March 4, 2019

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

RE: **Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. G002/M-18-692

Dear Mr. Wolf:

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

> In the Matter of the Petition of Northern States Power Company, doing business as Xcel Energy, for Approval of a Gas Utilities Infrastructure Cost Rider True-up Report for 2018, Revenue Requirements for 2019, and Revised Adjustment Factors (Petition).

The Petition was filed on November 1, 2018 by:

> Lisa Peterson
> Manager, Regulatory Analysis
> Xcel Energy
> 414 Nicollet Mall, 401-7th Floor
> Minneapolis, Minnesota 55401

The Department recommends that the Minnesota Public Utilities Commission **continue to allow Xcel to recover eligible project costs in its GUIC Rider, with modifications.** The Department also recommends that Xcel provide additional information in Reply Comments.

The Department is available to answer any questions that the Minnesota Public Utilities Commission may have.

Sincerely,

/s/ DOROTHY MORRISSEY
Financial Analyst

/s/ DANIELLE WINNER
Rates Analyst

DM/DW/jl
Attachments

COMMERCE DEPARTMENT

Before the Minnesota Public Utilities Commission

Comments of the Minnesota Department of Commerce
Division of Energy Resources

Docket No. G002/M-18-692

I. BACKGROUND

The Gas Utility Infrastructure Cost (GUIC) Recovery Rider was established under Minn. Stat. § 216B.1635. It allows natural gas utilities to commence recovery of certain qualifying projects between general rate cases. Eligible projects can constitute either replacement or modification of existing natural gas facilities, and also can include non-capital expenses such as surveys and assessments. However, to be eligible for recovery through the GUIC Rider, project expenses must meet the following requirements:

- Project costs must be incremental to costs already recovered in base rates;
- Projects cannot serve to increase revenues by connecting new customers to the system; and
- Projects cannot constitute a "betterment" to the system, unless that betterment is required by a political subdivision or federal or state agency.

On August 1, 2014, Northern States Power Company, d/b/a Xcel Energy (Xcel, Xcel Gas or the Company), filed its inaugural GUIC recovery petition requesting approval to establish a rider (2015 GUIC Rider). On January 27, 2015, the Minnesota Public Utilities Commission (Commission) issued an Order Approving Rider with Modifications in Docket No. G002/M-14-336 (Docket 14-336) approving Xcel's proposed 2015 GUIC Rider and tariff sheets with certain modifications.[1] Also in Docket 14-336, the Commission granted recovery of previously approved deferred costs[2] through the GUIC Rider, authorizing a five-year amortization recovery period for the GUIC-qualifying deferred expenditures.[3]

---

[1] Attachment B of Xcel Energy's February 6, 2015 compliance filing in Docket 14-336 shows a $14.7 million revenue requirement for 2015. The final 2015 recovery rate was designed to recover the revenue requirement over an 11-month period, February 2015 – December 2015.

[2] Docket No. G002/M-10-422 (Minnesota Office of Pipeline Safety's required sewer and gas line conflict remediation project) and Docket No. G002/M-12-248 (Xcel's Transmission- and Distribution- Integrity Management Program initiatives).

[3] In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of a Gas Utility Infrastructure Cost Rider, Docket No. G002/M-14-336, Order Approving Rider With Modifications (January 27, 2015), p. 8.

On October 30, 2015, Xcel Gas filed a petition for approval of a 2016 GUIC Rider, Docket No. G002/M-15-808 (Docket 15-808), which included the 2016 GUIC revenue requirement and a prior period true-up. On August 18, 2016, the Commission issued its Order requiring an updated report, approving rider recovery, and requiring metrics to evaluate GUIC expenditures.[4]

On November 1, 2016, in Docket No. G002/M-16-891 (Docket 16-891), Xcel requested approval of a 2017 GUIC Rider to recover the 2017 revenue requirements and its prior-year (2016) true up (2017 GUIC Rider). On February 8, 2018, the Commission issued its Order Approving Rider with Modifications.[5] The Commission authorized a 12-month recovery period effective no sooner than January 1, 2018.

On November 1, 2017, in Docket No. G002/M-17-787 (Docket 17-787), Xcel filed its 2018 GUIC Rider in which the Company requested approval of a 2018 GUIC Rider to recovery its revenue requirements for 2018 and its prior year (2017) true up (2018 GUIC Rider).[6] The 2018 GUIC Rider is pending review and approval by the Commission.

On November 1, 2018, Xcel filed this current petition for approval of its revenue requirements for 2019, and its 2018 true up report (2019 GUIC Rider).

II. PETITION SUMMARY

Xcel Gas requested recovery of its $28.9 million proposed 2019 GUIC revenue requirement over a 12-month period through a rider rate effective January 1, 2020.[7] The proposed 2019 GUIC rider revenue requirement equates to approximately 18.2 percent of the $159.10 million total base rate revenues approved in Xcel Gas's previous general rate case (Docket No. G002/GR-09-

[4]Attachment B of Xcel Energy's August 29, 2016 compliance filing in Docket 15-808 shows a $15.6 million revenue requirement for 2016. The final 2016 recovery rate was designed to recover the revenue requirement over a 15-month period, January 2016 – March 2017.
[5] Attachment B of Xcel Energy's February 20, 2018 compliance filing in Docket 16-891 shows a $20.1 million revenue requirement for 2017. The final 2017 recovery rate was designed to recover the revenue requirement over a 12-month period, March 2018 – February 2019.
[6] Because the 2017 GUIC Rider recovery had not yet been approved at the time of Docket 17-787 filing, the prior-year (2017) true-up report was not available.
[7] Petition, pp. 1, 21, 37. The Company's proposed $28.9 million revenue requirement for 2019 assumes no GUIC tracker carryover balance from prior years.

1153).[8] Xcel's requested $28.9 million revenue requirement was calculated using the Company's proposed return on equity (ROE) of 10.25 percent.[9]

A summary of Xcel Gas's proposed 2019 revenue requirement (from Petition, page 21) is included below:

Table 1. Xcel Gas's Proposed 2019 Gas Utility Infrastructure Revenue Requirements

2019 Gas Utility Infrastructure Revenue Requirements ($ Millions)					
Line #				**2019 Forecast**	
1	*Capital-Related Revenue Requirements*				
2		TIMP		9.49	
3		DIMP		10.76	
4			*SubTotal*		**20.25**
5	*O&M Expenses*				
6		TIMP		2.56	
7		DIMP		2.78	
8			*SubTotal*		**5.34**
9	*5-Year Amortization of Deferred Costs (Year 5)*				
10		TIMP		0.82	
11		DIMP		3.73	
12			*SubTotal*		**4.55**
13	*ADIT Prorate / GUIC Plant Retirement Revenue Credits:*				(0.76)
14	*O&M Recovery in Base Rates:*				(0.48)
15		**Total GUIC Revenue Requirement**			**28.9**

Xcel Gas's requested GUIC revenue requirement reflects cost recovery of its Transmission Integrity Management Program (TIMP) projects, Distribution Integrity Management Program (DIMP) projects, and the amortization of two previously approved deferred cost requests[10] for

[8] Petition, p.33. The $159.10 million excludes gas costs, transportation charges and other operating income. Prior and future years estimated GUIC revenue requirements are summarized in Attachment M of the Petition.
[9] Petition, p. 40.
[10] Petition, p. 21. Deferred costs include implementation of the inspection and remediation of sewer/natural gas line conflicts approved in Docket No. G002/M-10-422 and costs to comply with gas pipeline safety programs approved in Docket No. G002/M-12-248.

work responsive to various regulatory directives; the resulting $28.9 million request included offsets for certain costs already reflected in Xcel's existing base rates. An overview of Xcel's four collective GUIC cost/adjustment categories are discussed next.

A. TRANSMISSION INTEGRITY MANAGEMENT PROGRAM (TIMP)

Integrity management programs were introduced pursuant to the Pipeline Safety Improvement Act, passed by the U.S. Congress in 2002, which directed the U.S. Department of Transportation (USDOT) to promulgate rules to address gas transmission pipelines. Xcel established its TIMP to comply with federal regulations.[11] A TIMP is a prescriptive risk-based program and its goal is to assess the health and condition of a utility's gas transmission assets, and evaluate and prioritize repairs to mitigate the risks and threats.[12]

In general, Xcel's TIMP project activity involves assessing and improving the safety of its gas transmission system, which consists of approximately 74 miles of pipeline in the state of Minnesota.[13] Xcel's current designated TIMP project initiatives include:

- **Transmission Pipeline Assessments**, including in-line inspections (ILI), pressure tests, and direct assessment;
- **Automatic Shutoff Valves (ASV) and Remote Controlled Shutoff Valves (RSV)**, allows more expedient gas shutoff in an emergency; and
- **Programmatic Replacement and Maximum Allowable Operating Pressure (MAOP) Remediation**, program targets capital-intensive repairs or replacement efforts needed on transmission pipelines that have been assessed for asset health and condition in prior years.

B. DISTRIBUTION INTEGRITY MANAGEMENT PROGRAM (DIMP)

The Pipeline and Hazardous Materials Safety Administration (PHMSA) published DIMP rules establishing integrity management requirements for gas distribution pipeline systems in 2009. Xcel established its DIMP to comply with these federal regulations.[14] A DIMP is intended to help gas utilities identify, prioritize, and evaluate risks; identify and implement measures to address risk, and validate the integrity of their gas distribution system.

[11] 49 C.F.R. § 192, Subpart O.
[12] Petition Attachment C, p. 1.
[13] Petition, p. 7.
[14] 49 C.F.R. § 192, Subpart P.

In general, Xcel's DIMP project activity involves assessing and improving the safety of its distribution system located in the state of Minnesota. Xcel's current designated DIMP project initiatives include:

- **Poor Performing Main and Service Replacement**, identify high-risk pipeline segments and prioritizing their replacement in concert with city and county road maintenance;
- **Intermediate Pressure Pipeline Assessments**, determine the health and condition of medium-sized distribution pipelines;
- **Sewer and Gas Line Conflict Investigation**, identify and correct situations where natural gas lines intersect with sewer lines; this project is expected to be completed in 2019; and
- **Distribution Valves Replacement**, maintain Xcel's ability to isolate sections of the system in case of an emergency. Due to resource limitations and permitting issues, some project work has been delayed into 2019.[15]

C. DEFERRED COST AMORTIZATIONS

The Commission approved the inclusion and recovery of two previously approved deferral requests through the GUIC Rider.[16] Herein, the year 2019 marks the fifth and final year of the approved 5-year amortization of these deferred costs included in the GUIC revenue requirement determination.

The approved deferred accounting in Docket G002/M-10-422 captured and deferred costs related to the sewer and natural gas pipeline conflicts. These costs were incurred to comply with Minnesota Office of Pipeline Safety (MNOPS) Notice of Probable Violation issued to Xcel Gas in response to an incident where property damage and personal injury occurred due to a natural gas line intersecting a sewer line.

Prior to Xcel establishing its GUIC Rider, the approved deferred accounting in Docket G002/M-12-248 captured and deferred incremental operating and maintenance costs incurred to comply with gas transmission and distribution pipeline safety programs. The majority of these accumulated deferred costs were integrity program expenditures on the Company's gas transmission system, with a smaller portion arising from gas distribution system work.[17]

---

[15] DOC IR No. 14 included in DOC Attachment 1.
[16] Docket No. G002/M-14-336.
[17] The majority of these deferred costs were expenditures on the gas transmission system, with a smaller portion attributed to gas distribution system work, see Docket No. G002/M-14-336, April 24, 2014 Compliance Filing, Attachment D.

D. OFFSETS TO GUIC RIDER REVENUE REQUIREMENTS

Per Minn. Stat. § 216B.1635, the GUIC Rider rate is to recover only incremental costs. Therefore, to achieve only incremental cost recovery through the GUIC rider, base rate revenue requirement offsets (i.e., adjustments) are included to account for costs already being recovered through existing rates.

Table 1 above showed two adjustments, $(0.76) million and $(0.48) million. The $(0.76) million adjustment accounts for the capital-related costs. Many GUIC projects replace or modify existing natural gas facilities. This adjustment recognizes that the Company's base rates include recovery of costs associated with those facilities, now retired due to GUIC project work. The $(0.48) million operating and maintenance (O&M) adjustment reflects the TIMP-related expenses that were built into Xcel Gas's base rates.[18] By accounting for the revenue requirement of these costs imbedded in the Company's base rates and adjusting them out from the gross GUIC project work revenue requirements, an incremental revenue requirement for the rider is established.

Collectively, these four general GUIC cost/adjustment categories inform Xcel Gas's requested 2019 revenue requirement of $28.9 million. Xcel proposed to allocate the revenue requirements within the 2019 GUIC Rider to its various customer classes in the same manner as revenue responsibilities were apportioned in its most recent natural gas rate case,[19] consistent with the Commission's previous GUIC orders.[20] As proposed, the 2019 GUIC rider's impact on the average residential customer's bill would be an approximate $3.74 charge per month.[21] Further details of Xcel's proposed billing factors for each customer class are provided on page 36 of Xcel's Petition (Xcel Table 5).

III. DEPARTMENT ANALYSIS OVERVIEW

A. STATUTORY BACKGROUND AND FILING REQUIREMENTS

Generally, a public utility may not change its rates without undergoing a general rate case in which the Commission comprehensively reviews the utility's costs and revenues. However, the Legislature created exceptions to this general policy, allowing a utility to implement specific

---

[18] Base rate inclusions are summarized in Xcel's petition in Docket No. G002/M-12-248, pp. 6-7 and 9-10.
[19] Docket No. G002/GR-09-1153.
[20] January 27, 2015 *Order* in Docket No. G002/M-14-336; August 18, 2016 *Order* in Docket No. G002/M-15-808; and February 8, 2018 *Order* in Docket No. G002/M-16-891.
[21] Petition, p. 36. $3.74 = 72 * $0.051938 per therm. The average Xcel residential customer consumes 72 therms of gas per month. The proposed 2019 GUIC factor for residential customers is $0.051938 per therm.

riders with rate-adjustment mechanisms to expedite recovery of certain costs not reflected in the utility's current base rates.

Minnesota Statute § 216B.1635 allows utilities to seek rider recovery of gas utility infrastructure costs. Gas utility infrastructure costs are costs that are *not* included in the gas utility's rate base in its most recent general rate case, which the utility incurred from gas infrastructure projects involving (1) the replacement of natural gas facilities required by road construction or other public work by or on behalf of a government agency, and (2) the replacement or modification of existing facilities required by a federal or state agency, including incremental costs of surveys, assessments, reassessment, and other work necessary to determine the need for replacement or modification of existing infrastructure.[22] The Department notes that the Commission interpreted this Statute in its January 27, 2015 *Order* in Docket 14-336 that a gas infrastructure project is eligible for rider recovery under Minn. Stat. § 216B.1635 if *either* subpart (1) or (2) are satisfied. Projects that constitute a "betterment" do not qualify for rider recovery unless the betterment is "based on" requirements by a political subdivision or a federal or state agency.[23]

A utility seeking approval of a GUIC Rider must file a petition with the Commission detailing the projects and costs proposed for recovery.[24] The petition for rate recovery is to be of only incremental costs.[25] The utility must file sufficient information to satisfy the Commission regarding the reasonableness of the proposed gas utility infrastructure costs, including, but not limited to, the following:

- Project description and scope, estimated costs, and in-service date;
- The government entity ordering or requiring the project and the purpose for which the project is undertaken;
- A description of the estimated costs and salvage value, if any, associated with the existing infrastructure replaced or modified as a result of the project;
- A comparison of the utility's estimated costs and the actual costs incurred, including a description of the utility's efforts to ensure that the costs of the facilities are reasonable and prudently incurred;
- Calculations to establish that the rate adjustment is consistent with the terms of the rate schedule, including the proposed rate design and an explanation of why the proposed rate design is in the public interest;

[22] Minn. Stat. § 216B.1635, Subd. 1(b), (c).
[23] Minn. Stat. § 216B.1635, Subd. 1(b) (3).
[24] *Id.*, Subd. 2-3.
[25] *Id.,* Subd. 2

- The magnitude and timing of any known future projects that the utility may seek to recover under the GUIC statute;
- The magnitude of the costs in relation to the utility's base revenue as approved by the Commission in the utility's most recent general rate case, exclusive of gas-purchase costs and transportation charges;
- The magnitude of the costs in relation to the utility's capital expenditures since its most recent general rate case; and
- The amount of time since the utility last filed a general rate case and the utility's reasons for seeking recovery outside of a general rate case.[26]

The Commission may approve a GUIC Rider if the costs proposed for recovery through the rider are prudently incurred and achieve gas facility improvements at the lowest reasonable and prudent costs to ratepayers.[27] Costs eligible for rider recovery include a rate of return, income taxes on the rate of return, incremental property taxes, incremental depreciation expense, and any incremental operation and maintenance costs.[28]

Xcel included a compliance matrix for the filing requirements specified in Minn. Stat. § 216B.1635 and in prior Commission orders (summarized in Attachment A to its initial *Petition*) along with identification of specific projects in Attachments such as C, C1, C2, D, D1(a)-D1(j).

The Department concludes that Xcel Gas's filing reasonably complies with the filing requirements.

B. PROJECT ELIGIBILITY

Gas utility infrastructure projects required by road construction or other public work by or on behalf of a government agency, or that are required by a federal or state agency are eligible for GUIC Rider recovery.[29] By Commission Order,[30] Xcel is required to disclose in its GUIC petitions the agency, regulation or order that requires the Company's proposed projects.[31] Xcel's Petition includes projects previously approved for recovery in earlier GUIC filings and does not propose new projects. Since the projects included in the Petition have already been reviewed by the Commission, and absent new information to the contrary, the Department concludes that the projects are eligible for GUIC recovery.

---

[26] *Id.*, Subd. 4.
[27] *Id.,* Subd. 5.
[28] *Id.*, Subds. 2 and 4.
[29] *Id.,* Subd. 1.
[30] Docket No. G002/M-15-808, Order issued August 18, 2016.
[31] Petition, Attachment A, p. 6, Requirement 6.

C. ISSUES IDENTIFIED

The Department conducted its review of the Company's Petition and raises several issues with Xcel's proposal. The following issues are discussed separately in the next section.

1. *Sales Forecast*
2. *Rate of Return*
3. *The Tax Cuts and Jobs Act of 2017*
4. *Sewer and Natural Gas Line Conflict Rider Recovery Amount*
5. *GUIC Retired Facilities Revenue Credit*
6. *Prorated Accumulated Deferred Income Tax (ADIT) For Rate Base Determination*
7. *Carrying Charge on Unrecovered GUIC Rider Recovery Tracker Balance*
8. *DIMP - Costs for Low-Risk Infrastructure Work Done in Conjunction with Higher Risk GUIC-Eligible Work*
9. *Removal Costs Impact on GUIC Recovery Request*
10. *TIMP – Programmatic Replacement And MAOP Remediation*
11. *Internal Capitalized Costs*
12. *Risk Assessment and Performance Metrics*

IV. DEPARTMENT ISSUES

A. SALES FORECAST

In Xcel's GUIC Rider, the sales forecast is used to project gas consumption for each customer class over the time the proposed GUIC Rider is expected to be in place. The projected sales for each class is important as it is used, in part, to determine the proposed 2019 GUIC rate for each class, given each class's 2019 GUIC revenue requirement. The sales forecast needs to be reasonable since a sales forecast that is too low will cause rates to be too high, and the Company will over-recover its revenue requirement. If the sales forecast is too high, rates will be set too low, and the Company will under-recover its revenue requirement.

