division of energy resources
Minnesota Department of Commerce

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June 13, 2012

Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 300
St. Paul, Minnesota 55101

RE: **Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. E002/M-12-50

Dear Dr. Haar:

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

> Xcel's Petition for approval of 2012 Transmission Cost Recovery (TCR), Project Eligibility, TCR Rate Factors, and 2011 True-up.

The petition was filed on January 13, 2012 by:

> Mark Suel
> Regulatory Case Specialist
> Xcel Energy
> 414 Nicollet Mall
> Minneapolis, Minnesota 55401

The Department recommends that Xcel provide additional information in reply comments; the Department will provide additional comments subsequently. The Department is available to answer any questions the Commission may have.

Sincerely,

/s/ MARK A. JOHNSON
Financial Analyst

/s/ CHRISTOPHER SHAW
Rates Analyst

MAJ/CS/ja
Attachment

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

COMMENTS OF THE
MINNESOTA DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

DOCKET NO. E002/M-12-50

I. BACKGROUND

On August 1, 2006, Northern States Power d/b/a Xcel Energy (Xcel or the Company) filed a petition requesting approval of a Transmission Cost Recovery (TCR) Rider. The TCR Rider is intended to replace the existing Renewable Cost Recovery (RCR) Rider and reflect changes required by Minn. Stat. §216B.16, subd. 7(b) adopted during the 2005 legislative session.

On November 20, 2006, the Minnesota Public Utilities Commission (Commission) issued its Order Approving Transmission Cost Recovery Rider in Docket No. E002/M-06-1103 approving Xcel's proposed tariff for the TCR Rider with the condition that Xcel must maintain separate tracker accounts for projects approved under the renewable cost recovery statute, and those approved under the transmission cost recovery statute.

On January 13, 2012, Xcel filed its petition for approval of 2012 Transmission Cost Recovery (TCR), Project Eligibility, TCR Rate Factors, and 2011 True-up (2012 TCR filing). Xcel's previous TCR filing was approved by the Commission on October 21, 2011 in Docket No. E002/M-10-1064.

II. SUMMARY OF FILING

In previous Orders, the Commission approved recovery of a number of projects under the Transmission Cost Recovery Statute (TCR Statute, Minn. Stat. §216B.16, subd. 7), as well as projects eligible for recovery under the Renewable Cost Recovery Statute (RCR Statute, Minn. Stat. §216B.1645) and the Greenhouse Gas Infrastructure Statute (Minn. Stat. §216B. 1637).

The Commission also approved recovery of Midwest Independent System Operator (MISO) Regional Expansion Criteria and Benefits (RECB) revenues and costs invoiced to the Company by MISO.

In the current petition, Xcel seeks cost recovery for a number of projects under the TCR and RCR Statutes. Xcel does not seek cost recovery for any projects under the Greenhouse Gas Infrastructure Statute. Xcel also proposes to recover the revenue requirements associated with net RECB (Schedule 26) charges. In addition, Xcel proposes to remove revenue requirements associated with project costs included in base rates, Buffalo Ridge Restoration retirement costs, and 2011 true-up costs. A summary of Xcel's proposed 2012 TCR revenue requirements is provided in the table below:

Project Number	Project	Estimated 2012 Revenue Requirement
8	Chisago Apple River	$4,090,362
11	CapX – Fargo	$8,884,268
12	CapX – Brookings	$6,458,017
13	CapX - La Crosse 1	$302,726
13	CapX - La Crosse 2	$1,818,969
14	Capx – Bemidji	$2,685,218
17	Pleasant Valley-Byron	$355,590
18	Buffalo Ridge Restoration	$3,850,813
19	Glencoe-Waconia	$688,487
	Net RECB Rev. Requirements	$1,420,784
	Rev. Requirements in Base Rates	($179,322)
	Rev. Requirement Impact of Project 18 Retirements	($349,625)
	2011 TCR True-Up Carryover	($432,253)
	Total Revenue Requirements	$29,594,035

Starting with the $29,594,035 total revenue requirements for Minnesota for 2012, less the expected revenues collected through March 2012 of $5,389,037, the remaining Minnesota revenue requirements to be recovered through December of 2012 totals $24,204,998.

The Company proposes to allocate the proposed revenue requirements according to the transmission demand and sales allocators set forth in the Company's 2008 electric rate case (Docket No. E002/GR-08-1065). This approach would yield the following TCR rate adjustment factors for 2012:

Customer Group	Rate
Residential	$0.001368/kWh
Commercial Non-Demand	$0.001052/kWh
Street Lighting	$0.000657/kWh
Demand Billed	$0.350/kW

Xcel proposes to charge its residential, commercial non-demand, and street lighting customers using an energy-only rate (per kWh) and its demand-billed customers using a demand rate (per kW).

The monthly bill impact for a residential customer using, on average, about 750 kWh per month would be $1.03 per month, or about $12.30 per year. This amount represents an increase of $0.33 per month or $3.96 per year from the TCR rate factor approved in 2011.[1]

Xcel's proposed TCR rate factors are calculated assuming an effective date of April 1, 2012. Since the Commission was not able to act on this petition in time for rates to become effective April 1, Xcel requests that rate factors be recalculated to recover the 2012 revenue requirements over the remaining months of 2012. The Commission authorized similar treatment in past TCR orders.

III. DOC ANALYSIS

A. STATUTORY REQUIREMENTS

The TCR Statute, Minn. Stat. §216B.16, subd 7b states the following:

> Subd. 7b. **Transmission cost adjustment.**
> (a) Notwithstanding any other provision of this chapter, the commission may approve a tariff mechanism for the automatic annual adjustment of charges for the Minnesota jurisdictional costs of (i) **new** transmission facilities that have been separately filed and reviewed and approved by the commission under section 216B.243 or are certified as a priority project or deemed to be a priority transmission project under section 216B.2425; and (ii) charges incurred by a utility that accrue from other transmission owners' regionally planned transmission projects that have been determined by the Midwest Independent System Operator to benefit the utility, as provided for under a federally approved tariff.

[1] Docket No. E002/M-10-1064.

> (b) Upon filing by a public utility or utilities providing transmission service, the commission may approve, reject, or modify, after notice and comment, a tariff that:
>
> (1) allows the utility to recover on a timely basis the costs net of revenues of facilities approved under section 216B.243 or certified or deemed to be certified under section 216B.2425 or exempt from the requirements of section 216B.243;
>
> (2) allows the charges incurred by a utility that accrue from other transmission owners' regionally planned transmission projects that have been determined by the Midwest Independent System Operator to benefit the utility, as provided for under a federally approved tariff. These charges must be reduced or offset by revenues received by the utility and by amounts the utility charges to other regional transmission owners, to the extent those revenues and charges have not been otherwise offset;
>
> (3) allows a return on investment at the level approved in the utility's last general rate case, unless a different return is found to be consistent with the public interest;
>
> (4) provides a current return on construction work in progress, provided that recovery from Minnesota retail customers for the allowance for funds used during construction is not sought through any other mechanism;
>
> (5) allows for recovery of other expenses if shown to promote a least-cost project option or is otherwise in the public interest;
>
> (6) allocates project costs appropriately between wholesale and retail customers;
>
> (7) provides a mechanism for recovery above cost, if necessary to improve the overall economics of the project or projects or is otherwise in the public interest; and
>
> (8) terminates recovery once costs have been fully recovered or have otherwise been reflected in the utility's general rates. (Emphasis added)

The RCR Statute, Minn. Stat. §216B.1645, subd. 1 states that:

> Upon the petition of a public utility, the Public Utilities Commission shall approve or disapprove power purchase contracts, investments, or expenditures entered into or made by the utility to satisfy the wind and biomass mandates contained in sections 216B.169, 216B.2423, and 216B.2424, and to satisfy the renewable energy objectives and standards set forth in section 216B.1691, including reasonable investments and expenditures made to:

> (1) transmit the electricity generated from sources developed under those sections that is ultimately used to provide service to the utility's retail customers, including studies necessary to identify new transmission facilities needed to transmit electricity to Minnesota retail customers from generating facilities constructed to satisfy the renewable energy objectives and standards, provided that the costs of the studies have not been recovered previously under existing tariffs and the utility has filed an application for a certificate of need or for certification as a priority project under section 216B.2425 for the new transmission facilities identified in the studies;
> (2) provide storage facilities for renewable energy generation facilities that contribute to the reliability, efficiency, or cost-effectiveness of the renewable facilities; or
> (3) develop renewable energy sources from the account required in section 116C.779.

