and revenue requirement method, compared to Southern Power ownership and PPA method.

(f) Since heat recovery mechanism is connected in MEC I, will the rating or output be limited after MEC I is retired? If yes, please explain if this is factored into Xcel's revenue requirements assumptions.

Response:
(a) The Company's Energy Supply team underwent a robust process to forecast Mankato Energy Center (MEC) ongoing expenditures (O&M and capital). Details supporting those expenditures can be found in the Excel based revenue requirements model in the tab labelled, "ES O&M|Capex". The increase in O&M expense in the years 2028 and 2038 is primarily related to turbine and

generator inspections which are scheduled to occur every 10 years and do not involve replacement of major parts.

(b) Ongoing capital expenditures for MEC I are largely associated with combustion inspections, hot gas path inspections and generator rewinds that involve replacement of major parts. Details supporting the amounts and timing of such expenditures can be found in the Excel based revenue requirements model in the tab labelled, "ES O&M|Capex".

(c) Ongoing capital expenditures for MEC II are largely associated with combustion inspections, hot gas path inspections and generator rewinds that involve replacement of major parts. Details supporting the amounts and timing of such expenditures can be found in the Excel based revenue requirements model in the tab labelled, "ES O&M|Capex".

(d) Each combustion turbine is capable of a 40 year life. However, in the case of MEC I and MEC II, consideration was given to the life of the single steam turbine shared by each combustion turbine. Our analysis showed that the costs to extend the steam turbine life an additional 5 years to align with a 40 year expected life of the MEC II combustion turbine outweighed the benefits to our customers.

(e) Upon NSP's ownership of Mankato Energy Center (MEC), the Company expects that it will assume Southern Power's existing MEC reactive power rate in the MISO Tariff for providing reactive power services. As such, NSP customers will benefit from the portion of reactive power payments collected from non-NSP transmission customers. We have reflected the non-NSP payments as a reduction to revenue requirements.

(f) The revenue requirements calculation was designed to treat each unit individually given their different expected lives, maintenance schedule and related expenditures. Revenue requirements associated with the existing MEC I unit cease in 2046 when that units combustion turbine is retired and the facility reverts to a1x1 configuration until MEC II's retirement in 2054.

Preparer:	Stan Dufault
Title:	Manager, Asset Development
Department:	Corporate Development
Telephone:	612-215-4577
Date:	January 3, 2019

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Xcel Energy		Information Request No. 47
Docket No.:	IP6949,E002/PA-18-702	
Response To:	Office of Attorney General	
Requestor:	Ryan P. Barlow	
Date Received:	January 14, 2019	

Question:
Re: Attachment B, page 14 of 123

List each "Facility Lender" including but not limited to Xcel Energy and Northern States Power. Provide the amount of "Facility Debt" provided by each Facility Lender.

Response:
No Facility Lenders exist for either MEC I or MEC II. Southern Power has financed its ownership of MEC I and MEC II using its balance sheet.

Preparer:	Jerry Dittman
Title:	Manager, Business Development
Department:	Corporate Development
Telephone:	612-215-4568
Date:	January 25, 2019

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Xcel Energy		Information Request No. 15
Docket No.:	IP6949,E002/PA-18-702	
Response To:	Office of Attorney General	
Requestor:	Ryan P. Barlow	
Date Received:	January 11, 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 pages 19-20.

Provide all internal reports regarding the operational due diligence the Company conducted.

Provide a summary of all known or potential risks associated with the transaction that the Company identified.

Response:
Please see Attachments A through I.

The following is a list of known and potential operational risks identified in the diligence reports attached to this response:

- Water Supply - The raw water supply demands appear to be sufficient to support peak hourly demand, but the limiting factor resides in the water filtration system during extended fired runs. The current water supply agreement in place with the City of Mankato does not provide for a minimum daily water supply obligation. Southern Power is in the process of negotiating certain amendments to the water supply agreement that will provide certainty regarding the long term supply of adequate water to the facility as well as improvements to the water filtration system.
- Steam Turbine - There have been two last stage blade (L-0 blade) failures of the Toshiba steam turbine in the Toshiba fleet. Southern Power has procured a set of replacement L-0 blades for inventory in the event of a failure in operation or replacement upon inspection due to the long lead time necessary to fabricate a

replacement blade. Those replacement blades are included in the transaction. This situation represents a low to moderation risk that is mitigated with immediate availability of replacement blades provided that the recommended blade inspections are followed; the L-0 blades are replaced if indicated and low load operation is minimized to the extent practicable.