Xcel's proposed 2019 GUIC Rider has a carry-over (or true-up) mechanism for over- and under-recoveries, and so, theoretically, any mismatch should be corrected in a presumed 2020 GUIC Rider. Due to the true-up mechanism, the consequences of an inaccurate sales forecast in the GUIC Rider are not quite as dire as they would be for an inaccurate sales forecast in setting base rates. Nonetheless, in an already complex filing such as the GUIC Rider, the Department notes that minimizing the number and amount of adjustments is desirable because it eliminates revenue mismatches between years and provides ratepayers with the most reasonable approximation of rider-related costs for the recovery period.

In Xcel's 2017 GUIC Filing, the Commission directed the Company to remove two modifications that Xcel included in the sales forecast. The first was a monthly historical sales adjustment that effectively "smoothed" the Company's data. The second was an adjustment for demand-side management (DSM) energy savings. In its 2018 GUIC Filing, Xcel removed the DSM adjustment, and, at the Department's recommendation, removed the monthly historical adjustment.

However, in the 2018 GUIC Filing, the Department noted a material mismatch of forecast data in the GUIC and historical data reported in the Company's Gas Jurisdictional Annual Report (GJAR). The Department noted that the Company's GUIC sales forecast was much lower than the actual sales reported in the Company's GJAR. In Response Comments, the Department stated:

> The Department also asked Xcel to explain why the Company's projected 2018-2019 sales data used in the Company's forecast was significantly lower than the actual 2016-2017 data reported in Company's Gas Jurisdictional Annual Reports (GJAR). In Reply Comments, Xcel stated that this discrepancy was largely due to a projected decrease in the transportation classes. Specifically, the Company stated that there is a projected decrease in interdepartmental transportation gas sales used for electricity generation. The Company predicted that with the more efficient production of electricity at the Mankato and Black Dog plants, as well as the increase of renewables on the system, gas sales put towards electricity generation will decrease. Finally, the Company stated that in future GUIC petitions, it will include a discussion of any major drivers of gas sales increases or decreases in the forecast. The Department notes that, while it is possible that there may be a reduction in natural gas sales to the Mankato and Black Dog generation facilities, there are numerous factors that may affect the dispatch of those facilities by the Midcontinent Independent System Operator (MISO). Thus, the Department recommends that the Commission require Xcel to use the most recent 12 months of actual natural gas sales to allocate the costs across jurisdictions and classes. If there is a reduction in natural gas sales, that reduction would be reflected in subsequent GUIC factors.[32]

[32] Docket No. G002/M-17-787, Department Response Comments.

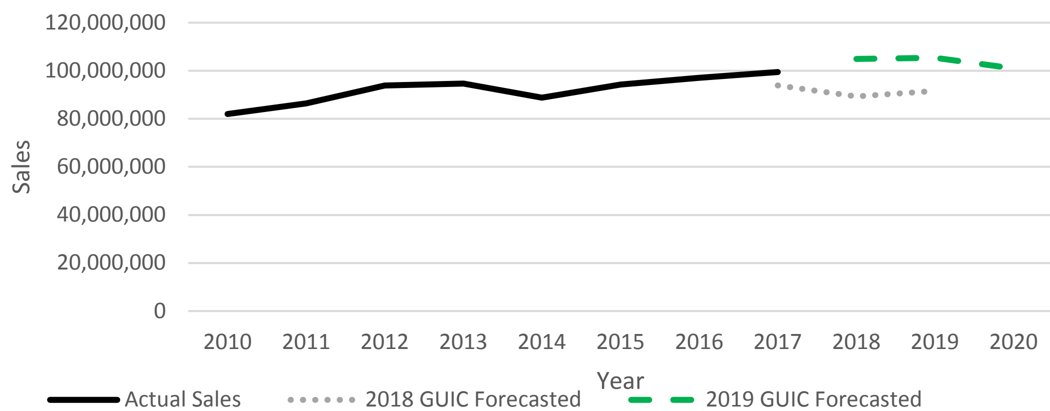
At the time of these comments, the 2018 GUIC Rider docket has not been heard by the Commission; as such, this issue remains unresolved. In this current docket, the Department is unable to examine the 2018 GJAR, because it is not filed until May 1, 2019. However, the following table shows the Company's historical sales figures versus projected sales in the 2018 and 2019 GUIC Riders:

Table 2. Xcel Gas Historical Sales versus Projected Sales in 2018 and 2019 GUIC Filings[33]

Year	Average Number of Customers/Month	Actual Weather-Normalized Calendar Month Sales (Dth)	2018 GUIC Forecasted Weather-Normalized Calendar Month Sales (Dth)	2019 GUIC Forecasted Weather-Normalized Calendar Month Sales (Dth)
2010	432,820	82,002,544		
2011	435,377	86,442,266		
2012	437,606	93,916,985		
2013	440,316	94,699,234		
2014	443,676	88,811,160		
2015	447,933	94,301,426		
2016	451,720	97,104,355		
2017	455,095	99,469,703	93,889,110	
2018	459,470		89,314,493	104,962,465
2019	462,893		91,556,339	105,387,223
2020	465,603			100,972,189

[33] DOC IR No. 29 in G002/M-17-787, DOC IR No. 39 in G002/M-18-692.

Figure 1. Xcel Gas Historical Sales versus Projected Sales in 2018 and 2019 GUIC Filings



Xcel's projected sales included in the 2019 filing appear to be much more appropriate, from a general perspective, relative to the information in the 2018 GUIC filing. However, the Department is still unsure why Xcel attempted to capture a decrease in sales in the transportation class, or whether Xcel continued to make this assumption in the 2019 filing. The Department recommends that Xcel clarify in its Reply Comments whether the Company assumed, or included, any other cost drivers in its data and projections.

Further, while the average customer count in the above table reflects calendar months for years 2010-2017, the Department believes the information for 2018-2020 represents average customer counts for billing months. It is unclear whether the Company converts the number of billing month customers to calendar month customers at some point in the forecasting process, or uses the billing and calendar month figures interchangeably. As such, the Department recommends that the Company clarify, in Reply Comments, if billing month customer count numbers are converted to calendar month average customer counts in the forecasting process.

The Department also reviewed the Company's sales forecast data, assumptions, and statistical outputs underlying the above figures, and concludes that they are generally reasonable. The Company appears to have appropriately left out both the DSM and monthly historical adjustments that the Department critiqued in past GUIC filings. The Company also included weather normalization and billing/calendar month adjustments, both of which appear to be reasonable. The Department was able to recreate the Company's results from the Residential and Commercial customer classes, given data and variables used, even with differences in statistical software packages. The Department will continue to verify the Company's results for each customer class.

The Department concludes that the Company's 2019 GUIC sales forecast is generally reasonable. However, the Department would like to understand the Company's 2018 GUIC Interdepartmental Transportation class assumptions and the average customer count calendar versus billing month assumption, as discussed above. The Department recommends that the Company address each of these issues in Reply Comments.

B. RATE OF RETURN

The GUIC statute provides that "[t]he return on investment for the rate adjustment shall be at the level approved by the [C]ommission in the public utility's last general rate case, unless the [C]ommission determines that a different rate of return is in the public interest."[34] In compliance with this statutory directive, the Commission has set the authorized overall rate of return (ROR) in prior GUIC dockets at 7.57%, 7.34%, and 7.02% for the years 2015, 2016, and 2017, respectively. In each year, the Commission has used the same capital structure and authorized cost of debt (taken from Xcel's 2013 electric rate case, Docket No. E002/GR-13-868), only updating the authorized return on common equity (ROE), from 10.09% in 2015, to 9.64% in 2016, and 9.04% in 2017.[35]

In the 2018 GUIC Rider, Xcel proposed to again maintain the authorized short and long term costs of debt used for past years, but update the authorized ROE to 10.00%, resulting in an overall authorized ROR of 7.52%. The Department did not support Xcel's proposal and instead supported maintaining the authorized ROR at 7.02%, as approved for the 2017 GUIC Rider in February, 2018.

In the instant docket, Xcel again proposed to use the same short term cost of debt and long term cost of debt approved in Xcel's 2015 Electric Rate Case (Docket No. E002/GR-15-826), but to use a 10.25% return on equity.

The Department is not opposed to using the capital structure approved in the Company's 2015 electric rate case, but opposes the Company's proposal to alter the ROE from the approved 9.04% the Commission approved in the Company's 2017 GUIC. That docket provides the most up-to-date cost of equity for Xcel Gas authorized by the Commission.[36]

---

[34]Minn. Stat. 216B.1635, Subd. 6.
[35]The Commission's *Order* dated February 8, 2018 in Docket No. G002/M-16-891 approved this rate, based on the Department's extensive review of the 2017 information and recommended updated rate of return.
[36] The Department further notes, as it did in the 2018 GUIC Filing, that it does not have resources to conduct full ROR analyses on each yearly rider proposed by each utility, nor does the GUIC statute require such analysis.

The Department concludes that keeping the 2019 GUIC ROR at the approved 2017 levels is a more efficient use of regulatory resources, is consistent with the GUIC statute, and allows for consistency with other riders and within the GUIC. The Department further concludes that the Company has not demonstrated how changing the ROR from the level set by the Commission for Xcel's 2017 GUIC would be in the public interest.

Therefore, the Department continues to recommend that the Company maintain the ROR and capital structure at the levels approved in the 2017 GUIC Rider.

C. THE TAX CUTS AND JOBS ACT OF 2017

On December 22, 2017, Pub Law 115-97 (known as the Tax Cuts and Jobs Act of 2017, or TCJA), took effect, reducing the marginal federal corporate income tax rate from 35 percent to a flat 21 percent, effective January 1, 2018.[37] This enactment constituted a known and measurable change for Minnesota rate-regulated utility rates going forward.

On December 29, 2017, the Minnesota Public Utilities Commission (Commission) issued its Notice of Commission Investigation into the Effect of the 2017 Federal Tax Act on Utility Rates and Services in Docket No. E,G999/CI-17-895 (Tax Docket). The Tax Docket was before the Commission at its August 9, 2018 Agenda Meeting. The Commission required utilities to refund all impacts of the TCJA to ratepayers. This requirement included changes to current period tax expense on the income statement, changes to the tax gross-up on the revenue requirement deficiency, and the amortization of excess accumulated deferred income tax (excess ADIT or EDIT) balances. In addition, the Commission required utilities to separately incorporate the effects of the TCJA in each rider mechanism.

Xcel's GUIC Petition Attachments G and H show that the Company is using the appropriate federal income tax rate in calculating tax expense and the tax gross-up factor. However, the Company's schedules do not show the amount of the GUIC Rider's excess accumulated deferred income tax balance, nor show whether or not any amortization of excess accumulated deferred income tax was included when determining revenue requirements. In response to an information request, Xcel stated, in part, that:

> The Company has included amortization of EDIT in the GUIC rider revenue requirement starting in 2018. The ADIT balances on petition schedules G and H contain both current ADIT and EDIT. The flow back of the EDIT to customers […] begins when book depreciation for specific assets exceeds tax depreciation. […][38]

---

[37] See H.R. 1—115th Congress: AN ACT TO PROVIDE FOR RECONCILIATION PURSUANT TO TITLES II AND V OF THE CONCURRENT RESOLUTION ON THE BUDGET FOR FISCAL YEAR 2018.
[38] DOC IR No. 40 included in DOC Attachment 2.

The Department requests that the Company revise their rider petition schedules G and H to breakout the ADIT balance and separately identify:

- the excess ADIT (i.e., EDIT) balance, due to the TCJA, that is to be returned to ratepayers and
- the amortized amount of the EDIT being included in the GUIC revenue requirement.

These additional reporting details will increase transparency and allow stakeholders to confirm that all the benefits of the federal tax reform are reflected in rates.

In addition, the Department requests that Xcel include in its Reply Comments a discussion of the EDIT amortization technique/method it will use in the GUIC Rider and whether the procedure is consistent with the technique/method applied to its base rates' EDIT amortization and refund to ratepayers. If the amortization of the GUIC Rider EDIT has not yet begun, the Company's Reply Comments should explain why and when the EDIT refunding will commence.

D. SEWER AND NATURAL GAS LINE CONFLICT RIDER RECOVERY AMOUNT

The Company began its Sewer and Gas Line Conflict Investigation program in 2010, inspecting sewer laterals and mains for conflicts, and anticipated it to be a 10-year program.[39] Xcel Gas included in the proposed 2019 GUIC revenue requirements $2.15 million in O&M expenses for current year sewer and natural gas line conflict inspections program work.[40] In addition, the amortized portion of this program's deferred costs included in the 2019 GUIC revenue requirement is approximately $3.7 million.[41]

In response to DOC IR No. 41, Xcel described the following four categories of the Company's sewer and gas line inspection work:[42]

- *Legacy Projects* –sewer inspection and mitigation work covered under the Commission-approved cost deferral mechanism, authorized in Docket No. G002/M-10-422;
- *Emergency* – requests for inspection that are received from a customer, community, plumber, and other external resources;
- *Cleared by Maps* – refers to potential conflict areas identified by using gas map and as-built records that are compared to information available from communities served; and

[39] Docket No. G002/M-14-336, Petition, Attachment 3, p. 8 (August 10, 2014).
[40] Petition, Attachment D, pp. 3, 9.
[41] Petition, Attachment K.
[42] DOC IR No. 41 included in DOC Attachment 3.

- *New Construction* – refers to new gas installations (after January 1, 2010) cleared prior to introducing gas to these newly installed facilities.

Xcel's response stated that only the costs for the first three categories of work (Legacy Projects, Emergency, and Cleared by Maps) are included in its GUIC Rider cost recovery request.

In Xcel Gas's 2010 petition requesting deferred accounting treatment for its sewer/gas line inspection work plan (Docket 10-422), the Company estimated that $50,000 was included in its 2010 test year distribution O&M budget for "performing sewer investigations in response to customer and/or contractor requests."[43] The 2010 test-year was used to set Xcel Gas's existing base rates. This base-rates-described activity is the same description of the Emergency category work above, which in its DOC IR No. 41 response Xcel identified as one of the work category costs that are included in the Company's GUIC request. Further, in Docket 10-422, the Company committed to segregate its Plan/Program costs to be deferred from these "normal conflict investigation costs incurred as part of our daily operations."[44]

However, the Company did not include any adjustments to its current or prior GUIC revenue requirement for costs included in its base rates for sewer inspection work; therefore, the Department concludes that Xcel included in its proposed Rider costs that are already represented in its base rates, and would thus result in double recovering certain operating expenses if approved.

Consequently, the Department recommends that Xcel reduce its 2019 GUIC Rider revenue requirement by $50,000 to account for the cost of sewer inspection work included in its current base rates, and continue such an adjustment in its prospective GUIC petitions corresponding to the amount included in base rates. Further, if Xcel, in its Reply Comments, cannot provide verifiable support that its Docket 10-422 deferred Sewer and Gas Line Inspection Plan cost amount (now being amortized) excluded costs for the sewer conflict investigation costs incurred as part of its daily operations, the Department may have additional adjustments.

E. GUIC RETIRED FACILITIES REVENUE CREDIT

Xcel included a $0.76 million reduction in its 2019 GUIC Rider revenue requirement calculation to account for the imbedded cost recovery of gas facilities in base rates, which were based on a 2010 test year,[45] now retired due to GUIC projects. This adjustment is done in an effort to include only incremental costs in the rider recovery mechanism and thus avoid double-recovery

---

[43] Docket No. G002/M-10-422, Initial Petition, p. 5 (May 3, 2010).
[44] Ibid, p. 6.
[45] Docket No. G002/GR-09-1153.

of costs. The Department appreciates Xcel's efforts in this regard. The Company summarized the make-up of the total $(0.76) million revenue requirement impact in Xcel Table 1 within its Petition, which is replicated below:

Table 3. Xcel Gas's Proposed 2019 GUIC Plant Retirement Revenue Credit

GUIC Plant Retirement Revenue Credit		
Revenue Requirement Impact – GUIC Replaced Assets ($ millions)		
1	Net Book Value of Retired Assets	$3.09
2	Reduced by ADIT on Retire Assets	(0.70)
3	Rate Base	$2.39
4	Rate of Return on Rate Base	$0.31
5	Estimated Book Depreciation on Retired Assets	0.30
6	Annual Deferred Tax Impact	(0.02)
7	Estimated Property Tax on Retired Assets	0.17
8	Revenue Requirement Impact (sum lines 4 – 7)	$0.76

The Revenue Requirement Impact is to reflect the portion of the 2010 test-year costs used to set the current tariffed base rates, relevant to GUIC replaced assets. The Department requested Xcel to explain the inclusion of the component Annual Deferred Tax Impact of $(0.02) million (Table 3, Line 6) in this calculation. In its response to DOC IR No. 46.B, Xcel stated that the $(0.02) is the estimated 2019 deferred tax amount that would have been incurred had the retired assets still been in-service.[46] The Department recommends that this component not be included to determine the total Revenue Requirement Impact of facilities, now retired due to GUIC project work, because the annual deferred tax impact related to the setting of base rates for these facilities is already included via the Rate of Return on Rate Base amount.

In Table 3 above, Line 4 shows the amount $0.31 million for the rate of return on rate base; this value includes the revenue gross-up of the authorized return, "gross-up" meaning it includes the relative income tax expense ascribed to these assets while in-service. The income tax expense comprises an annual amount of both the current and the deferred tax expense amounts.

The Department recommends that Xcel remove the component "Annual Deferred Tax Impact" when determining the GUIC Plan Retirement Revenue Credit. This recommendation will decrease the overall 2019 GUIC Revenue Requirement by $0.02 million.

[46] DOC IR No. 46.B included in DOC Attachment 4.

F. PRORATED ACCUMULATED DEFERRED INCOME TAX (ADIT) FOR RATE BASE DETERMINATION

Xcel Gas prorated accumulated deferred income tax (ADIT) to determine the rate base component value using the Company's new methodology presented in its Reply Comments filed in the prior 2018 GUIC Rider petition (Docket 17-787).[47] The new methodology results in an ADIT prorate adjustment that has very little impact to customer rates.

It is the Department's understanding that prorated ADIT, a normalization requirement instituted by the Internal Revenue Service, is invoked when the rate becomes effective prior to the conclusion of the forecasted period. In this Petition, Xcel proposed that the 2019 GUIC Rider rate go into effect January 1, 2010, which is after the 2019 period upon which the 2019 GUIC Rider rate is based.[48] Although Xcel's new methodology to calculate a prorated ADIT has very little impact to its 2019 GUIC revenue requirement ($188),[49] the proration procedure is unnecessary because the rate's effective date commences after the test-period. In its response to an information request, Xcel stated that proration is not required and indicated it would reduce the GUIC revenue requirements accordingly in its final compliance.[50]

The Department appreciates Xcel's cooperation to incorporate this revision in its current and any applicable future GUIC petition filings, as well as applicable GUIC rider true-up calculations and reporting.