Regarding cost recovery, the RCR Statute, Minn. Stat. §216B.1645, subd. 2 states that:

> The expenses incurred by the utility over the duration of the approved contract or useful life of the investment and expenditures made pursuant to section 116C.779 shall be recoverable from the ratepayers of the utility, to the extent they are not offset by utility revenues attributable to the contracts, investments, or expenditures. Upon petition by a public utility, the commission shall approve or approve as modified a rate schedule providing for the automatic adjustment of charges to recover the expenses or costs approved by the commission under subdivision 1, which, in the case of transmission expenditures, are limited to the portion of actual transmission costs that are directly allocable to the need to transmit power from the renewable sources of energy. The commission may not approve recovery of the costs for that portion of the power generated from sources governed by this section that the utility sells into the wholesale market.

B. REASONABLENESS OF NEW PROJECTS

On pages 6 through 10 of its petition, Xcel identified the following four new projects for recovery under the TCR Rider:

- CapX – Brookings 345 kV Transmission Line;
- Pleasant Valley-Byron 161 kV Transmission Line;
- Glencoe-Waconia 115kV Transmission Upgrade; and
- Buffalo Ridge Restoration Project (storm repair costs).

According to Xcel, the Brookings, Pleasant Valley-Byron, and Glencoe-Waconia transmission projects qualify for recovery under the TCR Statute; the Buffalo Ridge Restoration Project qualifies for recovery under the RCR Statute. The Department discusses each project below.

1. CapX – Brookings 345kV Transmission Line

On May 22, 2009, the Commission issued an Order granting Certificates of Need for the CapX2020 Fargo, Brookings and LaCrosse 345 kV transmission lines.[2] The Commission allowed Xcel to recover costs for the Fargo and LaCrosse lines in its 2010 and 2011 TCR Riders, but did not allow Xcel any recovery for the Brookings line due to uncertainty regarding the cost allocation among transmission system users under the MISO Tariff.[3]

Xcel again requests recovery of costs associated with the Brookings line. According to Xcel, there have been two key developments since the Commission's Order in Xcel's 2011 TCR filing. First, the Federal Energy Regulatory Commission (FERC) issued its order on rehearing upholding its prior decision approving the MISO's Multi Value Project (MVP) tariff. Second, on December 8, 2011 the MISO Board approved its initial portfolio of MVP projects for regional cost allocation, including the Brooking project. According to Xcel, the MISO Board's action moved the conditional approval granted to Brooking project in June 2011 to final approval. Xcel stated that in January 2012, the CapX2020 utilities (including Xcel) were scheduled to sign the Brooking Project construction agreements. Xcel stated that significant construction is scheduled to occur in 2012, with the Company's share of investments expected to reach approximately $126 million by year end. As a result, Xcel seeks TCR recovery of approximately $6.5 million in project revenue requirements for 2012.

Based on the above, the Department concludes that the uncertainties regarding cost allocations for the Brooking project have been reasonably resolved. As a result, the Department concludes that this project qualifies for recovery under the TCR Statute.

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[2] In the Matter of the Application of Great River Energy, Northern States Power Company (d/b/a Xcel Energy and Others for Certificates of Need for the CapX 345-kV Transmission Projects, Order Granting Certificates of Need with Conditions, May 22, 2009, Docket No. ET2,E002 et. al/CN-06-1115.

[3] Commission's April 27, 2010 Order in Docket No. E002/M-09-1048; Commission's October 11, 2011 Order in Docket No. E002/M-10-1064.

2. Pleasant Valley-Byron 161 kV Transmission Line

On February 28, 2011, the Commission issued an Order granting a Certificate of Need for the Pleasant Valley-Byron transmission line in Docket No. E002/CN-08-992.

According to Xcel, the Pleasant Valley-Byron transmission line is needed to enable two wind farms to deliver energy without operating restrictions and to help close the gap in wind outlet transmission capability in 2012 that was identified in the 2007 Minnesota Transmission Owners Biennial Report. In addition, Xcel stated that the project will provide additional import capacity in the Rochester area. The Company seeks TCR recovery of approximately $356,000 in project revenue requirements for 2012.

Xcel stated on page 8 of its filing that a portion of the revenue requirements associated with this project was already being recovered in base rates in its 2010 rate case (Docket No. E002/GR-10-971). As a result, Xcel proposes to deduct $123,000 in revenue requirements from rider recovery.

Based on the above, the Department concludes that this project qualifies for recovery under the TCR Statute. Moreover, the Department agrees that it is appropriate to deduct $123,000 in revenue requirements for the portion of the project already being recovered in base rates.

3. Glencoe – Waconia 115kV Transmission Upgrade

On November 14, 2011, the Commission issued an Order granting a Certificate of Need for the Glencoe-Waconia Transmission Line in Docket No. E002/CN-09-1390.

According to Xcel, the project entails constructing approximately 2 miles of new 69 kV transmission line, 6 miles of new 115 kV transmission line, and upgrading approximately 20 miles of 69 kV transmission line to 115 kV capacity near the cities of Glencoe, Norwood Young America, and Waconia along with certain substation modifications located in the southwest metro area of the Twin Cities. In addition, Xcel stated that the project is located within Carver and McLeod Counties and that the Southwest Twin Cities Load Serving Study Review identified the need for transmission upgrades in the Glencoe – Waconia area to prevent significant low voltage and line overload conditions. The Company seeks TCR recovery of approximately $688,000 in project revenue requirements for 2012.

Xcel stated on page 8 of its filing that a portion of the revenue requirements associated with this project is already being recovered in base rates in its 2010 rate case (Docket No. E002/GR-10-971). As a result, the Company proposes to deduct $56,000 of revenue requirements from rider recovery.

Based on the above, the Department concludes that this project qualifies for recovery under the TCR Statute. Moreover, the Department agrees that it is appropriate to deduct $56,000 in revenue requirements for the portion of the project already being recovered in base rates.

4. Buffalo Ridge Restoration Project (storm repair costs)

Beginning on page 9 of its petition, Xcel stated that the Buffalo Ridge Restoration Project (BR Project) entails 64 miles of 115kV transmission lines and 30 miles of 34.5 kV wind feeder collector facilities. According to Xcel, these facilities incurred significant damage during a severe storm that occurred in Pipestone, Lincoln, and Lyon Counties in southwest Minnesota on July 1, 2011. As a result, Xcel stated that it incurred approximately $38 million in unanticipated 2011 transmission investment to restore these transmission facilities. Xcel stated that, because restoration of the 115 kV lines and the 34.5 kV collector feeders was needed for renewable wind energy to be delivered from the generators on Buffalo Ridge to the Company's load centers, the Company believes its investments are eligible for TCR recovery under the Renewable Statute. In addition, since all of the restoration facilities are now in service, Xcel concluded that these transmission restoration costs meet the requirements established by the Commission in its early Renewable Cost Recovery rider orders.

Xcel also stated on page 9 of its petition that:

> These transmission restoration costs were not included in the test year in the Company's 2011 electric rates case, therefore the Company is seeking to recover approximately $3.9 million of revenue requirements in the 2012 TCR. However, the cost of the facilities that were damaged and removed was included in transmission rate base in the 2011 test year. Because of this, Attachment 29 provides the calculation of the credit (approximately $350,000 for the Minnesota jurisdiction) to the TCR revenue requirements to be made in order to account for the revenue requirements included in our base rates for the facilities that were removed. This credit is only needed until the cost of the previous facilities can be retired from the Company's books and taken out of base rates.