- Gas Turbine Reliability - The cost model has been prepared by assuming the CTs will be reliable through the Siemens LTPA term. There is some risk of decreasing reliability /increasing cost as the units age which is partially mitigated by the LTPA agreement.
- Cold Weather Operation - The facility design will require more maintenance and operations labor and risk than the existing NSP combined cycle facilities. It will be similar to the PSCo Rocky Mountain Energy Center.
    - No enclosed staircase to HRSG Drum level: Significant safety risk in winter operation.
    - No hoists or overhead cranes over equipment. Increased cost for mobile crane use rent or own for maintenance and repair activities.
    - No elevator installed. Potential safety risk with extensive stair usage and increased maintenance time and cost.
    - Anhydrous ammonia is used in the SCR system. This is not used on any other Xcel sites in NSP. It poses a safety risk for operation and maintenance. New operating and maintenance policies and procedures will need to be developed.
- There will be significant effort to integrate the existing drawing data and equipment database base into NSP standard.
- Liquid fuel capabilities were not reliably demonstrated by the previous owner (Calpine), and Southern claims to have addressed the problems but has not yet demonstrated liquid fuel capabilities.
- Pipeline alignment sheets for the natural gas and reclaimed water pipelines were not available. This is a minor risk mitigated by the generally recent period of construction of those facilities.
- Minor risk associated with a future assertion that the Property Tax exemption applicable to MEC does not apply to NSPM in the event it is determined construction of the expansion facility is not completed prior to NSMP assuming ownership.

Please note portions of this response and the attachments are marked as "Non-Public," as they contain information we consider to be trade secret data as defined by Minn. Stat. §13.37(1)(b). The information derives an independent economic value from not being generally known or readily ascertainable by others who could obtain a financial advantage from its use. Based on its economic value, the Company maintains this information as trade secret.

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The Attachments to this response are marked as "Not-Public" in their entirety. Pursuant to Minn. Rule 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material:** Diligence reports from multiple internal sources within NSPM.
2. **Authors:** NSPM (multiple individuals).
3. **Importance:** This information reveals objective and subjective information generated by NSPM related to the business operations of Mankato Energy Center and its assets. In the event the transaction with NSPM does not close, Southern Power may wish to sell the plant to a third party, in which case this information could be used by a third party to influence the economic value of the facility. Additionally, disclosure of factual information related to the plant could be utilized by competitors of Southern Power to structure bids that compete with Southern Power in response to future competitive power supply solicitations. Finally, disclosure of this information to Southern Power could damage NSPM's negotiation position in the event a relevant dispute or disagreement occurs under either the PPA's or our purchase and sale agreement.
4. **Date the Information was Prepared:** Q4 2018.

Preparer:	Jerry Dittmann
Title:	Corporate Development Manager
Department:	Corporate Development
Telephone:	651-323-8275
Date:	January 24, 2019

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The Attachments to this response are marked as "Not-Public" in their entirety. Pursuant to Minn. Rule 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material:** Diligence reports from multiple internal sources within NSPM.
2. **Authors:** NSPM (multiple individuals).
3. **Importance:** This information reveals objective and subjective information generated by NSPM related to the business operations of Mankato Energy Center and its assets. In the event the transaction with NSPM does not close, Southern Power may wish to sell the plant to a third party, in which case this information could be used by a third party to influence the economic value of the facility. Additionally, disclosure of factual information related to the plant could be utilized by competitors of Southern Power to structure bids that compete with Southern Power in response to future competitive power supply solicitations. Finally, disclosure of this information to Southern Power could damage NSPM's negotiation position in the event a relevant dispute or disagreement occurs under either the PPA's or our purchase and sale agreement.
4. **Date the Information was Prepared:** Q4 2018.

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Xcel Energy		Information Request No. 25.1
Docket No.:	IP6949,E002/PA-18-702	
Response To:	Office of Attorney General	
Requestor:	Joseph Meyer	
Date Received:	January 28, 2019	

Question:
Re: Response to OAG Information Request 25

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Response:
Attachment A to OAG IR No. 25 is an expense sheet of capital expenditures for Southern Company. As such, major outage expenses are an obligation of the owner of the facility and none of these costs were passed on to our customers.

Preparer:	Jeff Klein
Title:	Manager, Structured Purchases
Department:	Purchased Power
Telephone:	303-571-2732
Date:	February 7, 2019

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Xcel Energy		Information Request No. 35
Docket No.:	IP6949,E002/PA-18-702	
Response To:	Office of Attorney General	
Requestor:	Ryan P. Barlow	
Date Received:	January 14, 2019	

Question:
Re: Petition, Page 19

Petition states: "Second, each of the combustion turbines for MEC I and MEC II are covered by long term parts and service agreements with Siemens (LTPA). The LTPA offers significant long term benefits to the reliable operation of the facility by providing a comprehensive warranty on major equipment for each combustion turbine for 35 years (expires 2051), with Siemens providing parts and service during the term of that contract. Associated with the LTPA is a 10-year extended (prorated) warranty for each combustion turbine generator. Siemens will also have a resident manager on site at the Mankato facility through 2021. The cost of the LTPA has been included in the economic evaluation of our acquisition with risk mitigation value derived from the additional combustion turbine and generator warranties, OEM bulletin implementation, technical support and remote performance monitoring."