G. CARRYING CHARGE ON UNRECOVERED GUIC RIDER RECOVERY TRACKER BALANCE

Xcel stated in its petition that, as their GUIC filing continues to grow larger and more complex, it stood to reason that the need for a lengthy review process would continue, and as such, the Company proposed to start recovery of its 2019 GUIC revenue requirement in January 2020. But, in conjunction with this "voluntary delay", Xcel is requesting to include in its revenue requirement a carrying charge on the monthly unrecovered GUIC Rider recovery tracker balance starting in January 2020.[51] The Company proposed the carrying charge rate to be set to its current weighted average cost of capital.

The Department opposes the installation of a carrying charge for several reasons. First, the GUIC Rider mechanism is an optional recovery tool availed to natural gas utilities, which

---

[47] Petition, p. 35.
[48] Petition, p. 37.
[49] Petition, p. 36 and Attachment R.
[50] DOC IR No. 16 included in DOC Attachment 5.
[51] Petition, p. 38.

permits utilities to begin recovery of eligible costs sooner than its next general rate case. The Company could elect to forgo use of this extraordinary rate tool and rather, when they find it necessary, file and request a general rate increase.

Second, the Company has control over the magnitude and complexity of its GUIC petitions. That is, Xcel Gas could elect to file a general rate case and have most, if not all, of the GUIC projects' costs rolled into its base rates, thereby effectively reducing the size and complexity of prospective GUIC Rider petitions. To provide the Commission perspective, in Xcel Gas's last general rate case, the Commission approved a revenue requirement increase of approximately $7.29 million; herein, the Company's $28.9 million rider revenue requirement request is nearly four times (396% higher) than that of its last approved general rate case increase. This is Xcel Gas's fifth successive GUIC petition without a general rate case.

Third, unlike base rates, the GUIC Rider mechanism is subject to true-up. Due to the unique nature of rider true-ups, the utility is assured of realizing full recovery of its approved costs, including the rate of return on equity. This extraordinary recovery tool's true-up feature makes a rider an attractive recovery mechanism, even without carrying charges, because a true-up eliminates a significant amount of risk exposure the utility would otherwise face if all costs were recovered via base rates. This reduction of risk that the rider mechanism offers may be considered valuable recompense even if the rider rate commences post test-year.

Fourth, because the Commission has not imposed an end-date to an approved rider rate, the Company continues to realize a revenue stream, even while a pending rider petition is processed.

Fifth, the Company's plant-in-service amounts include financing costs incurred while projects were under construction and prior to plant being placed into service;[52] thus the utility recovers its GUIC projects' pre-implementation financing costs through the rider rate.

For all the reasons discussed above, the Department recommends that the Commission deny Xcel Gas's request to include a carrying charge. However, should the Commission approve the implementation of a carrying charge, the Department recommends that the Commission set the carrying charge no higher than the cost of short-term debt and make clear that it would be applied symmetrically, that is to both under- and over-recovered tracker balance situations, not just to an under-recovered position.

---

[52] DOC IR No. 38 included in DOC Attachment 6. AFUDC – Allowance for Funds Used During Construction is the capitalization of financing costs for construction work in progress (CWIP).

H. DIMP - COSTS FOR LOW-RISK INFRASTRUCTURE WORK DONE IN CONJUCTION WITH HIGHER RISK GUIC-ELIGIBLE WORK

The Company included in its GUIC Rider request cost recovery for low-risk infrastructure work that was done in conjunction with higher-risk GUIC-eligible work. The Company identified that only its DIMP Poor Performing Mains and Services Program projects may include low-risk infrastructure replacement (or renewal) while undertaking a higher risk project.[53]

In 2019, the Company estimated it will incur total of $16.4 million in DIMP capital expenditures, all of it being spent on its DIMP Poor Performing Mains and Services Program.[54] In prior years, the majority of Xcel's DIMP capital expenditures also have been for this program, as shown below:

Table 4. Xcel Gas Historical Poor Performing Mains and Services Spending Relative to Historical Spending on All DIMP Projects

DIMP Poor Performing Mains and Services Replacement		**All DIMP Projects**	
Year	Capital Expenditures ($ - millions)	Total Capital expenditures ($-millions)	Docket Reference and Xcel Attachment
2015	$10.8	$14.3	16-891, Attachment C1(a)
2016	$16.6	$17.3	17-787, Attachment D1(a)
2017	$17.0	$17.7	18-862, Attachment D1
2018	$18.8	$34.8	18-862, Attachment D1

Given the magnitude of DIMP resources being devoted to this program and the discovery that this program has included costs for low-risk work, it is important to evaluate Xcel's requested ongoing inclusion of these program costs in its GUIC request.

In its response to DOC IR No. 47, Xcel stated that doing the additional low-risk work in conjunction with this DIMP program minimizes disruption to the local community, can streamline the construction process, resulting in more efficient and cost-effective replacement.[55] The Company indicated that at times, replacing low-risk infrastructure can reduce cost of the eligible GUIC higher-risk project that would otherwise be incurred had the

[53] DOC IR No. 47 included in DOC Attachment 7.
[54] Petition, Attachment D at 3 and Attachment W at 2 ($10.1 million + $6.3 million for DIMP Poor Performing Mains and Service Replacements, respectively).
[55] DOC IR No. 47 included in DOC Attachment 7.

low-risk infrastructure remained in place due to eliminating need for additional activity, such as excavations, reclamations, or tie-ins to existing low-risk infrastructure.

In the Company's prior, pending GUIC filing, Docket 17-787, the Department recommended that cost for low-risk work be excluded from GUIC rider mechanism. For the reasons discussed next, the Department again recommends similar action, with modification, in this petition.

First, the expenditures on low-risk infrastructure replacement are elective, and not supported by or responsive to civic/public work requirements or government regulations, and therefore would not be eligible for recovery through the GUIC rider mechanism per Minnesota statute [Section 216B.1635, Subd. 1(c)]. Whether that low-risk work is carried out within a GUIC eligible project site/area or done geographically apart from GUIC project jobsite, low-risk infrastructure replacement not supported by civic/public work requirements or required by government regulations is not eligible for inclusion in the GUIC Rider. The proximity of low risk work to a GUIC-eligible project does not make low-risk project work eligible for inclusion in the GUIC Rider.

In addition, the Department expects that Xcel would continue to undertake capital investment work on its existing system as part of the ordinary course of business, as the Company continues to charge ratepayers for costs of such work. A representative level of costs for such work is already being charged to ratepayers through base rates and thus such costs are not eligible to be charged to ratepayers again through the GUIC mechanism.

The Department understands that in some situations, replacing the low-risk infrastructure may actually lower the higher-risk project's overall cost when compared to what the overall higher-risk project would have cost had it retained use of the existing low-risk infrastructure. It is clear in the governing statute that the elective, low-risk work is not recoverable through the GUIC Rider mechanism. Yet to the extent that Xcel Gas can demonstrate that the total project cost to exclusively perform required work, and retain use of existing low-risk infrastructure, is more than the total cost to conduct and perform required work in a manner that contemporaneously replaces low-risk infrastructure as well, then inclusion of costs attributed to low-risk work may be reasonable to include in the rider. In such circumstances, Xcel would also need to include a higher credit to reflect costs of "low-risk" facilities recovered in base rates. Conversely, to the extent that the total project cost including low-risk infrastructure work exceeds the total cost to exclusively perform required work, if retaining use of existing low-risk infrastructure, than the excess cost should be excluded from the GUIC Rider.

To date, Xcel has not made any such demonstration. Therefore, the Department recommends that the Commission direct Xcel to exclude from its 2019 GUIC Rider recovery request the revenue requirements above the amount(s) that would have otherwise occurred had the project been completed without replacement of the low-risk infrastructure. In its GUIC filings for the applicable projects, the Company should report and fully explain the cost bids of the higher-risk required project work with and without replacement of low-risk infrastructure. The Company should retain and have available upon request verifiable supporting documents of these cost comparisons.

I. REMOVAL COSTS IMPACT ON GUIC RECOVERY REQUEST

It is the Department's understanding that the Company included the retired plant's removal cost impact in its GUIC Rider request. Referring to its TIMP and DIMP capital-related revenue requirement schedules (Attachments G and H), the Department requested the Company to quantify the amount included in each rate base component relevant to these removal costs.[56] In response to DOC IR No. 20, the Company provided, in part, the following:

Table 5. Impact of Removal Costs on TIMP Rate Base Components For Years 2017 - 2019

TIMP Removal Costs Only				
Rate Base Component	**Total 2017**	**Total 2018**	**Total 2019**	**Total 2020**
Accumulated Book Depreciation Reserve	$(1,359,907)	$(6,467,205)	$(6,609,370)	$(7,165,834)
Accumulated Deferred Taxes	3,493,218	2,996,700	3,161,616	3,353,876
Net End of Month Rate Base	$(2,133,311)	$3,470,505	$3,447,754	$3,811,958

Table 6. Impact of Removal Costs on DIMP Rate Base Components For Years 2017 - 2019

DIMP Removal Costs Only				
Rate Base Component	**Total 2017**	**Total 2018**	**Total 2019**	**Total 2020**
Accumulated Book Depreciation Reserve	$(6,952,476)	$(8,173,186)	$(9,629,824)	$(10,530,674)
Accumulated Deferred Taxes	3,483,281	3,735,393	3,990,250	3,483,281
Net End of Month Rate Base	$4,689,904	$5,894,432	$6,540,424	$4,689,904

In review of both the TIMP and DIMP data, the relationship between the removal cost amount reported in *Accumulated Book Depreciation Reserve* and the *Accumulated Deferred Taxes* amount within each year is not clear. The Department requests that in Reply Comments, Xcel

[56] DOC IR No. 20 included in DOC Attachment 8.

Gas discuss the removal cost inclusion in the GUIC Rider and explain for each year how the *Accumulated Book Depreciation Reserve* removal cost amount translates to the *Accumulated Deferred Taxes* amount reported in this discovery response. This information is necessary for the Department to complete its analysis.

J. TIMP – PROGRAMMATIC REPLACEMENT AND MAOP REMEDIATION

Federal pipeline safety law on the transportation of natural and other gas, 49 CFR 192.619, effective since 1970, prohibits persons from operating segments of steel or plastic pipelines at a pressure that exceeds its maximum allowable operating pressure (MAOP). This same law prescribes how a pipeline's MAOP may be determined. Natural gas pipeline operators must be able to substantiate that its pipeline operating pressures are safe. Also, effective since 1970, federal laws 49 CFR 192.517 and 192.603 require that all records regarding MAOP determination must be kept for the useful life of the pipeline.[57]

The National Transportation Safety Board's investigation of the San Bruno, CA explosion found that the operator lacked accurate records to substantiate operating pressure levels,[58] and as result, on May 7, 2012, PHMSA issued an Advisory Bulletin to remind operators of gas and hazardous liquid pipeline facilities to verify their records relating to operating specifications for MAOP required by 49 CFR 192.517, as well as inform gas operators what PHMSA considers to be adequate records.[59] According to the PHMSA Advisory Bulletin, records must be traceable, verifiable and complete; that is, (1) traceable (those that can be clearly linked to original information about a pipeline segment or facility), (2) verifiable (those for which information is confirmed by other complementary, but separate, documentation) and (3) complete (those for which the record is finalized as evidenced by a signature, date or other appropriate marking).

Footnoted within Xcel's description of the TIMP project, *Programmatic Replacements and Maximum Allowable Operating Pressure (MAOP) Remediation*, Xcel quantified that 21 percent of its transmission pipeline lacked traceable, verifiable, and complete MAOP records[60]. The Department believes that Xcel conducted this self-audit in response to the recent 2012 law change that directed the U.S. Department of Transportation to require pipeline operators to verify their MAOP records and to report findings to the PHMSA.[61] Xcel's MAOP Project initiative focuses on remediating these data gap findings in order to ensure that the pipeline's MAOP can be supported by records that are traceable, verifiable, and complete.

---

[57] DOC Attachment 9, p. 3 (MAOP 192.619 letter from PHMSA).
[58] https://www.ntsb.gov/safety/safety-recs/recletters/P-10-001.pdf
[59] https://www.govinfo.gov/content/pkg/FR-2012-05-07/pdf/2012-10866.pdf
[60] Docket No. G002/M-17-787, Xcel Reply Comments (July 27, 2018), p. 8, footnote 9.
[61] Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, Section 23.
https://www.congress.gov/112/plaws/publ90/PLAW-112publ90.pdf

The Department understands that MAOP record retention and substantiation has been a requirement of pipeline operators since 1970[62]; therefore, because these requirements have been in place since 1970, it would seem that unless the Company has not conducted tests on its pre-1970 installed pipelines, the Company should have the supporting records.

The Department concluded that inadequate data records is concerning, especially given that data records were and continue to be within the control and responsibility of Xcel Gas's management. Having substantiated, objective MAOP records is fundamental to safe pipeline operations, protecting not only the liability of the utility and its operators, but the safety of those located near the pipeline infrastructure. To suggest that, prior to PHMSA's recent 2012 Advisory Bulletin, the pipeline records used to determine MAOP levels were not required to be supportable or complete is not reasonable. Xcel should be held accountable for its responsibility to substantiate by objective data records that its pipelines are operated within safe operating pressures.

The Department concludes that Xcel should not be afforded the opportunity to earn a profit for doing less than the 1970 law required; to do so otherwise would not be in the public interest. Therefore, the Department recommends that the Commission limit the "return on" any approved recovery of MAOP remediation capital costs to no more than the Company's weighted debt cost rate over the life of these capital expenditures. This recommendation is reasonable because it allows Xcel Gas to recover the expenditures made to comply with MAOP substantiation requirements; although ratepayers will still restore to Xcel the cost outlays[63] made to rectify data gaps, this action will not enrich the Company for lacking in its responsibility to retain and keep system records in order.

K. INTERNAL CAPITALIZED COSTS

In 2018 GUIC Rider Response Comments, the Department recommended that the Commission require Xcel to remove internal capitalized costs of "Overhead," "Transportation," and "Other," totaling $6,268,396, from the GUIC Rider.[64] This recommendation was based on the conclusion

---

[62] PHMSA has required since 1970 (49 CFR sections 192.517 and 192.603) that operators retain, for the useful life of the pipeline, records regarding the pipeline MAOP determination.

[63] In Attachment C, page 4, Xcel estimates its 2019 capital expenditures for this TIMP Project to be $26.36 million. Attachment C1 to the Petition reports prior years' 2017 and 2018 capital expenditures amounted to $5.8 million and $7.4 million, respectively. Attachment C1(c) reports estimated future expenditures of $32.4 million in 2020.

[64] This recommendation came out of the Department's jurisdictional review of the Company's invoices and work orders. From that review, the Department concluded that $8,276,882 million in internal capitalized costs could not be traced back to a particular contract. These costs were labeled: Overheads, Cost in Aid of Construction (CIAC), Materials, Other, Transportation, Company Labor Loadings, Company OT Labor, and Company ST Labor. The Department concluded in its Initial Comments: "Ultimately, the Department was unable to verify that these costs

that the Company was already paying a representative amount of these costs through base rates. The Department included a discussion of internal capitalized costs in those Response Comments, which the Department reiterates here for ease of reference.

1. Denial of Internal Capitalized Costs Outside of Rate Cases

The Commission has generally not allowed recovery of internal capitalized costs outside of rate cases, to avoid double-recovery of costs.[65] As the Commission explained in its Order for Xcel's 2012 Transmission Cost Recover (TCR) Rider:

> When Xcel employees are involved in the construction of new facilities, the Company treats their salaries as a capital cost rather than an operation and maintenance (O&M) expense. Xcel included approximately $1.5 million of capitalized internal labor costs for recovery in its proposed 2012 TCR rider.
>
> The Department recommends that the Commission exclude these costs from rider recovery because representative amounts are

---

were actually specific to work performed in Minnesota, or even truly incremental to costs already recovered in base rates." Docket No. G002/M-17-787, Department Initial Comments, p. 31.

[65] For example, the Commission denied recovery of internal costs in a rider outside of a rate case in:

- 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 determined in Otter Tail's then-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 Treatment for Costs Incurred After January 1, 2010; specifically the Commission decided not to determine cost recovery in the rider, sending those issues to Xcel's then-pending rate case , Docket, No. E002/GR-10-971.
- Docket No. E015/M-10-799. In the Matter of Minnesota Power's Petition for Approval of its Transmission Cost Recovery Rider; the Commission's May 11, 2011 Order required Minnesota Power to exclude internal costs from the rider.
- Docket No. E015/M-11-695. In the Matter of Minnesota Power's Petition for Approval of its 2011 Transmission Cost Recovery Rider Factor; the Commission's May 11, 2011 Order required Minnesota Power to exclude internal costs from the rider. The Commission's November 12, 2013 Order required Minnesota Power to "continue to exclude internal capitalized costs" from riders.
- Docket No. E002/M-12-50. In the Matter of Xcel Energy's Petition for Approval of 2012 Transmission Cost Recovery (TCR), Project Eligibility, TCR Rate Factors, and 2011 True-up; the Commission's February 7, 2014 Order required Xcel to removed capitalized costs from the rider.
- Docket No. E017/M-13-103. In the Matter of Otter Tail Power Company's Request for Approval of a Transmission Cost Recovery Rider Including the Proposed Transmission Factor for the Recovery Period from May 2, 2013 to April 30, 2014; the Commission's March 10, 2014 Order required Otter Tail Power to exclude internal costs.

> already being recovered from ratepayers through base rates. Xcel argues that none of the capitalized costs being requested for recovery in the 2012 rider were recovered in the base rates established in the Company's 2011 rate case. The Department agrees that the *specific* costs of projects completed after 2011 were not included in the 2011 test year but maintains that a representative amount of capitalized internal labor costs were included in 2012 base rates.
>
> Xcel has not shown that capitalized labor costs are not being recovered through base rates. [66]

In other words, a primary concern is that a utility could expense its employee internal labor in a rate case, then later capitalize that same labor in a rider, thus charging ratepayers for those same internal labor costs twice. In base rates, the utility would earn a return *of* this labor as an operating expenses; in the rider, the utility would earn both a return *of* this labor as a depreciation expense and a return *on* this rider through a return on rate base. Thus, the Commission correctly disallowed double-recovery of those costs in the TCR Rider.