The Department asked Xcel several questions regarding its Buffalo Ridge Restoration Project in DOC Information Request No. 1. Copies of the Company's responses are provided in DOC Attachment 1.

The Department asked Xcel, in DOC Information Request No. 1(g), to provide the amount of transmission repair expense included in the Company's most recent rate case (Docket No. E002/GR-10-971). Xcel replied that:

> Under Company accounting guidelines, all storm repairs of the type addressed by the Buffalo Ridge Restoration Project are capitalized and are not considered a transmission O&M expense. Therefore, none of the costs related to this project were expensed.
>
> The Company's 2011 test year rate case (Docket No. E002/GR-10-971) included a storm and emergency capital project for $1.5 million for routine storm related transmission restorations. During 2011, the Company spent approximately $1.9 million on storm related work that was recorded to this project but was unrelated to the Buffalo Ridge Restoration Project. In other words, all of the Buffalo Ridge storm project costs were extraordinary, above and beyond the amount included in our 2011 test year rate case and occurred during 2011. The Company is not seeking recovery of the additional $0.4 million of "routine" transmission storm restoration costs incurred in 2011 but not included in the test year.

The Department agrees that storm repair costs can either be capitalized and/or expensed (based on review of capital verse expense criteria) in a test year. In this case, the Department concludes that the costs in question are capital costs and were not included in the 2011 test year (with the exception of internal capitalized costs). The issue of internal capitalized costs is discussed separately below.

The Department asked Xcel, in DOC Information Request No. 1(f), if any repairs to existing transmission facilities qualify for recovery under the TCR Rider and, if so, whether the costs of repairs to any part of the transmission system, including facilities that have never been included in the TCR, qualify for cost recovery under the TCR Rider. Xcel responded that:

> The Renewable Statute does not specifically limit the type of costs (e.g., initial capital expenditure costs or "repair" costs). The statute simply refers to "actual costs." The Company is only seeking recovery of the Minnesota jurisdictional portion of its actual restoration costs.
>
> The Company does not believe that costs on "any part of the transmission system" would be eligible for recovery. The costs would need to be related to delivery of renewable energy, as required by the Renewable Statute. In this instance, the facilities reconstructed were either 34.5 kV collection feeders directly connecting the wind generation to the high voltage transmission system, or 115 kV facilities in the Buffalo Ridge area.

> Major capital transmission replacement projects qualify for Renewable Statute project treatment and, as explained above, recovery under the TCR Rider when those major capital transmission projects are needed to transmit power from renewable sources of energy to allow the Company to meet its renewable energy mandates. The Commission recognized that view in its Order approving the Certificate of Need for the 825 Wind Upgrade project. Several of the projects approved in that CON order were upgrades to or replacements of existing transmission facilities. The Commission affirmed that the Company's request was based on the fact that "the lines are needed to meet a transmission deficit that is preventing the development of wind energy in Minnesota, thereby frustrating state policies requiring Minnesota utilities in general, and Xcel [Energy] in particular, to rely more heavily on wind generation." Just as the 825 Wind Upgrade project facilities were needed to resolve a transmission deliverability deficit preventing the Company from increasing its use of wind generation, the storm of July 1, 2011 damaged the transmission facilities on the Buffalo Ridge such that there was again a deficiency in transmission delivery capability for wind generation. The Buffalo Ridge Restoration project solved that deficiency.
>
> Without the prompt major capital transmission repair undertaken in the Buffalo Ridge Restoration project, the wind generation on the Buffalo Ridge that is already developed (as provided for via the BRIGO and 825 Wind Upgrade projects) could not continue to be used to meet the state's renewable energy mandates. Thus the Buffalo Ridge Restoration project costs were necessary to comply with the state's renewable energy mandates. In addition, the Company could have been subject to significant curtailment payments under its PPAs, affecting rates through the fuel clause adjustment.
>
> While each situation would need to be evaluated on its own merits, the Company believes that if another major capital transmission repair were needed to allow renewable generation to continue to be used to meet the state's renewable energy mandate, that repair project would be considered a Renewable Statute project and thus be eligible for recovery under the TCR Rider.

The Department reviewed Xcel's response to DOC Information Request No. 1 and notes that the Company stated: "No direct facilities from the BRIGO project were damaged by the storm of July 1, 2011, so the Buffalo Ridge Restoration Project does not include repair of any of those

BRIGO facilities directly." Thus, the facilities that were repaired are not those that were approved in the certificate of need for the BRIGO lines, Docket No. E002/CN-06-154.

The Department agrees that the RCR Statute refers to costs of transmitting power and may appear not to limit the types of costs available for recovery. However, the purpose of this statute is to encourage utilities to make specific investments in *new* infrastructure that has been previously approved by the Commission to meet the wind, biomass or renewable mandates. Consistent with the goal of building new infrastructure, Minn. Stat. §216B.1645, subd. 2a provides the following requirement for pre-certification by the Commission:

> Subd. 2a. **Cost recovery for utility's renewable facilities.**
> (a) A utility may petition the commission to approve a rate schedule that provides for the automatic adjustment of charges to recover prudently incurred investments, expenses, or costs associated with facilities constructed, owned, or operated by a utility to satisfy the requirements of section 216B.1691, *provided those facilities were previously approved by the commission under section 216B.2422 or 216B.243, or were determined by the commission to be reasonable and prudent under section 216B.243, subdivision 9. For facilities not subject to review by the commission under section 216B.2422 or 216B.243, a utility shall petition the commission for eligibility for cost recovery under this section prior to requesting cost recovery for the facility.* (Emphasis added)

The requirement of pre-certification is echoed in the Commission's implementation of the statute, such as ordering paragraph 4 of the Commission's April 27, 2010 Order in E002/M-09-1048, which stated:

> In setting guidelines for evaluating project costs going forward, the TCR project cost recovered through the rider should be *limited to the amounts of the initial estimates at the time the projects are approved as eligible projects*, with the opportunity for the Company to seek recovery of excluded costs on a prospective basis in a subsequent rate case. A request to allow cost recovery for project costs above the amount of the initial estimate may be brought forward for Commission review only if unforeseen and extraordinary circumstances arise on the project. (Emphasis added).

The reference to pre-certification is consistent with the goal of the statute to encourage utilities to build new infrastructure needed to meet the wind mandate, biomass mandate, or renewable energy objective, that has been approved by the Commission as being eligible for recovery prior to when the utility requests recovery of the costs. Xcel did not request eligibility of the costs prior to filing the current request for cost recovery.

The Department notes that the Company appears to agree that the BR Project would not be eligible for recovery under Minn. Stat. §216B.16 Subd. 7(b) (TCR), but argues that the project qualifies under the renewable statute, Minn. Stat. §216B.1645, subd 2a. As discussed above, Xcel argues that because the transmission assets included in the BR Project are necessary to deliver renewable energy, the BR Project qualifies as a facility "constructed, owned, or operated by a utility to satisfy the requirements of section 216B.1691."[4]

Xcel takes a very broad interpretation of the type of project eligible for cost recovery under the statute. Indeed, nearly all transmission facilities can be said to deliver energy, and thus at least some that energy is likely to be renewable. Clearly, not all transmission investments could qualify for recovery under the renewable rider; thus it is appropriate to consider what type of transmission investments would qualify for recovery under the renewable rider.

First the Department notes that new transmission facilities (as opposed to rebuilding existing facilities, such as Xcel requests), regardless of how much renewable energy they actually deliver, are eligible for rider cost recovery under §216B.16 subd. 7(b). Further, reasonable investments in utility infrastructure are allowed in base rates when a utility files a rate case. Thus, the question is whether Minn. Stat. §216B.1645 allows cost recovery *in a rider* when the Company makes transmission investments in facilities that are not new, but that deliver renewable energy by virtue of being interconnected to a utility system that includes renewable energy.

Minn. Stat. §216B.1645, subd 2a, allows for recovery of "prudently incurred investments, expenses, or costs associated with facilities constructed, owned, or operated by a utility to satisfy the requirements of section 216B.1691."