In the event that equipment fails after the LTPA or warranty expires, explain who would pay for expenses:

- Under the PPA; and
- Xcel ownership.

Define, Explain and Quantify the "risk mitigation value."

Response:

- In each case (PPA and Company ownership), to the extent any such failure is not covered via alternative coverage, the owner of the facility is responsible for such costs.
- Risk mitigation value relates to the risks assumed by Siemens with respect to their obligations under the LTPA in exchange for payment by the owners of MEC I and MEC II under the LTPA that otherwise will exceed the cost of

parts and service if supplied without the benefit of warranty. That value has not been quantified for this particular transaction, as it requires actuarial expertise in terms of determining the probability of failure, cost of repair and ability to socialize those costs across a population of facilities with similar warranty coverage. Experience in the operation of other generating facilities in our service territories has generally resulted in the view that the additional cost of LTPA warranties will by their nature levelize the total expenditures on parts over the lifetime of a plant (via the periodic payment structure of those contracts), and the lower initial cost of non-warrantied service parts is offset by occasional failures or unexpected replacements *when taken in the aggregate across a fleet of operating assets*. Presumably the risk mitigation value equates to the excess cost of service and parts provided under the LTPA vs. a base case where no warranty exists and taken over the life of the project. While it can vary on a case by case basis, there is additional value from an operations perspective in incenting parts and service providers to maintain quality and performance in their product offerings with warranty coverage obligations vs. demanding strictly the lowest price and potentially driving down quality and performance.

Preparer:	Jerry Dittman
Title:	Manager, Business Development
Department:	Corporate Development
Telephone:	612-215-4568
Date:	January 25, 2019

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Xcel Energy		Information Request No. 74
Docket No.:	IP6949,E002/PA-18-702	
Response To:	Office of Attorney General	
Requestor:	Ryan P. Barlow	
Date Received:	January 14, 2019	

Question:
Re: Attachment C, Page 66 of 143, Section 20.3(C)

Attachment C states: "Upon permanent cessation of generation from the Facility, Seller shall decommission the Facility, remove the Facility and remediate the Site as, if and when required by Applicable Laws."

Under the PPA, explain who would pay for all costs described under 20.3(C), including decommissioning and removing the Facility and remediating the Site.

Response:
Seller would pay for all costs described under 20.3(C), including decommissioning, removing the Facility, and remediating the Site.

Preparer:	Jeff Klein
Title:	Manager, Structured Purchases
Department:	Purchased Power
Telephone:	303-571-2732
Date:	January 25, 2019

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Xcel Energy		
Docket No.:	E002/M-18-702	
Response To:	MN Department of Commerce	Information Request No. 1
Requestor:	Steve Rakow	
Date Received:	November 15, 2018	

Question:
Northern States Power Company, doing business as Xcel Energy's November 6, 2018 Information Letter regarding a forthcoming petition requesting approval of the acquisition from Southern Company of the Mankato Energy Center indicates the Company may provide detailed cost effectiveness/Strategist analysis discussion. If the Company includes Strategist analysis in the forthcoming petition, please provide the Department at the time of filing:

a. A *.FSV file for the reference case used by Xcel;
b. macro files (*.INP) which adjust the base case (*. FSV file) to implement the sensitivities explored by Xcel; and
c. any post processing files necessary to translate Strategist outputs into the information presented in the forthcoming petition.

Response:
The Company will supplement this response at time of filing to provide the Department with the requested files.

Supplement:
The requested files can be found on the CD being delivered to the Department on November 27, 2018.

Preparer:	Amber Hedlund	
Title:	Case Specialist	
Department:	Regulatory Affairs	
Telephone:	612.337.2268	
Date:	November 26, 2018	**Supplemented**: November 27, 2018

CERTIFICATE OF SERVICE

I, Sharon Ferguson, hereby certify that I have this day, served copies of the following document on the attached list of persons by electronic filing, certified mail, e-mail, or by depositing a true and correct copy thereof properly enveloped with postage paid in the United States Mail at St. Paul, Minnesota.

Minnesota Department of Commerce
Public Comments

Docket No. IP6949, E002/PA-18-702

Dated this 5th day of March 2019

/s/Sharon Ferguson

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Sarah	Johnson Phillips	sarah.phillips@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_18-702_Official Service List

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