In the Order for Otter Tail's TCR Rider, the Commission twice made the argument that *any* rider proceeding is an inappropriate place for approving capitalized internal labor costs:

> And the Department is also correct that this docket, like any rider update docket, is not an appropriate vehicle for making the exacting factual distinctions necessary to identify any internal labor costs not already included in base rates.[67]
>
> Nor does this, or any other rider proceeding, provide the comprehensive evidentiary development required to permit the Commission to make the factual determinations required to classify individual labor-cost accounts as subject to capitalization or expensing.[68]

---

[66] Docket No. E002/M-12-50, Commission's February 7, 2014 *Order Approving 2012 TCR Project Eligibility and Rider, Capping Costs, and Modifying 2011 Tracker Report*, page 5. Footnotes omitted.
[67] Docket No. E017/M-13-103. In the Matter of Otter Tail Power Company's Request for Approval of a Transmission Cost Recovery Rider Including the Proposed Transmission Factor for the Recovery Period from May 2, 2013 to April 30, 2014. Commission Order dated March 10, 2014, Page 6.
[68] Docket No. E017/M-13-103. In the Matter of Otter Tail Power Company's Request for Approval of a Transmission Cost Recovery Rider Including the Proposed Transmission Factor for the Recovery Period from May 2, 2013 to April 30, 2014. Commission Order dated March 10, 2014, Page 6.

Therefore, the Department continues to conclude that it is inappropriate for Xcel to recover internal capitalized costs outside of a rate case.

2. *Internal Capitalized Costs in the Current Docket*

In the 2018 GUIC Filing, the Company provided the Department with 2017 actual internal capitalized costs recovered through the 2017 GUIC Rider. In the current Petition, the Department requested that Xcel identify 2018 actual internal capitalized costs proposed for recovery though the 2019 GUIC Rider.[69] The Department summarizes Xcel's totals here:

Outside Contractor	$35,468,285
Overheads	$7,944,554
Cost In Aid of Construction (CIAC)	$(200)
Materials	$2,645,053
Other	$201,895
Transportation	$11,246
Salvage	$(2,702)
Company Labor Loadings	$122,616
Company OT Labor	$97,887
Company ST Labor	$313,448
Employee Expenses	$1,531
Subtotal Total Capital Costs	$46,803,614
Less Internal Labor	$(535,483)
Less RWIP	$(753,486)
Less Betterment Adjustment	$(2,039,682)
Total GUIC Recoverable Costs	$43,474,963

The Company appropriately backs out costs labeled as "Internal Labor." However, the Department notes that there appear to be additional internal labor costs that simply don't have the label of "labor." Specifically, when asked to describe Overhead costs during the 2018 GUIC Rider proceeding, the Company stated:

> Overhead costs include engineering, supervision, general office, and administrative costs that are incurred to ensure the continued proper operation of construction projects, but are costs that cannot be directly assigned to specific projects.[70]

[69] DOC IR No. 21, included in DOC Attachment 10.
[70] Docket No. G002/M-17-787. Xcel Energy's October 1, 2018 Response to Department IR No. 65, Page 1.

The Company's description of Overhead costs indicates that there is not a meaningful difference between Overhead and Labor costs. In other words, it seems that the costs of both Labor and Overhead are primarily used to pay for employee work. As such, the Overhead costs in Xcel's proposal have the same effect of inclusion of Labor costs in the dockets discussed above: it is possible that the cost of Xcel's internal employees may have been expensed during the rate case, then capitalized as Overhead GUIC costs. Without a full picture of the Company's finances, it is impossible for the Department to determine that such double-recovery of costs is not occurring.

Thus, the Department concludes that "Overhead" capital costs should not be recovered through the GUIC Rider. Similarly, Xcel hasn't shown that the miscellaneous costs under the category of "Other" are incremental to the costs being recovered in base rates. In addition, "Transportation" costs appear to be duplicative of amounts reflected in base rates. The Department does not take issue with the inclusion of CIAC, Materials, or Salvage at this time. Therefore, the Department recommends that the Commission deny the Company recovery of $8,157,695 in actual 2018 GUIC internal capital costs in the 2019 GUIC rider.

L. RISK ASSESSMENT AND PERFORMANCE METRICS

In the Company's instant filing, the risk assessment tool is applied to projected 2019 projects, whereas the performance metrics tool is applied to actual 2017 projects. These reports can be found in the following locations in the Company's Petition:

- TIMP 2019 Risk Assessment: Attachment C2
- DIMP 2019 Risk Assessment: Attachments D2(a) and D2(b)
- TIMP and DIMP 2017 Performance Metrics: Attachment W

1. Purpose and Process of Risk Assessment, Performance Evaluation, and Project Recovery

The prospective risk assessment tool and the retrospective performance metrics tool serve different purposes for the Company and the Commission.

For the Company, the purpose of the prospective risk assessment tool is to determine which projects should be prioritized in a given year, given economic constraints. The retrospective performance metrics tool was created pursuant to Commission Order;[71] the Company does not appear to use performance metrics for any internal purposes.

For the Commission, however, the purpose of these tools is to aid in determining the reasonableness of GUIC investments. Since risk assessment is prospective, this tool can be used to help the Commission set reasonable rates for specific projects that are expected to be undertaken in the upcoming year. Since performance metrics are retrospective, this tool can help the Commission determine how reasonable Xcel Gas's cost estimates were after 2017 projects are completed.

The Company's 2017 GUIC Rider was forward-looking, and the Company proposed a forward-looking 2019 GUIC Rider; thus, the Company has already recovered 2017 actual costs included in the performance metrics tool, but has not yet recovered 2019 projected costs included in the risk assessment tool. If the Commission determines that Xcel Gas has not demonstrated the reasonableness of charging ratepayers for projected expenditures, the Commission would not permit the Company to include those costs in the 2019 GUIC Rider. Also included in the 2019 GUIC Petition are the performance metrics tool to evaluate projects completed during the 2017 year. If the Commission were to determine that any of these actual 2017 expenditures were not reasonably incurred, the Commission would direct the Company to issue a refund through the 2019 GUIC Rider.

2. Risk Assessment Reporting

The Department reviewed the Company's 2019 GUIC risk assessment reporting, and concludes that the Company's risk assessment process appears to be reasonable. The Department summarizes the 2019 GUIC programs and variables considered when assessing risk.

---

[71] Docket No. G002/M-15-808, Commission *Order* dated August 18, 2016.

Table 7. Xcel Gas's 2019 GUIC Programs and Risk Assessment Inputs[72]

	Program	Variables Considered in Assessing Risk
TIMP	Transmission Pipeline Assessments – Replacement	Threats to Assets Present (External Corrosion, Internal Corrosion, Stress Corrosion Cracking or other crack like defects, Manufacturing, Welding/Fabrication/Construction, Equipment, Third Party Damage, Weather/Outside Force, Other) Population Density
	Transmission Pipeline Assessments – Integrity Assets	Years since last integrity assessment Presence of High Consequence Area on the line
	Transmission Pipeline ASV/RCV Installation	Travel time from nearest service center to valve location High Consequence Area downstream Population Density Likelihood of Failure
	Programmatic Replacement/MAOP Remediation	Legacy pipe Modern pipe Test pressure Material Records Location Presence of High Consequence Area or Moderate Consequence Area Grandfathered Pipeline
DIMP	Problematic Steel Mains and Services[73]	Leak date, class, cause Pipe length, material, pressure, diameter, coating Year installed Cathodic Protection Presence of Excess Flow Valve on Service Building Class Proximity to Pipeline Population Density

[72] Petition, Attachments C2, D2(a), D2(b).
[73] The Problematic Mains and Services Replacement Programs are separate, but in risk assessment are grouped together and instead evaluated based on steel versus plastic materials.

	Problematic Plastic Mains and Services	Material Type Year Installed Pressure System Population density
	IP Line Assessments	Mechanical Joints Present MAOP in acceptable range Record of Pressure Test acceptably complete History and presence of corrosion leaking and pitting Presence of 3rd-Party Damage History of Leakage due to other causes Population density Time of last assessment
	Distribution Valve Replacement	Operability of Valve Vault Condition Presence of Atmospheric Corrosion Number of premises in area if valve failure (population proxy)
	Sewer Gas Line Conflict	Area with Prior Conflict Area with a lot of rock, high water table Terraced properties Year of service installation Trenchless or unknown method of service installation Area previously inspected PE service off of joint main trench, steel main Known septic areas
	Federal Code Mitigation	Near/not near Vehicular Travel with/without Guard Post Protection Location (Residential Rural, Residential Urban, Commercial, Regulator Station Rural, Regulator Station Urban) Number of stories roofline above meter with/without ice shield protection Riser in concrete with no sleeve, installation date Building Use (Residential Single Family, Residential Multi-Family, Commercial) Riser Damage Riser Inactive Meter Accessibility

The Department appreciates the information provided by the Company, but notes that it is difficult to review for the Commission's purposes; that is, it is difficult to review for reasonableness. To that end, the Department provides the following discussions of ways that the Company can improve its risk assessment reporting.

a. Improving Risk Assessment Reporting

The Department notes that while Xcel provides risk information about the selected 2019 TIMP and DIMP projects, it does not include any risk information about non-selected projects. Without the context of all potential projects within a given program, the Commission cannot adequately get a sense of how reasonable the selected investments are. For example, the Company proposes to pursue the following 2019 Transmission Pipeline Assessment- Integrity Assets projects:

Table 8. Xcel's Gas's Proposed 2019 GUIC Projects for TIMP Transmission Pipeline Assessment- Integrity Assets Program[74]

Project	Project Location (Service Area)	Pipe Diameter	Pipe Vintage	Years Since Last Assessment	HCA	Risk Score	Risk Level (High, Medium, Low)
Crossover 16"	Rice Street	16	1964	6	Yes	4	High
Crossover 12"	Rice Street	16	1948	6	Yes	4	High
Highbridge Line	Rice Street	20	1952	6	Yes	4	High
Montreal Line North	Rice Street	20/24	1962	7	Yes	4	High

The Company shows the risk scores and risk levels for each of these projects, and also provides information about how this information is determined. However, the Company does not show any information about the rest of the system. As a result, it is not clear to the Department how many other potential TIMP Assessment- Integrity Asset projects exist, what their risk categories are, how quickly projects are being addressed versus how quickly they are becoming higher risk, whether the Company is appropriately prioritizing projects, and whether the Company is consistently apply risk rankings to all potential projects year to year. All of this information is critical for the Commission to determine if the proposed investments are the best use of ratepayer resources.

However, the Department notes that the risk assessment for the DIMP Poor Performing Mains and Services program provides some useful information. On Page 3 of Attachment D2(a), the Company provides a risk "profile" for all potential DIMP steel mains and services on its system.

74 Petition, Attachment C2, p. 9.

The Department noted inconsistencies in the risk composition, and so the Company provided corrected versions of this profile for years 2016-2018.[75] The Department provides this information below.

Table 9. 2016 Gas Distribution System Risk Composition (Total Potential DIMP Mains and Services Projects, Steel)

Risk Category	Project Risk Scores Range	Number of Optimain Projects Identified as of December 2016	Percentage
High	Score ≥ 36	2,829	4.68%
Medium	24 ≤ Score < 36	654	1.08%
Low	1 ≤ Score < 24	12,600	20.86%
None	Score < 1	44,320	73.37%
Total	**All**	**60,403**	

Table 10. 2017 Gas Distribution System Risk Composition (Total Potential DIMP Mains and Services Projects, Steel)

Risk Category	Project Risk Scores Range	Number of Optimain Projects Identified as of December 2017	Percentage
High	Score ≥ 36	2,693	4.48%
Medium	24 ≤ Score < 36	665	1.11%
Low	1 ≤ Score < 24	12,547	20.89%
None	Score < 1	44,152	73.52%
Total	**All**	**60,057**	

[75] DOC IR No. 50 included in DOC Attachment 11.

Table 11. 2018 Gas Distribution System Risk Composition (Total Potential DIMP Mains and Services Projects, Steel)

Risk Category	Project Risk Scores Range	Number of Optimain Projects Identified as of October 2018	Percentage
High	Score $\geq$ 36	1,415	2.42%
Medium	24 $\leq$ Score < 36	663	1.13%
Low	1 $\leq$ Score < 24	12,519	21.37%
None	Score < 1	43,990	75.08%
Total	**All**	**58,587**	

These types of high-level snapshots provide useful information. For example, the above tables indicate that the number and percentage of high risk projects has decreased over time. This trend indicates that the Company does appear to be appropriately prioritizing projects.

However, as the Department notes, the Company only provides this information for the DIMP Poor Performing Mains and Services- Steel project. In Department IR 50, the Department asked the Company to provide such profiles for each TIMP and DIMP program. The Company stated the Poor Performing Mains and Services program uses specific software that develops this type of project risk profile, but that other programs do not use this software. Thus, the Company stated that is was unable to create this type of risk profile for all potential projects in each TIMP and DIMP program.[76]

The Department finds this response unacceptable, given that ratepayers are being charged for costs of TIMP work. It should not matter which software or methodology is used to identify and prioritize projects; the Company should still be able to identify and rank by all potential projects within a given program. Therefore, the Department recommends that the Commission direct the Company to develop risk profiles, such as those shown in Tables 9-11 above, for all potential projects in each proposed TIMP and DIMP program. Further, the Department recommends that Xcel continue to work to improve its risk assessment reporting in future filings, with the goal of providing better explanations of the Company's assets.

b. Inconsistencies in the 2019 Risk Assessment Filing

The Department found additional issues with the risk assessment portion of the Company's filing. First, the Company did not appear to include the Eagan Line from the Transmission

[76] DOC IR No. 50 included in DOC Attachment 11.

Pipeline Assessment – Replacement program in its risk assessment submitted for 2019,[77] even though this project was included in the project detail portion of the filing.[78]

Further, the Company included a table of high and medium risk DIMP Distribution Valve Replacement projects in the DIMP risk assessment,[79] but does not appear to include any proposed Distribution Valve Replacement projects in its filing. The Department requests that the Company clarify and correct these inconsistencies in Reply Comments.

The Department also compared the proposed 2019 DIMP main and service replacements against those proposed in 2018. The Department found significant overlap between the two filings, but also found cost inconsistencies. The Department details this information in the following table.

Table 12. Proposed Overlapping 2018 and 2019 DIMP Poor Performing Mains and Services Projects[80]

City	Description	2018 GUIC Filing			2019 GUIC Filing		
		Total Design Ft.	Total Services	Anticipated Cost	Total Design Ft.	Total Services	Anticipated Cost
Cottage Grove	Pt Douglas Rd, Ideal Ave	4,735	40	$221,495	7,000	40	$394,463
	Hyde Ave	3,710	41	$184,247	3,600	41	$234,268
Lake Elmo	31st/Jamley/Janero	6880	43	$241,955	6882	43	$330,449
Mendota Heights	Bachelor-Stanwich	10,570	100	$506,307	10,570	100	$551,100
	Overlook Rd	5,700	45	$263,144	5,700	45	$285,735
Red Wing	9th St	850	8	$40,699	850	8	$44,264
	Woodland Dr	4,200	48	$210,377	4,200	48	$229,584
	Reding Ave	4,830	48	$233,912	4,830	48	$254,784
	Maple St	7,600	161	$477,146	7,600	174	$527,242
Roseville	Oxford	1,200	5	$50,443	1,200	5	$54,415
Winona	E 10th St	3,000	108	$231,900	3,000	108	$258,564
	E 7th St	3,500	64	$201,868	3,500	64	$222,112

[77] Petition, Attachment C2, p. 2.
[78] Petition, Attachment C, p. 7.
[79] Petition, Attachment D2(a), p. 11.
[80] Docket No. G002/17-787, Xcel Petition, Attachment D1(d) and Docket No. G002/18-692, Xcel Petition, Attachment D1(a) p. 1.

	E 9th St	1,400	35	$91,160	1,400	35	$100,905
	Collegeview St	2,000	54	$1,346,660	2,000	54	$149,282
	W 9th St	3,400	64	$198,126	3,400	64	$218,112
	7th St W	5,800	138	$369,910	5,800	138	$409,054
	Conrad Dr	6,600	133	$394,307	5,300	133	$382,639

Each of the above projects was included in both the 2018 and 2019 GUIC filings. Costs of projects that were already included in 2018 should not be included in the 2019 GUIC, as including the same project in 2019 would result in double-recovery of the same project.

The Company did not identify this proposed double-recovery in its Petition, let alone explain why the costs were included again. The Department sent discovery to Xcel to allow the Company to explain this issue. Xcel addressed the inclusion of some of these projects during discovery, but the remainder have yet to be resolved. Thus the Department recommends that proposed 2019 costs for all projects listed in Table 12 be removed from the 2019 GUIC Rider.

Finally, there appears to be some notable cost discrepancies in projects that appear to be identical. For each project (save the Winona Collegeview St. and Conrad Dr. projects), the costs increased from 2018 to 2019. The costs of the Winona Collegeview project decreased, but the amount identified for the 2018 GUIC is so much greater than the costs of any other project ($673.33/foot) that it appears that the 2018 cost estimate was a data error (i.e. should have been $134,666). Again, the Company does not explain these discrepancies.

The Department recommends that the Commission disallow cost recovery in the 2019 GUIC of the projects listed above in Table 12, as Xcel has not shown that the costs of these projects should be recovered from ratepayers in the 2019 GUIC. These projects total $4,646,972 in proposed 2019 costs.

In addition, the Department requests that in Reply Comments, the Company identify the costs for the Winona Collegeview project, proposed to be recovered in both the 2018 and 2019 GUIC riders. If the amount for this project for 2018 was $1,346,660, Xcel should also fully explain why the costs of this project are so much higher than costs of other projects.

3. Performance Metrics Reporting

The Performance Metrics tool is used after the projects have already been completed. Xcel evaluates its programs with five performance metrics, as shown in the following table.

Table 13. Xcel's GUIC Performance Metrics[81]

Program	Metric	Benefit
DIMP	Leak Rate by Vintage and Pipe Type	Monitor the impact of renewal efforts on the leakage rates. Selection of higher-risk pipe segments will lower leakage rates over time.
	Poor Performing Main Replacements Unit Cost	Monitor unit costs greater than one standard deviation above the mean to ensure variances are understood and reasonable.
	Poor Performing Service Replacements Unit Cost	Monitor unit costs greater than one standard deviation above the mean to ensure variances are understood and reasonable.
TIMP	Gas Transmission Anomalies Repaired	Monitor the impact of pipeline assessment, repair and renewal efforts on the number of anomalies that require repair. Appropriate repairs and renewal efforts will lower anomalies over time.
	Actual vs. Estimated Cost Variance Explanations for Capital Projects	Monitor cost variances to ensure variances are understood and reasonable.

The Department reviewed the performance metric information included in the Company's filing, and concluded that, while the Company has met its compliance obligation of the Commission's Order,[82] there is room for improving the reporting of performance metrics. The following discussion outlines ways in which Xcel's performance metrics reporting tool can be improved.

a. Cost and Effectiveness Performance Metrics for Each TIMP and DIMP Program

As outlined in Section L.1 above, the purpose of performance metrics is to help the Commission make a retrospective determination as to whether the Company reasonably pursued GUIC investments. From the Department's perspective, the bare minimum of evaluating the reasonableness of these costs should involve evaluating the cost and effectiveness of each program. If these two metrics are captured each year, the Commission may then construct a better sense of the cost effectiveness of each TIMP and DIMP program.