Minn. Stat. §216B.1691, subd. 2a (b) states, in part, that:

> An electric utility subject to this paragraph *must generate or procure sufficient electricity generated by an eligible energy technology* to provide its retail customers in Minnesota or the retail customer of a distribution utility to which the electric utility provides wholesale electric service so that at least the following percentages of the electric utility's total retail electric sales to retail customers in Minnesota are generated by eligible energy technologies by the end of the year indicated:

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[4] Minn. Stat. §216B.1645, subd 2a

(1)	2010	15 percent
(2)	2012	18 percent
(3)	2016	25 percent
(4)	2020	30 percent.

[Emphasis Added]

Further, "eligible energy technology" is defined by the state as:

> …an energy technology that generates electricity from the following renewable energy sources:
> (1) solar;
> (2) wind;
> (3) hydroelectric with a capacity of less than 100 megawatts;
> (4) hydrogen, provided that after January 1, 2010, the hydrogen must be generated from the resources listed in this paragraph; or
> (5) biomass, which includes, without limitation, landfill gas; an anaerobic digester system; the predominantly organic components of wastewater effluent, sludge, or related by-products from publicly owned treatment works, but not including incineration of wastewater sludge to produce electricity; and an energy recovery facility used to capture the heat value of mixed municipal solid waste or refuse-derived fuel from mixed municipal solid waste as a primary fuel.

The definition of "eligible energy technology" is limited by Minn. Stat. §216B.1691 to generation facilities. Thus, the Department concludes that a reasonable interpretation of the type of facilities contemplated by Minn. Stat. §216B.1645, subd. 2a, is also limited to generation facilities. The RES requires that a specified percentage of energy sold at retail be derived from renewable sources. As generation, not transmission, produces renewable energy, the Department concludes that is reasonable to exclude transmission costs from recovery under Minn. Stat. §216B.1645, subd 2a. The Department again notes that any new transmission facilities can be recovered through a rider under §216B.16 subd. 7(b).

Under the Department's interpretation of Minn. Stats. §§216B.1691 and 216B.1645, utilities can request cost recovery of any renewable generation investment to meet the RES that has been determined by the Commission to be eligible for rider cost recovery as well as any such investment in new transmission facilities. It is only repair or maintenance costs associated with existing transmission that the Department concludes should not be eligible for rider recovery.

That interpretation is reflected in the statutory requirement for determination under the certificate of need statute or similar proceeding.

The Department notes that one of the policy reasons for the creation of the renewable and transmission riders was to provide an incentive for utilities to make those new investments. Minn. Stat. §216B.04 requires utilities to provide "safe, adequate, efficient and reasonable service." Clearly, making repairs and performing maintenance to existing transmission infrastructure is necessary to meet that statutory obligation and does not warrant special ratemaking treatment in a rider.

While the Department does not recommend recovery of the repair costs in the rider, the Department concludes that Xcel is entitled to request recovery of the repair costs in its upcoming rate case. For that proceeding, the Department recommends that the Commission require Xcel to indicate in its initial filing whether the Company received any insurance proceeds or other compensation, reduction in taxes or other considerations for storm damage to these facilities.

C. REASONABLENESS OF PROJECT REVENUE REQUIREMENTS AND COST RECOVERY CAPS

1. Brookings Project

In the Commission's 2010 TCR Order, the Commission set the standard for evaluation of TCR Project Costs going forward as follows:

> …the Commission finds that TCR project cost recovery through the rider should be limited to the amount of the initial cost estimates at the time the projects are approved as eligible projects, with the opportunity for the Company to seek recovery of excluded costs on a prospective basis in a subsequent rate case. A request to allow cost recovery for project costs above the amount of the initial estimate may be brought for Commission review only if unforeseen or extraordinary circumstances arise on a project.

Xcel addresses the issue of cost recovery caps on page 3 of its filing. Xcel also provided an analysis, in Attachment 42 of its filing, comparing 2012 TCR project costs with initial cost estimates. According to Xcel, none of the project costs included the 2012 TCR Rider are above their initial cost estimates.

The Commission's May 22, 2009 Order in Docket No. E002/CN-06-1115 approved a project cost range of \$654-\$725 million for the Brookings project. As noted in Attachment 1, Page 3 of 8 and in Attachment 42, the Company proposes to add an additional \$30 million of system upgrade costs to the high-end of the Commission approved project cost range of \$654-725 million for purposes of determining the project's cost recovery cap. The Department notes that the Commission also approved the Applicants' estimate of $70-100 million in transmission upgrades system-wide due to the new 345 kV lines. The Department recommends that Xcel explain in reply comments whether the $30 million it identifies in the instant petition is in addition to the $70-100 million in upgrades identifies in the CAPX CN proceeding and, if so, why it is reasonable for ratepayers to pay for these costs.

2. *Bemidji Project*

Xcel states that the cost cap for the Bemidji project is $60.6 – 99.1 million. That cost range is based on the transmission alternatives shown in Table 6.3-6 of the Certificate of Need Application in Docket E-017, E-015, ET-6/CN-07-1222 as reproduced below:

Table 6.3-6 Cumulative Present Value of Revenue Requirements for Each Corridor (Including Value of 40-Year Loss Savings)

Corridor	Installed Cost ($ millions)	Cumulative PVRR ($ million)		
		Capital Related PVRR	Loss Savings	Net PVRR
Preferred Corridor (68 miles)	$60.6	$122.0	-$32.0	$90.0
Southern Corridor (99 miles)	$84.6	$170.0	-$28.0	$143.0
Northern Corridor (116 miles)	$99.1	$200.0	-$26.0	$175.0

The $99.1 million high end of the range was the cost estimate if the route chosen was the northern route around the Leech Lake Reservation that would have been 48 miles longer than the preferred route. As the Northern Corridor was not the chosen route, it is not appropriate to use the cost estimates for the North Corridor when the Preferred Corridor was the selected corridor for construction.

Xcel further states that costs for rights-of-way, ancillary permitting, and the required transmission system upgrade were not included in the cost estimate presented to the Commission in the Certificate of Need. These costs add $24.8 million to the total cost of the Bemidji Project.

Xcel states that the Environmental Report indicated that the cost estimates presented to the Commission did not include the cost of "right-of-way, permitting and ancillary costs." The Department notes that the Certificate of Need application also states that right-of-way, permitting and ancillary costs were not included. Further, regarding the transmission system upgrades, Xcel states that, since the Order in Docket No. E002/CN-06-1115 contemplated additional upgrades, the Commission should allow additional costs for transmission upgrades here as well.

It is important for CN applicants to include all costs in their estimates. Further, as indicated above, the Commission already decided in the Commission's Order in Docket No. E002/M-09-1048 that such costs are not allowed to be recovered in riders, but are eligible for recovery in a rate case.

Thus the Department concludes that the appropriate cap for the Bemidji Project is $60.6 million. It may be reasonable to escalate those costs to current dollars based on an index such as the producer price index (PPI) published by the Bureau of Labor Statistics. If Xcel believes that the cost of the Bemidji Project should be escalated to current day dollars, the Department recommends that Xcel include an escalation factor in reply comment and an explanation of its appropriateness for use in this proceeding.

D. RECB (SCHEDULE 26) CHARGES

During the 2008 Minnesota Legislative Session, Minn. Stat. 216B.16, subd, 7(b) (2) was amended to allow utilities providing transmission service to recover "the charges incurred by a utility that accrue from other transmission owners' regionally planned transmission projects that have been determined by MISO to benefit the utility, as provided for under a federally approved tariff," upon Commission approval. The Statute further requires any recovery to "be reduced or offset by revenues received by the utility and by amounts the utility charges to other regional transmission owners, to the extent those revenues and charges have not been otherwise offset."

Similar to its 2011 TCR filing, Xcel proposes to recover the net charges it pays to other electric utilities through MISO's Schedule 26 in the instant filing. Under Xcel's proposal, it would recover the estimated amount of payments it makes under MISO Schedule 26 net of the estimated amount of revenues it receives from other utilities under MISO Schedule 26. Xcel proposes to recover approximately $1.4 million of net MISO Schedule 26 charges in its 2012 TCR Rider. The Department notes that Xcel's proposed approach is consistent with past TCR filings.

On page 7 of its petition, Xcel addressees an alternative approach for recovery of MISO Schedule 26 charges. Xcel stated that:

> The MISO RECB revenue requirement calculations provided in this filing were prepared in the same way the Commission has approved treatment of these regional costs and revenues since MISO RECB revenue requirements became eligible for inclusion in the TCR. For reference, this is based on the "All-In" cost recovery method described in the on-going Otter Tail Power Company ("Otter Tail") Transmission Cost Recovery Rider filing (Docket E002/M-10-1061). The Company is aware that an alternative cost recovery method referred to as the "Split" method has been discussed in the Otter Tail TCR docket.

> The Company takes no position on use of the alternative "Split" cost recovery method in this TCR filing; however, the Company does understand the potential importance of this issue as the amount of new investment the Company makes in the transmission system continues to grow, particularly for transmission projects that will receive broad cost sharing treatment as MVP projects under the MISO tariff.
>
> It may be appropriate to further consider the issue of the appropriate cost recovery method to recognize revenue requirements associated with MISO cost shared transmission projects. The Company suggests that a broader cost recovery forum, such as a general rate case, would be a better place for that consideration. The Company would welcome Commission direction to address this issue in an appropriate forum.

The Department notes that on May 26, 2012 the Commission issued its Order in Docket No. E017/M-10-1061. As stated therein, the Commission rejected Otter Tail's alternative cost recovery method in favor of the standard or all-in approach. As such, the Department considers this issue to be resolved and recommends that the Commission deny Xcel's suggestion that this issue be addressed in a broader cost recovery forum.

E. RATE OF RETURN ON INVESTMENT

The TCR Statute allows for a return on investment at the level approved in the utility's last general rate case, unless a different return is found to be consistent with the public interest. Xcel used an overall rate of return of 8.83 percent as allowed by the Commission in its last rate case, E002/GR-08-1065.

The Department notes that on May 14, 2012 the Commission issued its Order in Xcel's 2010 rate case (Docket No. E002/GR-10-971). As stated therein, the Commission approved an overall rate of return of 8.32 percent. The Department recommends that the Company provide, in reply comments, its revised revenue requirement calculations and its updated 2012 TCR Rate Adjustment Factors using the Commission's recently approved rate of return of 8.32 percent.

F. ALLOCATION OF COSTS

1. Allocation between wholesale and retail

In its March 29, 2007 *Order Making Determination of TCR Project Eligibility, 2007 TCR Adjustment Rates, Notice of Annual RCR Compliance Reports* in Docket No. E002/M-06-1505, the Commission ordered Xcel to include a revenue credit in its calculation of revenue requirements for wholesale revenues received under the Company's Open Access Transmission

Tariff (OATT). Consistent with its methodology in previous TCR filings, Xcel proposes to estimate the OATT revenue credit to the forecasted revenue requirement for each project under the TCR Rider. The Department concludes that Xcel's methodology is reasonable.

2. Allocation between jurisdictions

For the determination of its Minnesota jurisdictional revenue requirement, Xcel uses a demand allocator, which reflects the sharing of costs between the Company (NSP-Minnesota) and NSP-Wisconsin pursuant to the Interchange Agreement. Minnesota system costs are further allocated among Minnesota, North Dakota, and South Dakota customers based on demand allocation factors approved by the Commission in prior TCR filings. The cost allocation methodology is consistent with the methodology used in previous rate adjustment filings. As a result, the Department concludes that Xcel's methodology is reasonable. However, the Department recommends that any revisions to the Interchange Agreement or the demand allocators approved by the Commission in the Company's 2010 rate case be reflected in the 2012 TCR Rate Adjustment Factors. The Department recommends that Xcel provide this information in their reply comments.

3. Allocation Between Customer Classes and Applicable Recovery Rates

Xcel's Minnesota jurisdictional classes include Residential, Commercial Non-Demand, Street Lighting, and Demand Billed and are allocated costs based on demand allocators approved by the Commission in Xcel's 2008 electric rate case (Docket No. E002/GR-08-1065). The non-demand metered classes of service (Residential, Commercial Non-Demand, and Street Lighting) are billed on an energy-only basis (per kWh). Xcel's Demand Billed customers are billed on a demand-only basis (per kW). The allocation method is consistent with methods used in previous TCR rate adjustment filings. Xcel stated that it used the transmission demand and sales allocation percentages established in its last electric rate case, E002/GR-08-1065.

Xcel stated in footnote 8 on page 11 of its petition that, if the Commission issued its final Order in the Company's 2010 rate case before it makes a final determination in this proceeding, the Company would recalculate its proposed 2012 TCR rate factors by customer class using the allocation factors used in the 2011 test year revenue requirement. Xcel stated that it would reflect the updated allocation factors in its compliance filing in this docket.

Since the Commission issued its Order in Xcel's 2010 rate case on May 14, 2012, the Department recommends that Xcel recalculate its proposed TCR rate factors by customer class using the test-year allocation factors from its 2010 rate case. The Department recommends that Xcel provide this information in its reply comments.

In the Commission's October 21, 2011 TCR Order, the Commission stated that:

> In its next annual filing, Xcel [Energy] shall include a rate design alternative proposal reflecting the allocation of the TCR rate adjustment based on the percentage of revenue basis, illustrating comparative impacts on the customer classes and customers within the demand-billed class.

Xcel stated on page 16 of its petition that it performed the requested analysis in Attachment 41 of its petition. The Company further states that the percentage-of-revenue approach to allocations of the TCR rate adjustment revenue requirements results in a lower TCR billing for demand-metered customers of about 18 percent on average, a higher TCR billing for non-demand-metered customers of about 1 percent for residential customers and a 30 percent higher TCR billing for commercial non-demand metered customers.

The DOC notes that there are valid policy reasons for using a demand-based charge for transmission expenses. For example, the DOC notes that transmission is generally needed to meet peak demand needs, not energy needs. However when transmission is built to interconnect a wind generator, the need for which is based on the level of a utility's sales, or when transmission is built to meet multiple needs, as in the case of the Brookings line, it is difficult to determine what portion of the line was need to meet demand, energy, or policy needs. Since the majority of the transmission costs are not wind related, the Department does not recommend a change in the use of the demand allocator at this time. The Department will consider other parties comments and address this issue further in our reply comments.

G. COMPLIANCE AND TRUE-UP OF 2011 TCR COSTS

Xcel provided its 2011 TCR Compliance Filing, True-up Report, and Tracker Balance in Attachments 30-33 of its filing. As such, Xcel proposes to decrease its 2012 TCR revenue requirements by $432,253 to reflect prior over-recoveries. Xcel's proposed 2011 carryover balance is summarized as follows:

2011 Transmission Statute Revenue Requirement	$12,432,553
2011 Renewable Statute Revenue Requirement	$156,999
Adjustment for Rev. Requirement in Base Rates	($122,004)
Rev. Requirement Impact Project 18 Retirement	($67,146)
Carryover from 2010	($2,029,342)
Total 2011 Revenue Requirements	$10,281,060
2011 Revenues from TCR Rider	$10,713,313
2011 Carryover balance	($432,253)

The Department notes that the 2011 Renewable Statute revenue requirements of $156,999 and the Project 18 retirement revenue requirements of ($67,146) are related to the Buffalo Ridge Restoration Project. Since the Buffalo Ridge Restoration Project is one of four new projects proposed for recovery in the instant filing, the Department recommends that Xcel explain, in reply comments, why these revenue requirement amounts are included in the Company's 2011 TCR Compliance Filing, True-up Report, and Tracker Balance.