---

[81] Petition, Attachment W, Table 3.
[82] Docket No. G002/M-15-808, Commission *Order* dated August 18, 2016 and Docket No. G002/M-16-891, Commission *Order* dated February 8, 2018.

However, Xcel's five current performance metrics do not adequately measure cost and effectiveness for each GUIC program, if at all. The below table shows Xcel's current performance metrics based on the Department's perception of which TIMP and DIMP programs those metrics are meant to evaluate.

Table 14. Current Xcel Performance Metrics by 2017 GUIC Program and Type of Metric

	Program	Cost Performance Metric	Effectiveness Performance Metric
TIMP	East Metro	Actual versus estimated cost variance explanation for capital projects	
	Transmission Pipeline Assessments	Actual versus estimated cost variance explanation for capital projects	Gas Transmission Anomalies Repaired
	ASVs and RCVs	Actual versus estimated cost variance explanation for capital projects	
	Programmatic Replacement and MAOP Remediation	Actual versus estimated cost variance explanation for capital projects	
DIMP	Poor Performing Main Replacement	Poor Performing Main Replacement Unit Cost	Leak rate by vintage and pipe type
	Poor Performing Service Replacement	Poor Performing Service Replacement Unit Cost	Leak rate by vintage and pipe type
	Intermediate Pressure (IP) Line Assessments		Leak rate by vintage and pipe type
	Distribution Valve Replacement		
	Sewer and Gas Line Conflict Investigation		
	Federal Code Mitigation		

As shown in the above table, Xcel's existing performance metrics do not appear to cover each of the Company's 2017 GUIC programs. Moreover, a single metric is frequently used to measure multiple programs. For example, the metric "Leak rate by vintage and pipe type" appears to be the effectiveness performance metric for three different DIMP programs: Poor Performing Main Replacements, Poor Performing Service Replacements, and IP Line Assessments. To clarify, the Company does not submit different leak rate metrics for mains, services, and IP line; the Company submits a single metric, which appears to cover all three DIMP programs. The Department discusses each of the current metrics further below, but notes here that the existing metric is too broad to meaningfully evaluate three different programs at once.

Further, Xcel's accountability for costs is inadequate. Given that a rider allows a utility to recover costs year to year without the cost discipline of a rate case, cost accountability is a critical aspect of the rider.

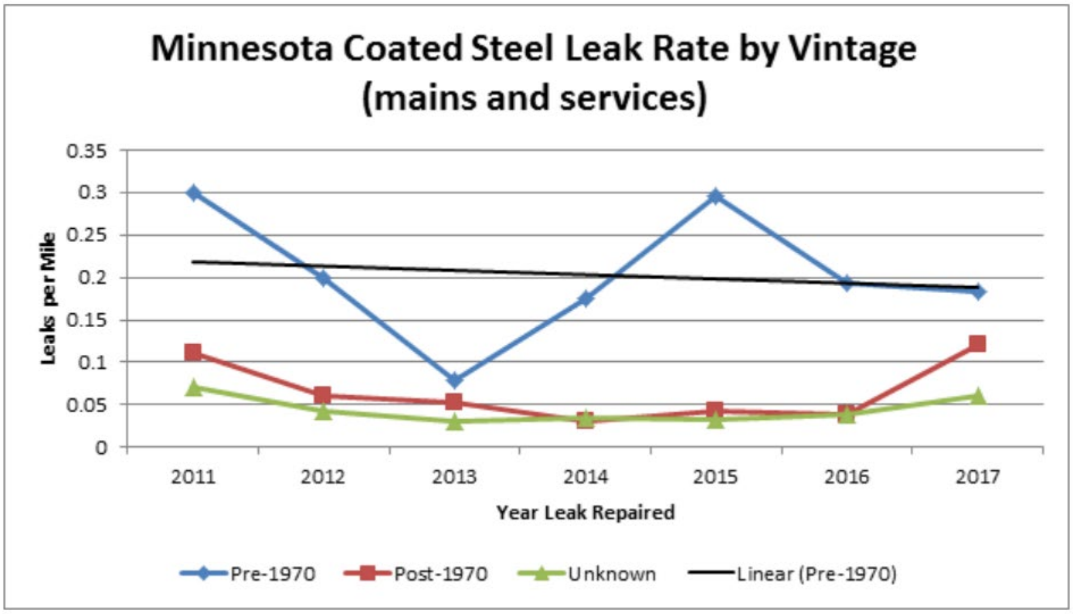
The Department recommends, at a minimum, that for each GUIC TIMP and DIMP program reviewed, the Commission should require the Company submit *at least* one cost performance metric *and* one effectiveness performance metric. Furthermore, the metrics should be specific enough to give the Commission meaningful information about the specific program being evaluated. To that end, the Department provides the following discussion about potential ways to improve each of the existing metrics, followed by a discussion of additional metrics that could be introduced to help the Commission better determine reasonableness of investments in each program.

Finally, consistent with the cost discipline used for other riders, Xcel should not be allowed to recover via the rider any cost overruns; instead, the Company should be allowed to recover such costs only in Xcel Gas's next rate case, and only if the Company demonstrates that it is reasonable to charge ratepayers for such cost overruns. The Department asks that in Reply Comments, the Company submit a table identifying all 2017 cost overruns for all 2017 GUIC programs, and identify and where these overruns may have been included for recovery through either the 2018 and 2019 GUIC Riders.

b. Leak Rate By Vintage and Pipe Type (DIMP Metric)

The Company submitted the following chart showing number of leaks per mile for coated steel distribution mains and services:

Figure 2. Xcel Leak Rate By Vintage and Pipe Type Over Time (Submitted as DIMP Performance Metric for 2017 GUIC Projects)[83]



The Company specified that only underground leakage not associated with excavation damage was included to evaluate GUIC impact.

The Department agrees that measuring leak rate per mile is a good indicator of the effectiveness of GUIC performance. However, the Department notes that it is hard to use this metric to determine the reasonableness of different program costs within the GUIC Rider.

The Department recommends that leakage rates per mile be tailored more specifically to the types of investments that are being made, rather than to distribution mains and services as a whole. While it appears that the delineation between pre- and post-1970 (or unknown) is necessary, that categorization alone is too broad to provide meaningful information. Further, to identify the effectiveness of the project, Xcel should compare the metrics for replaced versus not replaced projects.

For example, it would be more helpful for Xcel to compare the number of leaks for all replaced steel mains versus all non-replaced steel mains (pre- and post-1970). In addition, Xcel should show the same information for replaced versus non replaced services, repaired versus non-repaired intermediate pressure lines, etc.

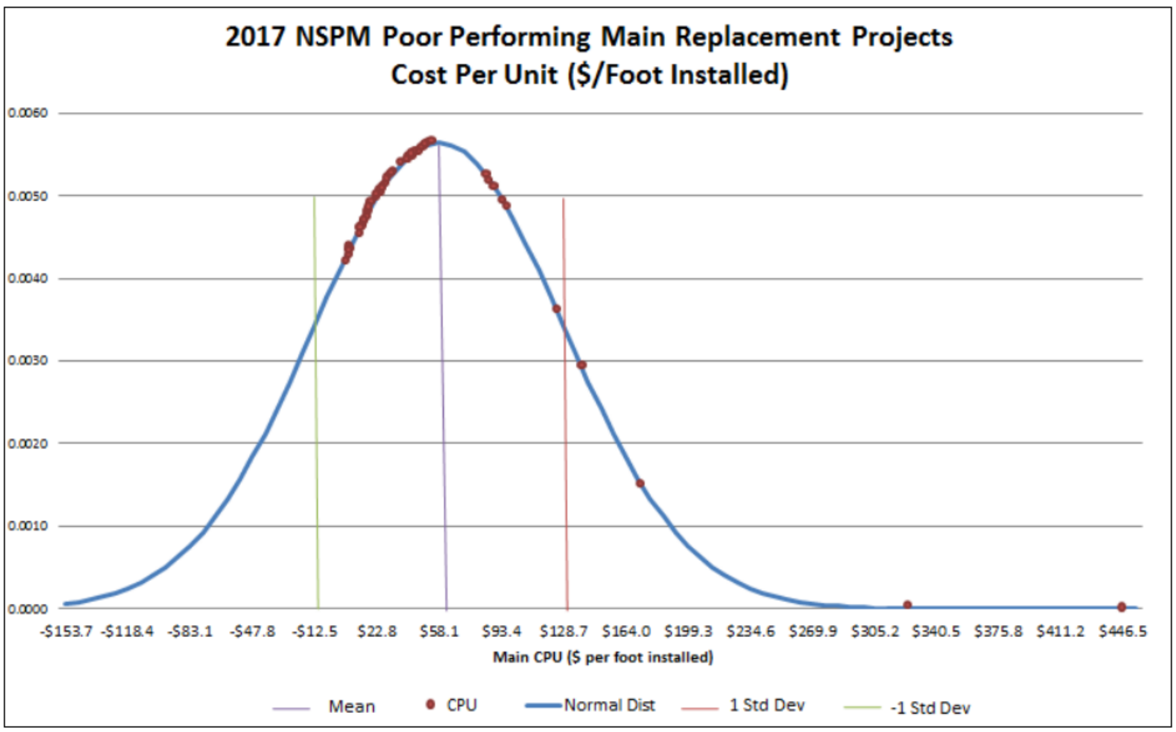
[83] Petition, Attachment W p. 6.

In addition to leaks/mile, Xcel should create a leak volume metric for each type of replaced or repaired asset. The Department provides specific leak-related effectiveness performance metrics for each program in Table 17 below.

c. Poor Performing Main Replacement Unit Cost (DIMP Metric)

The Company submitted the following curve for the poor performing main replacement unit cost:

Figure 3. Cost Per Foot of Poor Performing Main Replacement Projects (DIMP Performance Metric for 2017 GUIC)[84]



Xcel suggested the performance metric of cost per foot of poor performing main replacement projects in Docket 16-891. The Department agrees that this metric is useful for cost comparison. However, as noted in Table 14 above, this performance metric is only used for the DIMP Poor Performing Mains and Poor Performing Services programs. Instead, the Department notes that this same type of unit cost analysis would be useful if applied to costs in each type of program. The Department's suggested applications of this metric is listed in Table 17 below.

[84] Petition, Attachment W p. 7.

However, the Department also notes that there is room for improvement. For start, the Department notes that observations in the above figure are clustered primarily between the -1 Standard Deviation (SD) and the mean, with various other observations spread throughout the right hand side of the curve. This information suggests that the data is not normally distributed; if the data were normally distributed, the data points would instead be clustered more centrally around the mean. A more appropriate curve would look more like a slope rather than a hill, with right-sided tail. With an improved fit, it may be that more observations fall outside of the +1 SD cutoff. The Department requests that in Reply Comments, the Company explain its decision to use a normal distribution curve.

Further, the Department notes that there may be enough meaningful differences between projects to warrant meaningful cost differences, and so some projects may be inappropriate to compare to others. The Company acknowledged this observation at the September 26, 2018 meeting between the Department, the OAG, Xcel, and MNOPS. At that meeting, Xcel pointed out that the observations that fell outside of the standard deviations tended to be for highly developed areas, such as downtown St. Paul. Xcel stated that population density is one reason it can be difficult to compare different observations from a cost standpoint.

In the Company's report in Attachment W, Xcel stated that the observations falling above +1 SD were for the following projects:

- North St. Paul ($119.40/foot): project was for larger diameter (8") and longer distance steel main replacement (900 feet), involving more welders, tappers, and weld inspectors
- Winona ($146.74/foot): project was for urban area involving traffic control, restoration, contract inspection, and storm water pollution
- Winona ($175.13/foot): project involved boring under railroad
- Sartell ($440.04/foot): project involved boring Mississippi River, including use of boat to help track bore across river

The Department notes that the Company did not appear to address the observation that appears at around $320/foot. The Department was unable to find this observation in the Company's raw data submitted in response to IR No. 50; the Department asks that the Company clarify in Reply Comments what explains this observation.

At the September 26 meeting, the Department suggested that one way to make the data more meaningful might be to make different curves for each of the different consequence classes identified in the Company's risk assessment, which are based on population density. For example, Xcel provides the following consequence classes for poor performing plastic mains:

Table 15. DIMP Poor Performing Plastic Mains Consequence Classes based on Population Density[85]

Consequence			
1	1.25	1.5	1.75
Population Density from Census Block Data < 1000 people per square mile	1000 < Population Density from Census Block Data < 2000	Population Density from Census Block Data ≥ 2000	Business District

In Department IR No. 50, the Department asked the Company to classify each observation in the provided raw data by the appropriate 1-4 consequence class. The Company responded that mains and services are not categorized on a 1-4 scale, and so the Company could not fulfill the request. By "appropriate 1-4 consequence class," the Department meant for the Company to use whichever consequence class scale was appropriate to the dataset, with the understanding that there are four consequence classes. However, the Department can understand the confusion, and asks that the Company provide the Department with the raw data, with observations to be categorized by consequence class using the appropriate scale.

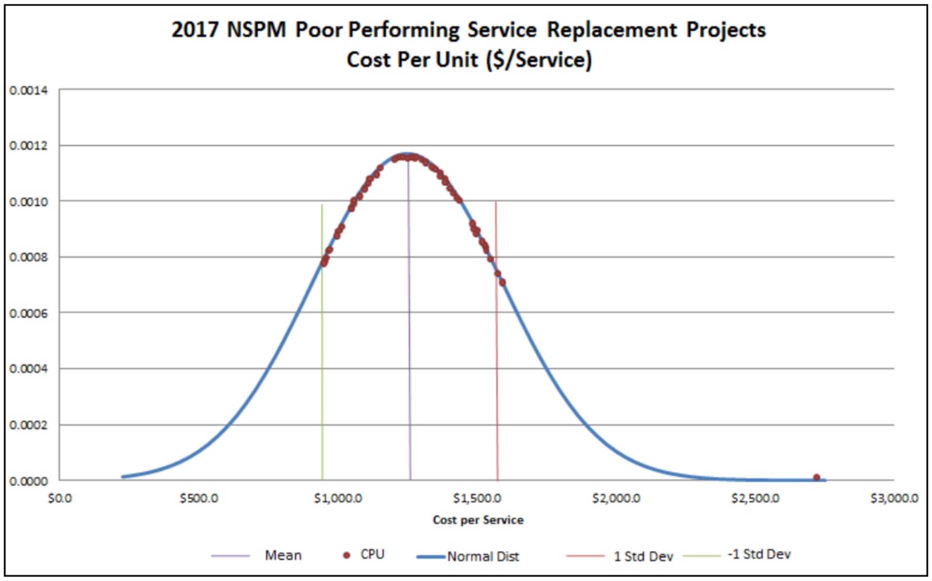
Finally, the Department notes that although the Department is interested in seeing the data separated out by consequence class, there may be other ways of segregating the data to allow for more meaningfully evaluations. For example, the Company may wish to create different curves for different materials, diameters, lengths, or abnormal crossings. The Department will continue to work with the Company on this matter.

d. Poor Performing Service Replacements Unit Cost (DIMP Metric)

The Company submitted the following curve for the poor performing service replacement unit cost:

[85] Attachment D2(a), page 5.

Figure 4. Cost Per Foot of Poor Performaing Main Replacement Projects (DIMP Performance Metric for 2017 GUIC)[86]



The Company specified that three observations fell above one standard deviation:

- North Oaks ($2,743/service): the service was three times longer than the average service
- St. Cloud ($1,640/service): the service was longer on average and required additional restoration costs
- Winona ($1,599/service): the service required excessive restoration costs and traffic control

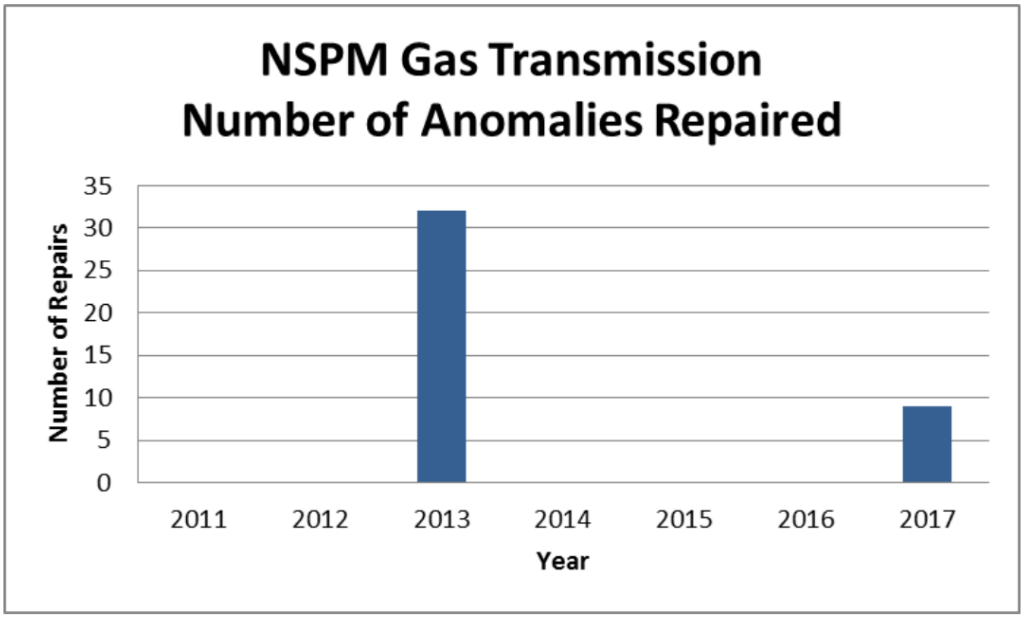
Again, the Department considers this method of cost comparison to be useful, and should be applied to other programs. The Department agrees that this data does appear to be normally distributed. However, the Department questions the Company's decision to use only a cost/service unit when a cost/foot unit may also provide meaningful information. Further, Department again notes that it may be worthwhile to have different curves for different population-based consequence classes. The Department will continue to work with the Company on these matters.

e. Gas Transmission Anomalies Repaired (TIMP Metric)

Xcel submitted the following figures:

[86] Petition, Attachment W p. 8.

Figure 5. Number of Gas Transmission Anomalies Repaired (TIMP GUIC 2017 Performance Metric)[87]



The Company appears to report that nine transmission anomalies were repaired in 2017. The Company further categorizes each of the anomalies by cause of disrepair.

The Department does not find this information to be useful as a performance metric, as it does not help the Commission determine whether costs were reasonably incurred. For this performance metric to be useful as a measure of effectiveness, the Company would need to report performance of repaired assets versus non-repaired assets. For this performance metric to be useful as a measure of cost, the Company should create a scatter plot distribution as done for the Poor Performing Mains and Services Figures above. While this distribution curve will likely need to be modified in some way to create meaningful data, the Department intends to work with the Company on this issue.

f. Actual vs. Estimated Cost Variance Explanations for Capital Projects (TIMP Metric)

The Company submitted the following for actual versus estimated cost variance for TIMP projects:

[87] Petition, Attachment W p. 10.