H. INTERNAL CAPITALIZED COSTS

Minnesota regulation has a history of denying recovery of internal costs outside of a rate case.[5] More recently, in Minnesota Power's 2010 TCR filing (Docket No. E015/M-10-799), the

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- Docket No. E002/M-03-1462. In the Matter of Northern States Power Company d/b/a Xcel Energy for Approval of Deferred Accounting for Costs Incurred for the Web Tool and Time-of-Use Pilot Project; specifically DOC (then OES) comments dated July 27, 2004 and as approved in the February 25, 2005 Commission Order.
- Docket No. E002/M-06-1315. In the Matter of Northern States Power Company d/b/a Xcel Energy Petition for Approval of Deferred Accounting Treatment of Costs Related to the Mercury Emissions Reduction Act of 2006; specifically OES comments dated November 15, 2006 and as approved in the January 31, 2007 Commission Order in Docket No. E001/M-09-336. In the Matter of Interstate Power and Light Company's Petition for Approval of Deferred Accounting Treatment of the Costs Related to Cancelled Sutherland Generating Station Unit 4; the DOC recommended that the Commission deny IPL's request for deferred accounting for a coal plant that the Company ultimately decided to abandon; however, in the event that the Commission approved IPL's request, the DOC recommended that the Commission deny recovery for IPL's internal related costs (DOC comments dated July 1, 2009). The Commission ultimately denied IPL's request for deferred accounting in its December 18, 2009 Order.
- Docket No. E015/PA-09-526. In the Matter of Minnesota Power's Petition to Purchase Square Butte Cooperative's Transmission Assets and Restructure Power Purchase Agreements from Milton R. Young Unit 2 Generating Station. The DOC recommended and MP agreed to remove any internal costs associated with its purchase of the transmission assets and the renegotiation of its purchase power agreements.
- Docket No. E002/M-09-1083. In the Matter of the Petition of Northern States Power Company, a Minnesota Corporation for approval of the 2010 Renewable Energy Standard Cost Recovery Rider and 2009 RES Tracker Report; specifically in DOC reply comments dated February 26, 2010 and as approved in the April 22, 2010 Commission Order.
- Docket No. E017/M-09-1430. In the Matter of Otter Tail Power Company's Petition Requesting Authority to Use Deferred Accounting for Costs Incurred During its Participation in the Big Stone II Project; specifically DOC comments dated March 17, 2010. Otter Tail Power Company later withdrew its deferred accounting request and is addressing the issue in its pending rate case in Docket No. E017/GR-10-239, in accordance with the Commission's Order dated June 7, 2010.
- Docket No. E017/M-09-1484. In the Matter of Otter Tail Power Company's Request for Approval of its 2010 Renewable Resource Cost Recovery Adjustment Factor; specifically DOC comments dated March 17, 2010 and July 9, 2010. In its Order dated August 27, 2010, the Commission denied Otter Tail Power Company's request to include capitalized labor and internal costs, subject to future true-up if the Commission determines in Otter Tail's pending rate case, Docket No. E-017/GR-10-239, that the amount should be included.
- Docket No. E002/M-09-1488. In the Matter of Xcel Energy's Petition for Approval of Two Proposed Energy Innovation Corridor Projects in the Central Corridor Utility Zone and Deferred Accounting

Commission required Minnesota Power to exclude internal capitalized costs from its TCR Rider. Minnesota Power also excluded its internal capitalized cost from its 2011 TCR Rider (Docket No. E015/M-11-695) which is currently awaiting scheduling on a Commission agenda. As a result, the Department asked Xcel, in DOC Information Request No. 3, if the Company included internal capitalized costs in its TCR Rider and, if so, to provide the amount of internal capitalized costs included in the TCR Rider and their impact on the revenue requirement calculations. Xcel responded that:

> Xcel Energy did include internal capitalized costs in the 2012 TCR Rider, consistent with prior TCR Rider filings and the FERC Uniform System of Accounts and Minn. Stat. 216B.10. FERC rules require labor and overheads associated with the installation of capital projects be categorized as capital expenses not operating expenses. See 18 CFR Ch 1, pt. 101(3)(A)(2).
>
> Please see Attachment A, Page 1, for the internal labor costs with associated labor loadings by project group for 2012. Percentages for CWIP and RWIP were calculated by taking the total internal labor costs (plus associated labor loadings) divided by the total capital charges. These percentages were then applied to all CWIP or RWIP related inputs to reduce the charges in the rider. The revenue requirement impact of the internal capitalized costs starting in 2012 is approximately $1.5 million as shown on Attachment A, page 2.

As shown in the Company's response to DOC Information Request No. 2, Attachment A, a significant portion the costs included for recovery are capitalized internal costs. As a result, the Department recommends that the Commission deny Xcel's proposal to recover this $1.5 million revenue requirement amount of internal capitalized costs in its TCR Rider.

IV. SUMMARY AND RECOMMENDATIONS

The Department recommends that Xcel explain in reply comments:

- whether the $30 million it identifies in the instant petition is in addition to the $70-100 million in upgrades identifies in the CAPX CN proceeding and if so why ratepayers should pay this amount;
- the basis for an appropriate escalator for the cost of the Bemidji Project; and

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Treatment for Costs Incurred After January 1, 2010; specifically DOC comments dated April 12, 2010 and September 9, 2010; item waiting Commission Agenda.

- why there are Buffalo Ridge Restoration costs included in the Company's 2011 TCR Compliance Filing, True-up Report, and Tracker Balance.

In addition, the Department recommends that Xcel provide in reply comments its revised 2012 TCR revenue requirements and updated TCR rate adjustment factors using the allocators factors and the overall rate of return approved by the Commission in the Company's 2010 rate case.

Further, the Department recommends that the Commission:

- Approve Xcel's petition with the following modifications:
  - Exclude from the rider the costs of repairs to the existing transmission system on the Buffalo Ridge. Such costs can be requested in a subsequent rate case.
  - Disallow from recovery in the rider costs that the Company did not include in previous requests for eligibility (e.g. certificates of need), including the cost estimates for right-of-way, permitting ancillary costs and additional costs for transmission upgrades. Such costs can be requested in a subsequent rate case.
  - Deny Xcel's proposal to recover internal capitalized costs amounting to $1.5 million in revenue requirements in its 2012 TCR Rider.
- Require Xcel to explain in its initial filing in its next rate case whether the Company received any insurance proceeds for storm damage to related to its Buffalo Ridge Restoration project.

The Department does not recommend a change in rate design at this time but will review the comments of other parties.

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☒ **Public Document**

Xcel Energy		
Docket No.:	E002/M-12-0050	
Response To:	Christopher Shaw, Mark Johnson	Information Request No. 1
Requestor:	Dept of Commerce	
Date Received:	March 14, 2012	

Question:
Please provide further information regarding the Buffalo Ridge Restoration Project. Specifically:

a. What portion of the Restoration Project is replacement of infrastructure that was installed as part of the BRIGO Project?
b. Were any warranties in effect on the recently installed infrastructure being replaced?
c. Are there alternatives available that would withstand a similar storm?
d. Are the 34.5 kV lines that were damaged transmission or distribution lines?
e. Why would eligibility for recovery under the renewable cost recovery rider allow for recovery under the TCR Rider?
f. Do repairs to existing facilities qualify for recovery under the TCR Rider? If so, would the costs of any repairs to any part of the transmission systems, including facilities that have never been included in a TCR, qualify for cost recovery under the TCR Rider?
g. Please provide the amount of transmission repair expense included in Xcel's current rate case (Docket No. E002/GR-10-971).

Response:

a. No direct facilities from the BRIGO project were damaged by the storm of July 1, 2011, so the Buffalo Ridge Restoration Project does not include repair of any of those BRIGO facilities directly. However, as stated in the petition, the storm damaged the main 115 kV transmission line – Pipestone to Lyon County – which is needed for the wind generation on the Buffalo Ridge, including the wind generation added as a result of the BRIGO and 825 Wind Upgrade facilities, to be deliverable to Company load centers.

b. No warranties existed for any of the equipment (poles, towers, conductors, etc.) destroyed by the storm of July 1, 2011. Equipment manufacturers do not warrant that their equipment can withstand a tornado or severe storm.

c. No economically practical alternatives would have existed for the rural rebuild of the 64 miles of 115 kV overhead transmission line from Pipestone to Lyon County. Further, no economically practical alternatives exist for the rebuild of 40 miles of overhead 34.5 kV wind collection feeders.