Table 16. Actual Versus Estimate Cost Variance for 2017 Capital Projects (TIMP 2017 GUIC Performance Metric)[88]

Project	Cost Estimate at Issue for Construction ($ Millions)	Actual Cost ($ Millions)	Variance Explanation
Montreal Line South Renewal, Replace 1,300' of 20" Grade B pipe installed in 1948 by Northern Natural Gas and sold to Northern States Power with 1,300' of new 20" Grade X-52 pipe. **Island Line South Renewal,** Replace 7,900' of 20" Grade B pipe installed in 1952 by Northern Natural Gas and sold to Northern States Power with 7,900' of new 20" Grade X-52 pipe.	$7.7M	$7.9M	Not significant.

The Department notes that projected versus actual costs for a program can produce a meaningful performance metric, but this metric does not appear to do so. Furthermore, this same information is already reported in the project detail portion of the filing. To evaluate variation in TIMP costs, the Department notes that more granular data is needed to produce more observations. The Company should granularize the data with the goal of creating a meaningful scatter plot distribution to better analyze the costs associated with capital projects.

Further, as discussed above, cost overruns should not be charged to ratepayers in a rider.

g. Potential New Metrics

The Department reviewed the purpose and risk assessment of each of Xcel's 2017 TIMP and DIMP programs to determine what metrics might be the most appropriate for measuring cost and effectiveness of each GUIC program.

The Department did not include the TIMP East Metro program in its review because that program ended in 2016; 2017 costs were simply residuals from 2016. Therefore, the Department concludes that it is not worth developing a metric for this program at this time. In similar future projects, however, the Commission may wish to ask the Company to compare cost and effectiveness metrics of GUIC work in the relevant geographical region (such as "East Metro") to the cost and effectiveness of other regions that did not experience GUIC work.

---

[88] Petition, Attachment W, p. 11.

The following table shows the Department's suggested updates to the performance metrics, based on the Department's suggestions for improvements to current metrics, as well as the Department's review of the goals of each program.

Table 17. Department's Suggested Performance Metrics by 2017 GUIC Program and Type of Metric

	Program	Cost Performance Metric	Effectiveness Performance Metric
TIMP	East Metro		
	Transmission Pipeline Assessments	-ILI Assessment Unit Cost -Anomaly Repair Unit Cost	-Number of leaks for repaired assets versus non-repaired assets -Volume of leaks for repaired assets versus non-repaired assets
	ASVs and RCVs	-ASV Unit Cost -RCV Unit Cost	- Time period of leak detection by event for each replaced asset versus non-replaced asset - Volume of leak for each leak by event for each replaced asset versus non-replaced asset
	Programmatic Replacement and MAOP Remediation	-Main Replacement Unit Cost (per foot)	-Percentage of records complete over time -Number and volume of leaks for replaced pipelines versus non-replaced comparable assets
DIMP	Poor Performing Main Replacement	-Poor Performing Main Replacement Unit Cost (per foot)	-Number and volume of leaks for distribution mains replaced versus non-replaced comparable assets

	Poor Performing Service Replacement	Poor Performing Service Replacement Unit Cost (per service and per foot)	-Number and volume of leaks for services replaced versus non-replaced comparable assets
	Intermediate Pressure (IP) Line Assessments	-Assessment Unit Cost -Anomaly Repair Unit Cost	-Number and volume of leaks for IP lines repaired versus non-repaired comparable assets
	Distribution Valve Replacement	-Replacement Unit Cost	- Time period of leak detection by event for each replaced asset versus non-replaced asset - Volume of leak for each leak by event for each replaced asset versus non-replaced asset
	Sewer and Gas Line Conflict Investigation	-Inspection Unit Cost -Repair Unit Cost	-Percentage of potential projects inspected over time
	Federal Code Mitigation	-Repair/project unit cost	-Percentage of projects out of compliance over time

The Department notes that the Company may be able to improve on the above suggestions. Therefore, the Department intends to review any suggested improvements to the above metrics in Xcel's Reply Comments.

The Department also recommends that the Commission direct the Company to develop at least one unique cost performance metric and one unique effectiveness performance metric for each TIMP and DIMP program in a given year.

V. DEPARTMENT CONCLUSIONS AND RECOMMENDATIONS

The Department requests that in Reply Comments, Xcel address the following:

- Clarify whether the Company assumed, or included, any other cost drivers in its data and projections in the sales forecast;
- Clarify if billing month customer count numbers are converted to calendar month average customer counts in the forecasting process;
- Revise the Petition Schedules G and H to break out the Accumulated Deferred Income Tax (ADIT) balance to separately identify the excess ADIT (i.e., EDIT) balance, due to the TCJA, that is to be returned to ratepayers and to also show the amortized amount of the EDIT being included in the GUIC revenue requirement;
- Discuss the EDIT amortization technique/method it will use in the GUIC Rider and whether the procedure is consistent with the technique/method applied to its base rates' EDIT amortization and refund to ratepayers. Also, if the amortization of the GUIC Rider EDIT has not yet begun, the Company should explain why and when the EDIT refunding will commence;
- Update affected revenue requirement schedules to discontinue ADIT proration where it is not required. The proposed rider rate effective date is post test period;
- Discuss the removal cost inclusion in the GUIC Rider and explain for each year (2017 – 2019) how the *Accumulated Book Depreciation Reserve* removal cost amount translates to the *Accumulated Deferred Taxes* amount reported;
- Submit a table identifying all 2017 cost overruns for all 2017 GUIC programs, and identify and where these overruns may have been included for recovery through either the 2018 and 2019 GUIC Riders;
- Clarify and correct inconsistencies between the program detail and program performance metrics parts of the filing;
- Clarify the cause of the ~$320/foot observation shown in Figure 3 above;
- Explain its decision to use a normal distribution curve in Figure 3 above;
- Provide the Department with a spreadsheet of the raw data behind Figures 3 and 4, with observations categorized by consequence class using the appropriate scale;
- Explain why the costs of the 2018 DIMP Winona Collegeview project shown in Table 12 above are so much higher than costs of other projects;
- Suggest ways to improve the Department's proposed cost and effectiveness performance metrics shown in Table 17 above.

The Department recommends that the Commission:

- Maintain the GUIC ROR and capital structure at the levels set for the 2017 GUIC Rider;
- Require Xcel to (1) reduce its 2019 GUIC Rider revenue requirement by $50,000 to account for the cost of sewer inspection work included in its current base rates, and continue such an adjustment in its prospective GUIC petitions corresponding to the amount included in base rates;

- Direct Xcel to remove the component "Annual Deferred Tax Impact" when determining the GUIC Plan Retirement Revenue Credit. This recommendation will decrease the overall 2019 GUIC Revenue Requirement by $0.02 million;
- Deny Xcel Gas's request to include a carrying charge on the GUIC tracker balance;
- Direct Xcel to exclude from its GUIC Rider recovery request the cost amount above what the GUIC project would have otherwise cost had the project been completed without replacement of the low-risk infrastructure.
- In its future GUIC filings for the applicable projects which include cost recovery of low-risk project work, direct the Company to report and fully explain the cost bids of the higher-risk required project work with and without replacement of low-risk infrastructure.
- Require the Company to retain and have available upon request verifiable supporting documents for the cost comparisons of "with and without" low-risk infrastructure replacement;
- For the TIMP project, *Programmatic Replacements and Maximum Allowable Operating Pressure (MAOP) Remediation*, limit the "return on" any approved recovery of MAOP remediation capital costs to no more than the Company's weighted debt cost rate over the life of these capital expenditures;
- Deny the Company's proposed recovery of $8,157,695 in actual 2018 GUIC internal capital costs for Overheads, Other, and Transportation, to the extent these costs are not removed elsewhere;
- Direct the Company to develop risk profiles, such as those shown in Tables 9-11 above, for all potential projects in each proposed TIMP and DIMP program, and submit these profiles in future filings;
- Disallow cost recovery in the 2019 GUIC of the DIMP projects that also appeared in the 2018 GUIC, listed Table 12 and totaling $4,646,972;
- Direct the Company to continue to work with the Department and other parties in improving its risk assessment and performance metrics reporting;
- Direct the Company to develop at least one unique cost performance metric and one unique effectiveness performance metric for each TIMP and DIMP program.

/jl

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

Xcel Energy Information Request No. 14
Docket No.: G002/M-18-692
Response To: MN Department of Commerce
Requestor: Dorothy Morrissey / Danielle Winner
Date Received: January 8, 2019

Question:

Topic: DIMP Project Status
Reference(s): Petition, pages 29, 31-32.

Please provide a project completion status update for the DIMP Distribution Valves and Pipeline Data project and the Federal Code Mitigation project.

Response:

Project	Project Completion Status
Pipeline Data Project	Completed in 2015.
Federal Code Mitigation Project	Completed in 2018.
DIMP Distribution Valves	Five of the 16 planned distribution valve replacements were completed in 2018. Two valves were removed from the program because they will be replaced as part of other projects. Two valves were delayed into 2019 due to city permitting issues. Two valves were delayed into 2019 due to material lead time issues. The remaining five valves were delayed into 2019 due to resource availability. We anticipate that the remaining identified valves will be replaced in 2019. We inspect emergency valves annually and may identify a need to add, replace, or otherwise rehabilitate existing distribution valves in the future.

Preparer: Ray Gardner
Title: Director
Department: Gas Integrity Management Programs
Telephone: 303-571-3904
Date: January 18, 2019

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

Xcel Energy		Information Request No. 40
Docket No.:	G002/M-18-692	
Response To:	MN Department of Commerce	
Requestor:	Dorothy Morrissey/ Danielle Winner	
Date Received:	January 25, 2019	

Question:

Topic: 2017 Tax Cuts and Jobs Act (TCJA) and Excess ADIT

A. Please identify the amount of the 2017 year-end Accumulated Deferred Income Tax (ADIT) balance in this rider that is the Excess ADIT (or EDIT) as a result of the recent change in federal income tax rate; and specify what amount of the EDIT is protected and what amount is unprotected.

B. Please explain whether or not the Company has included any amortization of excess deferred income tax (EDIT) in the GUIC rider revenue requirement, and/or has made adjustments to accumulated deferred income tax balances (ADIT) related to the TCJA; if not, explain why, if so, show where in the GUIC rider schedules any TCJA-related ADIT/EDIT adjustments/amortizations were included.

Response:

A. The Company's ADIT balances shown in the GUIC Rider petition schedules contain both current ADIT and excess ADIT (EDIT). The EDIT is not shown in those schedules as a separate number. The table below shows an estimate of the EDIT embedded in the revenue requirement calculations as of December 2017:

	Ending Balance Dec-17	
TIMP Accumulated Deferred Taxes (Attachment G)	$8,052,591	a
DIMP Accumulated Deferred Taxes (Attachment H)	6,423,723	b
GUIC Ending Balance: Accumulated Deferred Taxes	$14,476,315	c = a + b
State Composite Tax Rate in 2017	41.3700%	d
ADIT Balance divided by 2017 Composite Tax Rate	$34,992,300	e=c / d
State Composite Tax Rate in 2018	28.7420%	f
ADIT Balance multiplied by 2018 Composite Tax Rate	$10,057,487	g = e * f
Approximate Excess ADIT as of 12/31/2017	$4,418,828	h=c - g

The Company considers all of the EDIT as protected since it is related to plant assets.

B. The Company has included amortization of EDIT in the GUIC rider revenue requirement starting in 2018. The ADIT balances on petition schedules G and H contain both current ADIT and EDIT. The flow back of the EDIT to customers is dependent on the book lives of the specific assets, and begins when book depreciation for specific assets exceeds tax depreciation. For assets that were in-service but for which the ADIT has not yet begun unwinding prior to January 1, 2018, the effective date of the new federal tax rate, annual deferred tax expense will be calculated at the current rate, and the ADIT balance will continue increasing. When the ADIT balance for each vintage of assets stops increasing and starts decreasing, the annual deferred tax calculation will switch from using the current tax rate to using the average of the tax rates applied up to this point, which ensures that the vintage deferred record will unwind to zero over the remaining life for the vintage. This assures that the benefit of a tax rate change on the deferred tax balance is ratably shared with all customers receiving benefit from the asset over the remaining life of that asset. There is no separate amortization or adjustment for TCJA-related changes to ADIT balances. Any return of the EDIT faster than this method would be a violation of tax normalization rules.

Preparer: Mary Pope
Title: Senior Rate Analyst
Department: Revenue Requirements North
Telephone: 612-330-6574
Date: February 4, 2019

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

Xcel Energy		Information Request No. 41
Docket No.:	G002/M-18-692	
Response To:	MN Department of Commerce	
Requestor:	Dorothy Morrissey/ Danielle Winner	
Date Received:	January 25, 2019	

Question:

Topic: Response to DOC Information Request No. 7
Reference(s): Attachment A to Response

Please explain the four distinct sewer inspection program categories, *Legacy Project, Emergency, New Construction* and *Cleared by Maps;* and indicate which inspection activity categories' costs are included in the GUIC Rider and the basis for its inclusion.

Response:

The "Legacy Project" category of sewer inspections includes the mitigation work specifically related to previous gas installations programs that are covered under the Commission-approved sewer mitigation cost deferral mechanism. In 2010, the Commission authorized:

> *The Company to use deferred accounting treatment for the external operating and maintenance costs incurred to implement the inspection and remediation plan submitted to the Minnesota Office of Pipeline Safety in response to that Office's Notice of Probable Violation following the natural gas explosion of February 1, 2010.*
> (Commission Order, Docket No. G002/M-10-422)

The Commission's Order allowed the Company to seek rate recovery in a future filing. In the Company's initial GUIC Rider proceeding, Docket No. G002/M-14-336, the Commission approved recovery of the deferred sewer mitigation costs over five years. The Company has been ratably recovering these costs in all subsequent GUIC Rider dockets. This year's docket represents the final year of sewer mitigation deferred cost recovery.

Requests for inspection that are received from a customer, community, plumber, and other external resources fall into our "Emergency" category. "Cleared by Maps" refers to potential conflict areas which were identified by utilizing gas map and as-built records and comparing this to information available from various communities in our Gas Service Territory.

The "Legacy Project", "Emergency", and "Cleared by Maps" categories of work are all included in our GUIC Rider request. The work in each of these categories qualifies for the GUIC Rider, as it is being completed on existing facilities in order to respond to a Minnesota Office of Pipeline Safety (MNOPS) Notice of Probable Violation issued in 2010 requiring us to propose a mechanism for finding and mitigating sewer/natural gas line conflicts. In addition, the work follows guidance issued by the Pipeline Hazardous Materials Safety Administration (DIMP Enforcement Guidance, 49 CFR Part 192, Subpart P) to implement safety plans to reduce the risk to customers and minimize the threat of future cross bores in sewer lines.

"New Construction" refers to any new gas installation after January 1, 2010 that we clear prior to introducing gas to newly installed facilities. As this effort is directly related to the construction of new facilities and not existing facilities, these are not eligible for GUIC recovery and our not included in our Rider request.

Preparer:	Stephen Martz
Title:	Director, Gas Engineering
Department:	Gas Engineering & Operations
Telephone:	714-595-1068
Date:	February 4, 2019

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

Xcel Energy		Information Request No. 46
Docket No.:	G002/M-18-692	
Response To:	MN Department of Commerce	
Requestor:	Dorothy Morrissey/ Danielle Winner	
Date Received:	February 1, 2019	

Question:

Topic: Revenue Requirement Impact – GUIC Replaced Assets
Reference(s): Table 1 of Petition, page 20

A. Regarding the "Less: ADIT on Retired Assets" of $(0.70) million:

  i. Please explain how the $(0.70) million amount was derived;

  ii. Please explain if the $(0.70) million amount includes both deferred tax asset and deferred tax liability amounts.
    a. Please explain the accounting/expense activity driving the deferred tax asset component.
    b. Please explain the accounting/expense activity driving the deferred tax liability component.

B. Please explain the "Annual Deferred Tax Impact" and the basis for the $(0.02) million adjustment.

Response:

A. As was acknowledged in our Petition, the amount of retirements estimated for 2018 and 2019 were primarily based on retirement information from 2012 through 2017, which was information provided as Attachment A to our Reply Comments in the 2018 GUIC Rider filing (Docket No. G002/M-17-787). This estimate was necessary, as actual retirement information was not available for 2018 and 2019 at the time our Petition was filed.

i. In order to determine the Accumulated Deferred Income Tax (ADIT) for our estimate of retired assets, we initially calculated an ADIT factor for assets retired from 2012 through 2017. This percentage, 6.95 percent was calculated by taking the ADIT on the retired assets, $445,107 and dividing it by the value of the retired assets, $6,402,254. This ADIT factor was then multiplied by the total annual retirements estimated from 2012 through 2019, $10,105,876, to arrive at our estimated ADIT on retired assets of $702,596.

ii. Our estimate for ADIT on assets retired between 2012 and 2019 did not separate the deferred tax assets and deferred tax liability amounts associated with the assets; it was viewed as a net deferred tax liability. The majority of the deferred taxes for gas assets are deferred tax liabilities. Please see our response to Part A.i. above.

a. N/A
b. N/A

B. The annual deferred tax impact represents an estimate of the amount of deferred tax that would have been incurred in 2019 had the retired assets still been in-service.

As with the calculation of ADIT, the Company did not have actual annual deferred tax information regarding assets retired in 2018 and 2019. Once again, in order to calculate this amount, the Company calculated an annual deferred tax factor based on retirement information from 2012 through 2017. The factor was calculated at 0.21 percent. The factor was calculated by taking the annual deferred tax on the 2012 through 2017 retired assets, $13,265, and dividing it by the total retirements from 2012 through 2017. The factor was then multiplied by the total retirements estimated from 2012 through 2019 to arrive at our estimated annual deferred tax impact of $20,939.

Preparer: Brandon Kirschner
Title: Regulatory Policy Specialist
Department: NSPM Regulatory
Telephone: 612-215-5361
Date: February 11, 2019

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

Xcel Energy Information Request No. 16
Docket No.: G002/M-18-692
Response To: MN Department of Commerce
Requestor: Dorothy Morrissey / Danielle Winner
Date Received: January 8, 2019

Question:

Topic: Prorated Accumulated Deferred Income Tax
Reference(s): Petition, pp. 35-36

Please explain why the Accumulated Deferred Income Tax balance determined for ratemaking purposes in the Petition would be subject to the proration methodology if the recovery rate is proposed to go into effect after the test period.

Response:

The Company calculated the forecasted portions of 2018 and 2019 revenue requirements utilizing the new methodology for the proration of ADIT, in accordance with our understanding of the proration formula in IRS regulation section 1.167(1)-1(h)(6).

Subsequent analysis of the collection period to be used in this filing changed the application of ADIT proration. Since the projected rate will go into effect after the projected test year period, proration is not required. The Company will reduce the GUIC revenue requirements by the proration amounts of $188 listed on page 36 and Attachment R of the petition in final compliance.