Reconstructing the facilities underground would not be economic: the cost would have been approximately 10 times the cost of overhead construction for the 115 kV transmission facilities and similar orders of magnitude higher than the cost of overhead construction for the 34.5 kV facilities. In addition, underground construction would have taken considerably longer and would have required new environmental permits, given the terrain crossed by the facilities. The delays would have resulted in the potential for significant additional curtailment penalties under the Company's power purchase agreements (PPAs) with wind generators in the area. Overhead construction of the replacement 115 kV and 34.5 kV facilities is the Company's standard construction practice in the affected locations, and meets the requirements of the National Electric Safety Code.

d. All of the wind collection feeder lines are 34.5 kV lines that were originally designed to 34.5 kV distribution standards. However, since wind collection feeders serve the function of collecting generation and delivering that generation to the transmission system, the assets are recorded as transmission assets. The new wind collection feeders were built for 69 kV transmission wind and ice loading standards. While the reconstructed 34.5 kV lines will be more robust and improve overall reliability, lines constructed to 69 kV standards would still have experienced significant damage during the July 1, 2011 storm.

e. Since 2007, as discussed in the petition, the Company has recovered costs under both the Renewable Statute and the Transmission Statute through the TCR Rider. The Company's current request to recover the costs of a project that is eligible under the Renewable Statute, specifically the Buffalo Ridge Restoration project, under the TCR Rider is consistent with the underlying statute and Commission Orders on that very question.

The Renewable Energy Statute allows for recovery, through an automatic adjustment mechanism, of all investments entered into by a public utility in connection with satisfying renewable energy mandates. Minn. Stat. § 216B.1645, Subdivision 1, which states that:

> *...Upon petition by a public utility, the commission shall approve or approve as modified a rate schedule providing for the automatic adjustment of charges to recover the expenses or costs approved by the commission, which, in the case of transmission expenditures, are limited to the portion of actual transmission costs that are directly allocable to the need to transmit power from the renewable sources of energy. The commission may not approve recovery of the costs for that portion of the power generated from sources governed by this section that the utility sells into the wholesale market...*

The Buffalo Ridge Restoration Project was required in order to meet "the need to transmit power from the renewable sources of energy." In addition, the Company is only proposing to recover the Minnesota jurisdictional portion of the actual restoration project costs. The costs therefore meet the criteria spelled out above. Without the prompt restoration of the transmission facilities damaged in the July 1, 2011 storm, the renewable energy on the Buffalo Ridge could not be delivered to loads and, correspondingly, could not be used to meet the renewable energy mandates established by the State of Minnesota. The project not only resulted in restoration of wind collection feeders that directly affected approximately 300 MW of wind generation, it also put back in-service in a timely manner the 64 miles of 115 kV transmission line which allows for the reliable operation and delivery of approximately 1200 MW of wind generation in the Buffalo Ridge area. Therefore, the Buffalo Ridge Restoration project was just as needed for meeting the renewable energy mandates as was the BRIGO and 825 Wind Upgrade projects, both of which were allowed recovery under the TCR Rider.

In Docket No. E002/M-02-474, the Commission approved the Company's RCR adjustment tariff, which was a mechanism to facilitate recovery of transmission costs incurred to support the delivery of renewable energy projects in accordance with Minn. Stat. § 216B.1645 ("Renewable Statute"). The adjustment was determined based on the annual revenue requirements associated with eligible investments and expenses over a projected year, and provided for a true-up of actual costs and revenues. The Company implemented the initial RCR rate factors in December 2004, and the RCR factors were adjusted periodically and collected through the Company's Resource Adjustment factor on customer bills. The Company recovered transmission related costs required to deliver renewable energy via the RCR factors. Specifically, the Company previously recovered the cost of the following transmission projects pursuant to the RCR mechanism:

Renewable Energy Statute Projects
Recovered Under
The RCR Mechanism

Project #	**Project Description**	**Docket**
Project 1	Chanarambie Substation and 115 kV System Improvements Between Pipestone, Chanarambie, Lake Yankton, and Lyon County Substations	M-03-1882
Project 2	Black Dog Substation Transformer Replacement	M-03-1882
Project 3	345 kV Line Clearance Improvements from Wilmarth Substation to Lakefield Junction Substation	
Project 4	69 kV Line Upgrade from Bird Island Substation to Franklin Substation	M-03-1882 M-05-289
Project 5	115 kV Line Upgrade from Summit Substation to Loon Tap to West Faribault Substation	M-03-1882 M-05-289
Project 6	Troy Switching Substation	M-03-1882
Project 7	GM, LLC Project	M-03-1882
Project 8	Wind Generation Interconnects on the 345 kV System in Southwestern Minnesota	M-03-1882
Project 9	Alexandria to Douglas County 115 kV	M-05-289
Project 10	Wilmar to Kerkoven Tap 115 kV	M-05-289
Project 11	Minnesota Valley to Franklin 115 kV	M-05-289
Project 12	Paynesville to Wakefield 115 kV	M-05-289
Project 13	Upgrades to Marshall Municipal Utilities 115 kV	M-05-289
Project 14	Lakefield Junction to Fox Lake 161 kV Line	M-05-289
Project 15	Lakefield Junction Substation – to Interconnect Xcel Energy's Split Rock to Lakefield Junction 345 kV Line	M-06-411
Project 16	Western Area Power Administration's White Substation 345 kV Upgrades	M-06-411

The 2005 Legislature enacted Minn. Stat. 216B.16, Subd. 7b ("Transmission Statute"), which authorized the Commission to approve a tariff mechanism for an automatic annual adjustment of charges for new transmission facilities. The Transmission Statute also provided for recovery of the annual revenue requirements associated with eligible investments and expenses over a projected year, with a true-up of actual costs and revenues. On August 1, 2006, the Company petitioned the Commission in Docket No. E002/M-06-1103 to 1) establish a new TCR tariff, and 2) combine recovery of eligible projects as defined in both the Renewable Statute and the Transmission Statute under one annual automatic recovery mechanism, the TCR adjustment rider. The Commission approved that request in its November 20, 2006 Order in that same Docket.

On October 27, 2006, the Company petitioned the Commission in Docket No. E002/M-06-1505 to implement the Commission's Order permitting the inclusion of cost recovery of Renewable Statute projects and Transmission Statute projects in one automatic adjustment tariff, the TCR Rider. The Commission approved that request in its March 29, 2007 Order in that same docket and the Company made its Compliance filing on April 9, 2007 to begin charging customers On May 1, 2007. In every TCR Rider the Company has made since that time, the Company has requested and the Commission has approved the inclusion of cost recovery of Renewable Statute projects and Transmission Statute projects in the TCR Rider

Renewable Energy Statute Projects
Recovered Under
The TCR Mechanism

Project #	**Project Description**	**Docket**
Project 6	Rock County Collector Substation	M-06-1505 M-07-1156 M-08-1284
Project 10	Spare Wind Transformer	M-07-1156 M-08-1284
Project 15	Blue Lake – Wilmarth – Lakefield Transmission Line	M-09-1048 M-10-1064
Project 16	Nobles Wind Farm Network Upgrade	M-09-1048 M-10-1064
Project 18	Buffalo Ridge Restoration (Pending Approval)	M-12-50

Therefore, the Company's current request to recover the costs of a project that is eligible for recovery under the Renewable Statute, specifically the Buffalo Ridge Restoration project, through the TCR Rider is consistent with Commission Orders on that very question.

f. The Renewable Statute does not specifically limit the type of costs (e.g., initial capital expenditure costs or "repair" costs). The statute simply refers to "actual costs." The Company is only seeking recovery of the Minnesota jurisdictional portion of its actual restoration costs.

The Company does not believe that costs on "any part of the transmission system" would be eligible for recovery. The costs would need to be related to delivery of renewable energy, as required by the Renewable Statute. In this instance, the facilities reconstructed were either 34.5 kV collection feeders directly connecting the wind generation to the high voltage transmission system, or 115 kV facilities in the Buffalo Ridge area.

Major capital transmission replacement projects qualify for Renewable Statute project treatment and, as explained above, recovery under the TCR Rider when those major capital transmission projects are needed to transmit power from renewable sources of energy to allow the Company to meet its renewable energy mandates. The Commission recognized that view in its Order approving the Certificate of Need for the 825 Wind Upgrade project. Several of the projects approved in that CON order were upgrades to or replacements of existing transmission facilities. The Commission affirmed that the Company's request was based on the fact that "the lines are needed to meet a transmission deficit that is preventing the development of wind energy in Minnesota, thereby frustrating state policies requiring Minnesota utilities in general, and Xcel [Energy] in particular, to rely more heavily on wind generation." Just as the 825 Wind Upgrade project facilities were needed to resolve a transmission deliverability deficit preventing the Company from increasing its use of wind generation, the storm of July 1, 2011 damaged the transmission facilities on the Buffalo Ridge such that there was again a deficiency in transmission delivery capability for wind generation. The Buffalo Ridge Restoration project solved that deficiency.

Without the prompt major capital transmission repair undertaken in the Buffalo Ridge Restoration project, the wind generation on the Buffalo Ridge that is already developed (as provided for via the BRIGO and 825 Wind Upgrade projects) could not continue to be used to meet the state's renewable energy mandates. Thus the Buffalo Ridge Restoration project costs were necessary to comply with the state's renewable energy mandates. In addition, the Company could have been subject to significant curtailment payments under its PPAs, affecting rates through the fuel clause adjustment.

While each situation would need to be evaluated on its own merits, the Company believes that if another major capital transmission repair were needed to allow renewable generation to continue to be used to meet the state's renewable energy mandate, that repair project would be considered a Renewable Statute project and thus be eligible for recovery under the TCR Rider.

g. Under Company accounting guidelines, all storm repairs of the type addressed by the Buffalo Ridge Restoration Project are capitalized and are not considered a transmission O&M expense. Therefore, none of the costs related to this project were expensed.

The Company's 2011 test year rate case (Docket No. E002/GR-10-971) included a storm and emergency capital project for $1.5 million for routine storm related transmission restorations. During 2011, the Company spent approximately $1.9 million on storm related work that was recorded to this project but was unrelated to the Buffalo Ridge Restoration Project. In other words, all of the Buffalo Ridge storm project costs were extraordinary, above and beyond the amount included in our 2011 test year rate case and occurred during 2011. The Company is not seeking recovery of the additional $0.4 million of "routine" transmission storm restoration costs incurred in 2011 but not included in the test year.

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Date:	April 16, 2012

Preparer:	Paul J Lehman
Title:	Manager Regulatory Administration
Telephone:	612-330-7529
Date:	April 16, 2012

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☒ **Public Document**

Xcel Energy		
Docket No.:	E002/M-12-0050	
Response To:	Christopher Shaw, Mark Johnson	Information Request No. 3
Requestor:	Dept of Commerce	
Date Received:	March 14, 2012	

Question:
In Docket No. E015/M-10-799, the Commission required Minnesota Power to exclude internal capitalized costs from its TCR Rider. Did Xcel include internal capitalized costs in its TCR Rider? If so, please provide the amount of internal capitalized costs included in the TCR Rider and their impact on the revenue requirement calculations.

Response:
Xcel Energy did include internal capitalized costs in the 2012 TCR Rider, consistent with prior TCR Rider filings and the FERC Uniform System of Accounts and Minn. Stat. 216B.10. FERC rules require labor and overheads associated with the installation of capital projects be categorized as capital expenses not operating expenses. See 18 CFR Ch 1, pt. 101(3)(A)(2).

Please see Attachment A, Page 1, for the internal labor costs with associated labor loadings by project group for 2012. Percentages for CWIP and RWIP were calculated by taking the total internal labor costs (plus associated labor loadings) divided by the total capital charges. These percentages were then applied to all CWIP or RWIP related inputs to reduce the charges in the rider. The revenue requirement impact of the internal capitalized costs starting in 2012 is approximately $1.5 million as shown on Attachment A, page 2.

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Date:	April 25, 2012

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Date:	April 25, 2012

Northern States Power Company, a Minnesota corporation - Electric (State of Minnesota)
Transmission Cost Recovery Rider
Internal Labor total percentage of the project - CWIP & RWIP

Project Group	CWIP Internal Labor w/ Loadings 730390-731250	RWIP Internal Labor w/ Loadings 740399-741250	Total project	Internal Labor total percentage of the project - CWIP	Internal Labor total percentage of the project RWIP
CapX Fargo	9,343,235.27	140,711.95	50,531,792.39	18.49%	0.28%
Chisago Apple Rive	7,757,432.44	207,024.58	47,889,888.55	16.20%	0.43%
CapX Lacrosse	1,706,280.69	0.00	13,327,913.36	12.80%	0.00%
CapX Brookings	1,056,718.55	0.00	32,329,050.03	3.27%	0.00%
CapX Bemidji	316,353.54	0.00	19,180,555.30	1.65%	0.00%
Buffalo Ridge	3,838,030.69	696,990.73	45,230,921.45	8.49%	1.54%
MN 2010 RES	2,242,897.78	105,947.06	7,074,593.50	31.70%	1.50%
SWTC	359,166.17	0.00	1,220,555.07	29.43%	0.00%

The percentages for each applicable project represent the total internal labor costs (plus associated labor loadings) divided by the total capital cha
These costs include life-to-date spend through March 20, 2012. The percentages were further broken out by CWIP and RWIP based on actual act
from the same time periods.

TCR Projected Tracker Activity for 2012	As Filed 2012 Total	2012 With Internal Labor(w Loadings) Excluded	Difference
Project 7 - BRIGO	-	-	-
Project 8 - Chisago Apple River	4,090,362	4,090,362	-
Project 11 - CAPX2020 - Fargo	8,884,268	8,284,921	599,348
Project 12 - CAPX2020 - Brookings	6,458,017	6,357,667	100,350
Project 13 - CAPX2020 - La Crosse 1	302,726	263,996	38,730
Project 13 - CAPX2020 - La Crosse 2	1,818,969	1,756,763	62,206
Project 14 - CAPX2020 - Bemidji	2,685,218	2,178,240	506,978
Project 17 - Pleasant Valley - Byron	355,590	318,889	36,701
Project 19 - Glencoe - Waconia	688,487	512,734	175,753
RECB - Schedule 26	1,420,784	1,420,784	-
Subtotal Transmission Statute Projects	**26,704,421**	**25,184,355**	**1,520,066**
Project 15 - Blue Lake/Wilmarth/Lakefield	-	-	-
Project 16 - Nobles Network Upgrade	-	-	-
Project 18 - Buffalo Ridge Restoration	3,850,813	3,838,817	11,996
Project Amortizations/Expenses	-	-	-
Subtotal Renewable Statute Projects	**3,850,813**	**3,838,817**	**11,996**
Project 9a - SF6 Breaker Replacement	-	-	-
Subtotal Greenhouse Gas Projects	**-**	**-**	**-**
Revenue Requirement in Base Rates	(179,322)	(179,322)	-
Rev Requirement Impact of Project 18 Retirement	(349,625)	(349,625)	-
TCR True-up Carryover	(432,253)	(432,253)	-
Total	$ 29,594,035	$ 28,061,973	$ 1,532,062
Percent of Total MN Jurisdictional TCR Revenue Requirements		94.8%	5.2%

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
Comments

Docket No. E002/M-12-50

Dated this **13th o**f **June, 2012**

/s/Sharon Ferguson

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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