Preparer: Mary Pope
Title: Senior Rate Analyst
Department: Revenue Requirements North
Telephone: 612-330-6574
Date: January 19, 2019

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

Xcel Energy		Information Request No. 38
Docket No.:	G002/M-18-692	
Response To:	MN Department of Commerce	
Requestor:	Dorothy Morrissey/ Danielle Winner	
Date Received:	January 18, 2019	

Question:

Topic: 2017 Plant in Service
Reference(s): Petition Attachments F and G

TIMP revenue requirements, Attachment G, page 1 reports 2017 year end plant in service total of $66,781,746. Attachment F reports that the 2017 year-to-date TIMP capital expenditures total $65,838,601 ($59,047,226 + $6,791,375). Please identify and explain the reason why the plant-in-service amount used for calculating the GUIC rider TIMP revenue requirements exceeds the Company's total TIMP capital expenditures.

Response:

Plant In-Service amounts provided in Petition Attachment G reflects an accumulation of capitalized projects over time. This includes Construction Work in Progress (CWIP) Expenditures (excluding Internal Labor) plus Allowance for Funds Used During Construction (AFUDC) from previous year and the current year for completed projects. Petition Attachment F provides only the CWIP Expenditures (excluding Internal Labor), which represents the expenditures only for that period of time.

Preparer: Mary Pope
Title: Senior Rate Analyst
Department: Revenue Requirements North
Telephone: 612-330-6574
Date: January 28, 2019

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

Xcel Energy		Information Request No. 47
Docket No.:	G002/M-18-692	
Response To:	MN Department of Commerce	
Requestor:	Dorothy Morrissey/ Danielle Winner	
Date Received:	February 1, 2019	

Question:

Topic: Low-risk work done as part of high- or medium-risk project
Reference(s): n/a

The Company indicated that it may replace/renew lower risk infrastructure as part of a high- or medium-risk ranked project to minimize disruption to the local community (Attachment D2(a), page 2).

By the high-level TIMP/DIMP program name, please provide the portion of capital/O&M costs for each TIMP and DIMP project included in the GUIC recovery request that is attributed to replacement/renewal of low-risk scored infrastructure.

Response:

The DIMP Poor Performing Mains and Services Program is the only program where lower-risk pipe segments in the same city block as higher-risk segments may be replaced/renewed as part of the same project. In addition to minimizing disruption to the local community, replacing these lower-risk pipe segments also streamlines the construction process, resulting in a more efficient and cost-effective replacement.

A typical replacement project that includes lower-risk pipe segments in the same block could include a maximum of 500 feet of additional pipe replacement. The majority of the Poor Performing Main and Service replacements are installed using the directional bore installation method. With this method, the cost of the bore does not materially change by adding an additional length of bore to include the low-risk section. As such, the additional construction cost associated with these short sections of pipe is essentially just the cost of materials ($400 - $1,200, depending on pipe diameter). In fact, in the case where the low-risk portion of the line is between two medium- or high-risk sections, it is actually cheaper to simply include the low-risk portion of the line. To "skip" that portion of the line would result in the Company incurring excavation, tie-in, and reclamation costs twice due to having two bores rather than one. Based on comparison of existing unit costs, the Company estimates these costs to be approximately $24,000 per segment. As a result, the inclusion of this work with adjacent high- or medium-risk projects ultimately represents a net cost savings.

Further, the costs to return to these short sections of pipe at such time that they rise to high-risk would be expected to be three to four times the unit cost of the original project, depending on the location of the segment.

Preparer:	Ray Gardner
Title:	Director
Department:	Gas Integrity Management Programs
Telephone:	303-571-3904
Date:	February 11, 2019

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

Xcel Energy		Information Request No. 20
Docket No.:	E002/M-18-692	
Response To:	MN Department of Commerce	
Requestor:	Dorothy Morrissey, Danielle Winner	
Date Received:	January 11, 2019	

<u>Question:</u>

Topic: Removal Costs
Reference(s): Petition, Attachments G and H

A. Reference TIMP Attachment G, only the "Total" column amounts, pages 1 – 4. For each of rate base components, please breakout the debited and/or credited dollar amounts relevant to the inclusion of removal costs.

B. Reference DIMP Attachment H, only the "Total" column amounts, pages 1 – 4. For each of rate base components, please breakout the debited and/or credited dollar amounts relevant to the inclusion of removal costs.

<u>Response:</u>

Please see Attachment A provided with this response for the TIMP and DIMP removal costs included in the "Total" columns of petition Attachments G and H, by rate base component.

Preparer: Mary Pope
Title: Senior Rate Analyst
Department: Revenue Requirements North
Telephone: 612-330-6574
Date: January 24, 2019

Northern States Power Company

Removal Costs Included in Petition Attachment G

Docket No. G002/GR-18-692
DOC Information Request No. 20
Attachment A - Page 1 of 2

	As Filed in Attachment G				Removal Costs Only			
TIMP - Capital Revenue Requirements	Total 2017	Total 2018	Total 2019	Total 2020	Total 2017	Total 2018	Total 2019	Total 2020
Rate Base								
CWIP	-	-	-	-	-	-	-	-
Plant In-Service	66,781,746	74,551,685	85,825,266	138,826,768	-	-	-	-
Less Accumulated Book Depreciation Reserve	2,379,149	(1,345,805)	(7,032)	1,077,105	(1,359,907)	(6,467,205)	(6,609,370)	(7,165,834)
Less Accumulated Deferred Taxes	8,052,591	8,393,489	9,470,598	11,238,799	3,493,218	2,996,700	3,161,616	3,353,876
End Of Month Rate Base	56,350,007	67,504,000	76,361,699	126,510,864	(2,133,311)	3,470,505	3,447,754	3,811,958
Average Rate Base (Prior Mo + Cur Month/2)								
Return on Rate Base								
Debt Return (Avg RB * Wtd Cost of Debt)	1,194,485	1,390,388	1,534,624	1,770,527	(48,426)	78,086	77,574	85,769
Equity Return (Avg RB * Wtd Cost of Equity)	2,499,473	3,244,239	3,669,456	4,233,527	(101,332)	182,202	185,489	205,083
Total Return on Rate Base	3,693,958	4,634,627	5,204,079	6,004,055	(149,758)	260,288	263,064	290,852
Income Statement Items								
AFUDC Pre-Eligible	-	-	-	-	-	-	-	-
Operating Expenses	-	-	-	-	-	-	-	-
Property Taxes	1,009,577	1,135,079	1,267,144	1,458,759	-	-	-	-
Book Depreciation	1,483,608	1,388,751	1,475,179	1,646,160	-	-	-	-
Deferred Taxes	2,626,422	356,219	1,109,508	1,797,805	142,915	(496,518)	164,916	192,260
Gross Up for Income Tax (see below)	(889,818)	954,124	436,319	151,570	(217,539)	585,774	(95,335)	(115,644)
Total Income Statement Expense	4,229,790	3,834,174	4,288,150	5,054,294	(74,623)	89,256	69,581	76,616
Total Revenue Requirement	**7,923,747**	**8,468,800**	**9,492,230**	**11,058,349**	**(224,382)**	**349,544**	**332,645**	**367,469**
Capital Structure								
Weighted Cost of Debt	2.27%	2.25%	2.25%	2.25%	2.27%	2.25%	2.25%	2.25%
Weighted Cost of Equity	4.75%	5.25%	5.38%	5.38%	4.75%	5.25%	5.38%	5.38%
Required Rate of Return	7.02%	7.50%	7.63%	7.63%	7.02%	7.50%	7.63%	7.63%
Current Income Tax Calculation								
Equity Return	2,499,473	3,244,239	3,669,456	4,233,527	(101,332)	182,202	185,489	205,083
Book Depreciation	1,483,608	1,388,751	1,475,179	1,646,160	-	-	-	-
Deferred Taxes	2,626,422	356,219	1,109,508	1,797,805	142,915	(496,518)	164,916	192,260
Less Tax Depreciation	7,915,576	2,657,167	5,579,029	8,447,012	(349,881)	1,766,586	(586,763)	(684,052)
Plus CPI-Tax Interest (If Applicable)	45,014	33,449	406,620	1,145,296	-	-	-	-
Total	(1,261,059)	2,365,491	1,081,735	375,777	(308,298)	1,452,269	(236,358)	(286,708)
Tax Rate (T/(1-T)	0.705611	0.403351	0.403351	0.403351	0.705611	0.403351	0.403351	0.403351
Gross Up for Income Tax	(889,818)	954,124	436,319	151,570	(217,539)	585,774	(95,335)	(115,644)

Northern States Power Company

Removal Costs Included in Petition Attachment H

Docket No. G002/GR-18-692
DOC Information Request No. 20
Attachment A - Page 2 of 2

	As Filed in Attachment H				Removal Costs Only			
DIMP - Capital Revenue Requirements	Total 2017	Total 2018	Total 2019	Total 2020	Total 2017	Total 2018	Total 2019	Total 2020
Rate Base								
CWIP	-	-	-	-	-	-	-	-
Plant In-Service	35,605,770	74,190,519	92,415,881	108,811,467	-	-	-	-
Less Accumulated Book Depreciation Reserve	(5,709,218)	(5,960,180)	(5,685,658)	(4,540,128)	(6,952,476)	(8,173,186)	(9,629,824)	(10,530,674)
Less Accumulated Deferred Taxes	6,423,723	7,592,200	8,910,753	10,518,121	3,020,855	3,483,281	3,735,393	3,990,250
End Of Month Rate Base	34,891,265	72,558,498	89,190,786	102,833,474	3,931,621	4,689,904	5,894,432	6,540,424
Average Rate Base (Prior Mo + Cur Month/2)								
Return on Rate Base								
Debt Return (Avg RB * Wtd Cost of Debt)	623,704	944,685	1,794,310	2,114,953	89,248	105,523	132,625	147,160
Equity Return (Avg RB * Wtd Cost of Equity)	1,305,108	2,204,265	4,290,396	5,057,087	186,752	246,220	317,120	351,875
Total Return on Rate Base	1,928,812	3,148,950	6,084,706	7,172,039	276,000	351,743	449,745	499,034
Income Statement Items								
AFUDC Pre-Eligible	-	-	-	-	-	-	-	-
Operating Expenses	-	-	-	-	-	-	-	-
Property Taxes	395,590	605,186	1,261,005	1,570,779	-	-	-	-
Book Depreciation	781,237	943,426	1,715,366	2,046,442	-	-	-	-
Deferred Taxes	4,221,091	1,220,993	1,322,937	1,620,152	1,351,515	462,427	252,111	254,857
Gross Up for Income Tax (see below)	(3,369,664)	(319,119)	373,563	594,683	(1,249,267)	(377,796)	(132,205)	(121,020)
Total Income Statement Expense	2,028,254	2,450,486	4,672,871	5,832,056	102,248	84,631	119,906	133,837
Total Revenue Requirement	**3,957,066**	**5,599,436**	**10,757,577**	**13,004,095**	**378,248**	**436,374**	**569,651**	**632,872**
Capital Structure								
Weighted Cost of Debt								
Weighted Cost of Equity								
Required Rate of Return								
Current Income Tax Calculation								
Equity Return	1,305,108	2,204,265	4,290,396	5,057,087	186,752	246,220	317,120	351,875
Book Depreciation	781,237	943,426	1,715,366	2,046,442	-	-	-	-
Deferred Taxes	4,221,091	1,220,993	1,322,937	1,620,152	1,351,515	462,427	252,111	254,857
Less Tax Depreciation	11,135,147	5,369,609	6,422,732	7,268,184	(3,308,741)	(1,645,289)	(896,998)	(906,768)
Plus CPI-Tax Interest (If Applicable)	52,186	209,755	20,181	18,857	-	-	-	-
Total	(4,775,524)	(791,169)	926,148	1,474,354	(1,770,474)	(936,643)	(327,766)	(300,036)
Tax Rate (T/(1-T)	0.705611	0.403351	0.403351	0.403351	0.705611	0.403351	0.403351	0.403351
Gross Up for Income Tax	(3,369,664)	(319,119)	373,563	594,683	(1,249,267)	(377,796)	(132,205)	(121,020)

U.S. Department of Transportation
Pipeline and Hazardous Materials Safety Administration

1200 New Jersey Ave, S.E.
Washington, D.C. 20590

JAN 2 3 2015

Mr. Joseph P. Como
Acting Director, Office of Ratepayer Advocates
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

Dear Mr. Como:

In a letter to the Pipeline and Hazardous Materials Safety Administration (PHMSA) dated December 4, 2013, the Office of Ratepayer Advocates (ORA) requested a regulatory interpretation of 49 CFR 192.619 regarding the maximum allowable operating pressure (MAOP) for natural gas pipelines. Specifically, ORA asked if the consideration of design pressure in § 192.619(a)(1) is required for pipelines that were placed in service before July 1, 1970. ORA asked whether an operator must use the design pressure in § 192.619(a)(1) as the MAOP for a segment of pipeline that was placed in service before July 1, 1970, if the design pressure is the lowest pressure from the methods set forth in § 192.619(a). In addition, ORA informed PHMSA that the California Public Utilities Commission (CPUC) no longer permits gas operators within its jurisdiction to rely on the "Grandfather Clause" in § 192.619(c).

ORA attached PHMSA's letter objecting to the Oklahoma Corporation Commission's (OCC) Waiver of Compliance, PHP-08-0074, dated March 17, 2008, and stated that it believes that letter to mean that an operator must calculate and consider the design pressure to determine the MAOP of pipelines installed prior to July 1, 1970, as well as after that date. ORA asked if its understanding is correct. ORA stated that the letter's discussion was about distribution lines and asked PHMSA to confirm that a MAOP calculated under § 192.619(a) cannot exceed design pressure for transmission pipelines installed prior to July 1, 1970.

ORA informed PHMSA that in a recent hearing held by the CPUC, Pacific Gas & Electric Company (PG&E) asserted that it is not required to consider design pressure for a pipeline placed in service before July 1, 1970, that has been subject to a Subpart J strength test. ORA stated that PG&E's reasoning was that "§ 192.619(a)(1) is forward-looking and applies only to segments of new pipeline installed after 1970, the year the Federal regulations became effective." ORA's letter stated that PG&E believes that the regulations allow it to operate a pipeline placed in service prior to July 1, 1970, at a MAOP based on its strength test pressure under § 192.619(a)(2) even if the design pressure is lower.

The Pipeline and Hazardous Materials Safety Administration, Office of Pipeline Safety provides written clarifications of the Regulations (49 CFR Parts 190-199) in the form of interpretation letters. These letters reflect the agency's current application of the regulations to the specific facts presented by the person requesting the clarification. Interpretations do not create legally-enforceable rights or obligations and are provided to help the public understand how to comply with the regulations.

ORA stated that it disagrees with PG&E's interpretation because:

1. Section 192.619(a) does not state the design pressure is inapplicable to pipelines installed before July 1, 1970;
2. The MAOP requirements under § 192.619 are part of Subpart L, which govern safe operating conditions, and the requirement in § 192.619(a) appears to be a mandatory safety precaution; and
3. ORA believes the above mentioned PHMSA letter to the OCC confirms that the design pressure provision applies to lines placed in operation prior to July 1, 1970.

ORA asks the following questions, and PHMSA's answers are below:

Question 1: When validating the MAOP of pipeline segments placed in operation before July 1, 1970, and still in operation today, is the operator required to calculate and consider the design pressure pursuant to § 192.619(a)(1)?

Response: Section 192.619(a) states: "No person may operate a segment of steel or plastic pipeline at a pressure that exceeds a MAOP determined under paragraph (c) or (d) of this section, or the lowest of the following: …." Paragraphs (a)(1) – (a)(4) then specify four pressures which must be calculated in order to determine the MAOP. Therefore, the answer is yes.

The operator of a pipeline that was placed into service before July 1, 1970, must determine MAOP in accordance with § 192.619. If § 192.619(a) is used to determine MAOP, the operator must calculate the design pressure in accordance with § 192.619(a)(1), and use the design pressure or a lower pressure as the MAOP if that is the lowest of the four pressures described in paragraphs (a)(1) – (a)(4). If applicable, an operator may also use the "Grandfather Clause" in § 192.619(c) to determine the pipeline segment's MAOP.

Over time, changes in the population density surrounding a pipeline segment will affect the class location and MAOP of a pipeline. Section 192.613 requires operators to have a procedure for continuing surveillance of its facilities to determine and take appropriate action concerning changes in class location. When there are changes to population density along a pipeline segment, § 192.609 requires the operator to conduct a class location study, and § 192.611 details the requirements for confirming or revising the MAOP according to the new class location.

Paragraph (d) of § 192.611 requires the operator to confirm or revise the MAOP within 24 months of the change in class location. If an operator fails to confirm or revise the MAOP within 24 months of the change in class location, then § 192.611 cannot be used and the pipeline segment MAOP must be calculated in accordance with § 192.619(a), using the design factor that appears in § 192.111 for the new class location.

The CPUC may impose more stringent MAOP regulations by establishing them through state law. PHMSA does not interpret state regulations.

Question 2: If the answer to Question 1 is yes, must the operator use its design pressure as the MAOP when the design pressure is the lowest pressure calculation required by § 192.619(a)?

Response: Yes, if the Grandfather Clause in § 192.619(c) or the alternative MAOP option in § 192.619(d) is not applicable. If the operator uses § 192.619(a) to determine MAOP, the MAOP would be equal to the lowest value calculated according to paragraphs (a)(1) – (a)(4).

For a pre-July 1, 1970 pipeline segment, the operator must determine the MAOP in accordance with § 192.619(a) unless the operator has documentation that meets the § 192.619(c) requirements for the entire pipeline segment and elects to use it to establish MAOP.

If an operator uses § 192.619(a) to determine the pipeline segment MAOP, the operator must have records to substantiate the calculations required in paragraphs (a)(1) – (a)(4), including the properties of pipe and pipeline components. Paragraph (a)(1) requires that the pipeline design pressure be determined in accordance with Subparts C and D, including § 192.105 which states that the pipeline design pressure must be based upon the current class location design factor and the actual pipe properties which include yield strength (grade), wall thickness, longitudinal joint factor (seam type), maximum operating temperature and pipe diameter. If the pipeline segment contains pipeline components such as bends, fittings, flanges or valves, the operator would need to determine the design pressure of these pipeline components in accordance with applicable sections of Subparts C and D of Part 192.

If an operator uses the Grandfather Clause in § 192.619(c) to establish the MAOP, the operator must have documentation of the pipeline segment's condition and operating and maintenance history, including historical pressure records for the maximum operating pressure to which the entire pipeline segment was subjected during the five years prior to July 1, 1970. The Grandfather Clause in § 192.619(c) cannot be used to determine the MAOP after a change in class location. Section 192.611 can be used to revise the MAOP within 24 months after a class location change; after that deadline, the MAOP must be revised according to § 192.619(a).

Sections 192.517 and 192.603 require that all records regarding the pipeline MAOP determination be kept for the life of the pipeline segment, including records of pipe properties, pipeline component properties, pressure test records, class location studies, current class location designation, and operating history.

Question 3: Does § 192.619 apply to both transmission lines and distribution lines?

Response: Yes. The requirements in § 192.619 apply to both distribution and transmission natural gas pipelines. Section 192.621 contains different standards that apply only to high pressure distribution systems. States that regulate intrastate natural gas transmission pipelines and natural gas distribution pipelines have the right to implement state pipeline regulations that exceed the requirements in Part 192.

If we can be of further assistance, please contact John Gale of my staff at 202-366-0434.

Sincerely,

Jeffrey D. Wiese
Associate Administrator for
Pipeline Safety

The Pipeline and Hazardous Materials Safety Administration, Office of Pipeline Safety provides written clarifications of the Regulations (49 CFR Parts 190-199) in the form of interpretation letters. These letters reflect the agency's current application of the regulations to the specific facts presented by the person requesting the clarification. Interpretations do not create legally-enforceable rights or obligations and are provided to help the public understand how to comply with the regulations.

ORA

Office of Ratepayer Advocates
California Public Utilities Commission

JOSEPH P. COMO
Acting Director

505 Van Ness Avenue
San Francisco, California 94102
Tel: 415-703-2381
Fax: 415-703-2057
http://ora.ca.gov

December 4, 2013

DEC 11 2013

VIA US MAIL

John Gale
Director, Standards and Rulemaking
U.S. Department of Transportation
Pipeline and Hazardous
Materials Safety Administration
East Building, Second Floor
1200 New Jersey Avenue SE
Washington, D.C. 20590

Dear Mr. Gale,

The Office of Ratepayer Advocates (ORA) at the California Public Utilities Commission is writing to the Pipeline and Hazardous Materials Safety Administration (PHMSA) to request an interpretation of the regulation on determining maximum allowable operating pressure (MAOP) for natural gas pipelines, 49 C.F.R. § 192.619. Specifically, do the design MAOP requirements of 49 C.F.R. § 192.619(a)(1) apply to pipelines in service today that were placed in service before July 1, 1970?[1] If a segment of pipeline was placed in service before July 1, 1970, and the design MAOP is the lowest MAOP from the allowable methods of calculating MAOP set forth in § 192.619(a), must the operator operate that line under the design MAOP? (Please note that the California Public Utilities Commission (CPUC) no longer permits gas operators within its jurisdiction to rely on § 192.619(c), the "grandfather clause," to validate MAOP.[2])

In PHMSA's Waiver of Compliance Order PHP 08-0074, dated March 17, 2008, PHMSA provided an interpretation of 192.619(a)'s MAOP requirements. Under that interpretation, PHMSA acknowledged that:

---

[1] As PHMSA may be aware, in the aftermath of the San Bruno, California pipeline explosion disaster, the California Public Utilities Commission (CPUC) ordered its regulated gas utilities to begin extensive evaluations of records and hydrotesting to verify the safety of natural gas pipelines. In particular, gas operators were ordered to validate the MAOP of their transmission lines without relying on § 192.619(c) (the "grandfather clause"). *See* California Public Utilities Commission Decision 11-06-017, pp. 18, 31 (June 9, 2011), *available at* http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/137309.PDF.

[2] *See* California Public Utilities Commission Decision 11-06-017, pp. 18, 31 (June 9, 2011), *available at* http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/137309.PDF.

> The Federal pipeline safety regulations in § 192.619(a) limit the MAOP of a pipeline installed prior to July 1, 1970, to **the lowest of** the following four pressures:
>
> - The design pressure of the weakest element in the segment per §192.619(a)(1);
>
> - The pressure obtained by dividing the pressure to which the segment was tested after construction by the applicable factor per § 192.619(a)(2);
>
> - The highest actual operating pressure the segment was subjected to during the 5 years preceding July 1, 1970 per § 192.619(a)(3); or
>
> - The pressure determined by the operator to be the maximum safe pressure after considering the history of the segment per § 192.619(a)(4).
>
> A pipeline operator would need data to support all four pressures listed above to establish the MAOP of a pipeline segment using § 192.619(a).[3]

ORA understands this interpretation to mean that an operator must calculate and consider the design MAOP to determine the MAOP of pipelines installed prior to July 1, 1970 (as well as after that date). Could PHMSA verify that ORA's understanding is correct?

PHMSA's Waiver of Compliance Order PHP 08-0074, cited above, specifically addresses distribution lines. If the answer to the previous question is yes, does the same requirement to calculate design MAOP for pipelines installed prior to July 1, 1970 also apply to transmission lines? ORA's understanding is that the Subpart L requirements regarding how to determine MAOP apply both to distribution and transmission lines. Section 192.601 refers to "the minimum requirements for the operation of *pipeline facilities*" and § 192.603(a) requires that "[n]o person may operate a *segment of pipeline* unless in accordance with this subpart" without making a distinction between transmission lines or distribution lines.

In a recent hearing held by the CPUC, Pacific Gas & Electric Company (PG&E) asserted that it is not required to consider design MAOP for a pipeline placed in service before July 1, 1970 that has been subject to a Subpart J strength test . PG&E states that § 192.619(a)(1) is forward-looking and applies only to segments of new pipeline installed after 1970, the year the federal regulations became effective. In PG&E's opinion, the regulations allow it to operate a line placed in use prior to July 1, 1970 based on its strength test pressure MAOP, under §192.619(a)(2), even when the design MAOP is lower.

[3] PHP 08-0074, p. 1 (March 17, 2008) (emphasis added).

ORA interprets the regulations differently. ORA's understanding is that when an operator is directed to validate the MAOP of a line operating *today*, regardless of when it was installed, it must use the MAOP determined by § 192.619(a); that is, the lowest value of pressure calculated using § 192.619(a)(1), (2), (3) or (4). Thus, if the design MAOP is lower than test MAOP, the design MAOP must be used unless one of the other methods permitted under § 192.619(a) yields a result that is lower. ORA wishes to verify that its understanding is correct.

ORA has taken this position for a number of reasons. First, Section 192.619(a) does not state that the design MAOP method is inapplicable to pipelines installed before July 1, 1970. Second, the MAOP requirements under § 192.619 are part of Subpart L, which governs safe operating conditions. The "operator must use the lower of . . . . ." provision of § 192.619(a) appears to be a mandatory safety precaution. Third, PHP 08-0074, referenced above, confirms that the design MAOP provision applies to lines placed in operation prior to July 1, 1970.

In sum, the Office of Ratepayer Advocates asks for the following interpretations:

1. When validating the MAOP of pipeline segments placed in operation before July 1, 1970 that are still operating today, is the operator required to calculate and consider the design MAOP pursuant to § 192.619(a)(1)?

2. If the answer to Question 1 is yes, must the operator use its design MAOP when the design MAOP is the lowest MAOP calculation required by § 192.619(a)?

3. Does § 192.619 apply both to transmission lines as well as distribution lines?

Sincerely,

K Paull for J. Como

Joseph P. Como
Acting Director
Office of Ratepayer Advocates
California Public Utilities Commission

Enclosure

U.S. Department
of Transportation

**Pipeline and Hazardous
Materials Safety
Administration**

1200 New Jersey Avenue, SE
Washington, D.C. 20590

MAR 17 2008

Mr. Dennis Fothergill
Regulatory Program Manager
Pipeline Safety Department
Transportation Division
Oklahoma Corporation Commission
P.O. Box 52000
Oklahoma City, OK 73152-2000

Dear Mr. Fothergill:

The Pipeline and Hazardous Materials Safety Administration (PHMSA) reviewed your letter of January 23, 2008, notifying us that the Oklahoma Corporation Commission (Commission) granted CenterPoint Energy Resources Corp doing business as CenterPoint Energy Oklahoma Gas (CenterPoint) a waiver of compliance from state regulation 49 CFR 192.619(a)(3) [as adopted by the Commission in OAC 165: 20-5-21] for 138 low-pressure distribution system pipeline segments in Oklahoma. The regulations in § 192.619(a)(3) limit the maximum allowable operating pressure (MAOP) of a steel or plastic pipeline segment installed prior to July 1,1970, to the highest actual operating pressure the segment was subjected to during the 5 years preceding July 1, 1970.

The Federal pipeline safety regulations in § 192.619(a) limit the MAOP of a pipeline installed prior to July 1, 1970, to the lowest of the following four pressures:

- The design pressure of the weakest element in the segment per § 192.619(a)(1);
- The pressure obtained by dividing the pressure to which the segment was tested after construction by the applicable factor per § 192.619(a)(2);
- The highest actual operating pressure the segment was subjected to during the 5 years preceding July 1, 1970 per § 192.619(a)(3); or
- The pressure determined by the operator to be the maximum safe pressure after considering the history of the segment per § 192.619(a)(4).

A pipeline operator would need data to support all four pressures listed above to establish the MAOP of a pipeline segment using § 192.619(a).

When these rules were first promulgated in 1970, PHMSA recognized that an operator may not have all the pressure data needed for existing pipelines. Therefore, we included in the rules a "grandfather clause" to allow pipeline operators to establish the MAOP of an existing pipeline segment in satisfactory condition, and considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the 5 years prior to July 1, 1970. This "grandfather clause" is codified in § 192.619(c), not § 192.619(a)(3).

The operator at the time the regulations were promulgated in 1970 should have established the MAOP for each of these 138 low-pressure segments by using either § 192.619(a) or § 192.619(c). Moreover, there are additional MAOP restrictions for low-pressure distribution systems in § 192.623. Subsequently, the MAOP of these segments can only be increased in accordance with 49 CFR Part 192, Subpart K- Uprating, not § 192.619(a) or § 192.619(c), and with consideration of § 192.623. Accordingly, if CenterPoint wishes to increase the existing MAOPs, they should seek relief from the uprating regulations and the low-pressure distribution system regulations, if required, not from § 192.619(a)(3).

Unfortunately, no data was submitted with the waiver grant to PHMSA regarding the existing MAOPs of these 138 segments. Nor is it clear why CenterPoint is seeking MAOP relief, if as you state in your letter, *"CenterPoint requested the MAOP for these 138 low pressure gas distribution pipeline segments be established at 1.00 psig, which is the current and historical maximum operating pressure for these segments."* If these segments have been historically operated up to 1.00 psig, then the existing MAOPs must already be at least 1.00 psig or the segments have been historically operated in violation of the pipeline safety regulations. If so, this needs to be addressed before a waiver is granted.

PHMSA is unable to fully evaluate this waiver grant without additional information. For example, why is CenterPoint establishing MAOPs in 2008 for pipeline segments that have been operating for over 50 years? Are there any open enforcement actions regarding the historical operation of these segments up to 1.00 psig? How does CenterPoint propose to meet the requirements in § 192.623, when it is known that many gas appliances are rated for 0.5 psig or less, not 1.00 psig?

For the reasons stated above, PHMSA objects to this waiver and the Commission's order is stayed. The Commission may appeal this matter. However, because the waiver of § 192.619(a)(3) is inappropriate, PHMSA suggests that CenterPoint resubmit its application to the Commission and that the Commission grant a new waiver, if appropriate. The new waiver grant must specifically identify the state pipeline safety regulation the Commission is waiving and must include new information from the petitioner to justify granting the waiver. This new information should include, at a minimum, technical evidence to substantiate that an MAOP of 1.00 psig for these 138 low-pressure distribution pipeline segments would result in equivalent or greater safety than an MAOP established using the methods currently allowed in the Federal pipeline safety regulations in 49 CFR Part 192.

If you wish to discuss this waiver or any other pipeline safety matter, my staff would be pleased to assist you. Please call Barbara Betsock, Acting Director of Regulations at 202-366-4361 for regulatory matters or Alan Mayberry, Director of Engineering and Emergency Support at 202-366-5124 for technical matters.

Sincerely,

William A Gute
For

Jeffrey D. Wiese
Associate Administrator
for Pipeline Safety

corrosion monitoring under § 192.465 for the life of the pipe. Most of these commenters declared that 5 years would be adequate, but did not explain why a longer period is excessive. Lacking any convincing documentation to the contrary, RSPA believes the current rule should stay in effect. In our experience, a history of corrosion monitoring sheds light on the possible causes of a pipeline's condition. Such history has proven to be a valuable resource in deciding the extent and kind of remedial action needed when corrosion problems emerge on a pipeline.

Regarding the proposed 5-year retention time for records other than those required by §§ 192.465 (a) and (e) and 192.475(b), two commenters said the minimum time should be 3 years to coincide with the longest interval between inspections. Two others suggested that instead of a set time, we adopt a performance standard for record retention, basing it on the time needed to observe trends, inquire into compliance, or collect superseding data. All these comments provide a reasonable basis for record retention. However, our main concern is that operators keep records for a period that is compatible with the occurrence of routine compliance investigations. Therefore, for simplicity and uniformity, we have decided to adopt the proposed 5-year minimum retention time.

The state agency that commented objected to the 5-year proposal on grounds that it would sacrifice information about why external or atmospheric corrosion control was not installed on pipelines under §§ 192.455, 192.457, and 192.479. RSPA believes the loss of this information after 5 years would not be significant, because the pipelines involved are covered by requirements for periodic inspections or tests for corrosion under §§ 192.465 and 192.481.

Section 192.553, General Requirements

(See previous discussion under § 192.14).

Section 192.607, Determination of Class Location and Maximum Allowable Operating Pressure

Because § 192.607 has no continuing effect and the deadlines for compliance have expired, RSPA proposed to remove § 192.607 from part 192.

Fourteen TPSSC members voted for the proposal and one member abstained.

Five operators, one pipeline-related association, and one state agency commented on the proposed removal of § 192.607. Four operators and the association favored the idea. One operator and the state agency disagreed with removal, believing the rule is needed to tie a pipeline's maximum allowable operating pressure (MAOP) to its class location. Similarly, the NAPSR report recommended that we only remove the past compliance deadlines from § 192.607, leaving the rest of the rule in place to regulate the relation of class location to stress level on high-stress pipelines.

Section 192.607 was a transitional requirement. Its purpose was to establish plans under which operators initially determined class locations and confirmed or revised the MAOPs of their high-stress pipelines commensurate with their class locations. Section 192.607 provides that the plans had to be executed in accordance with § 192.611. This latter section together with § 192.609 are sufficient to require that operators have up-to-date class location determinations for high-stress pipelines, and maintain the MAOPs of those lines commensurate with their class locations.

Accordingly, § 192.607 is removed from part 192.

Section 192.611, Change in Class Location

Section 192.611 requires confirmation or revision of a pipeline's MAOP within 18 months after a change in class location. RSPA proposed to reorganize § 192.611 to clarify the requirement that the MAOP resulting from confirmation or revision may not exceed the pipeline's previous MAOP. This requirement is currently set forth in § 192.611(a)(3)(ii), suggesting that it applies only to confirmations or revisions under paragraph (a)(3), which is not the intent.

Fourteen TPSSC members voted for the proposal and one member abstained.

Five operators and one pipeline-related association commented on the proposal; each agreed with the proposal. Section 192.611 is, therefore, adopted as proposed in the NPRM.

Section 192.614, Damage Prevention Program

To decrease excavation damage to pipelines, § 192.614(b)(2) requires operators to notify excavators and the public about the need to locate buried pipelines before excavating. The NPRM proposed to amend the rule to clarify that in contrast to the actual notification required for excavators, only general notification is required for the public. General notice can be given through newspapers, radio, television, or other means of mass communication, as appropriate for the public in the vicinity of the pipeline.

Fourteen TPSSC members voted for the proposal and one member abstained.

Six pipeline operators and two pipeline-related organizations commented. Seven commenters gave their full or qualified approval and one commenter opposed the proposal. The qualified and negative comments were that the rule should inform operators of the acceptable means of notification. We do not feel it is necessary for the rule to do so, however, because the available means of giving general public notice are well known. The amendment to paragraph (b)(2) is adopted as proposed.

Section 192.619, Maximum Allowable Operating Pressure: Steel or Plastic Pipelines

Section 192.619(a) prescribes six pressure limits for use in determining the MAOP of steel and plastic pipelines, the lowest of which establishes the MAOP. Paragraph (a)(4) limits the MAOP of furnace butt welded pipe to 60 percent of the mill test pressure. Paragraph (a)(5) limits the MAOP of other steel pipe to 85 percent of the highest test pressure to which the pipe has been subjected, whether by mill test or by the post installation test.

RSPA proposed to repeal paragraphs (a)(4) and (a)(5), primarily because mill tests are not an adequate MAOP consideration. However, to assure consideration of longitudinal joint efficiency, RSPA also proposed, in paragraph (a)(2)(iii), that the class location pressure limit under existing paragraph (a)(2)(ii) be reduced for furnace butt welded pipe and lap welded pipe.

Eleven TPSSC members voted for the proposal, one member supported it with a recommended change, two members opposed it, and one abstained. A member recommended that RSPA not adopt proposed paragraph (a)(2)(iii) because design pressure (under paragraph (a)(1)) adequately covers longitudinal joint concerns.

RSPA concurs with this view as explained below in response to public comment.

Thirteen operators, four pipeline-related associations, and one state agency commented on the proposed amendment. Two operators, one pipeline-related association, and one state agency commented that proposed paragraph (a)(2)(iii) could require operators to reduce the operating pressure of some pipelines or test them to higher pressures than they previously were tested, possibly damaging the pipelines. In addition, some commenters stated that proposed paragraph (a)(2)(iii) would duplicate use of longitudinal joint factors.

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

Xcel Energy		Information Request No.	21
Docket No.:	E002/M-18-692		
Response To:	MN Department of Commerce		
Requestor:	Dorothy Morrissey, Danielle Winner		
Date Received:	January 11, 2019		

Question:

Topic:	Capital Costs
Reference(s):	Docket No. G002/M-17-787, Xcel July 27, 2018 Reply Comments, Attachment C

In Attachment C of Xcel's July 27, 2018 Reply Comments in Docket No. G002/M-17-787, Xcel provided a table of 2017 Capital Charges by Work Order for MN GUIC Projects. Please provide an updated table of 2018 Capital Charges by Work Order for MN GUIC Projects, clearly identifying which costs are included in the currently proposed GUIC Rider.

Response:

Please see Attachment A to this response for a replication of Attachment C, using data from 2018.

Please note that Attachment A was prepared using the most recent available information for 2018 capital expenditures, internal labor, and RWIP. The level of detail necessary to prepare this attachment was not available for the data used to prepare the initial filing. The initial filing was prepared using data gathered in July 2018, which included six months of forecast data. Due to the data vintage used, the GUIC recoverable capital expenditures shown in this response are slightly different than the amount shown in our initial filing. The "Total GUIC Recoverable Costs" column in Attachment A to this response represents the current view of the capital costs included in our 2019 request.

The total GUIC recoverable 2018 capital expenditures based on the currently available data are $43.5 million. This amount is comparable to the total capital expenditures shown in Attachment F included with our Petition.

The numbers in this attachment will be updated when final 2018 information is available and we will provide that update with our Reply Comments in this docket.

Preparer:	Brandon Kirschner
Title:	Regulatory Policy Specialist
Department:	NSPM Regulatory
Telephone:	612-215-5361
Date:	January 25, 2019

Northern States Power Company
GUIC Capital Expenditures by Work Order
2018 Actuals

										Internal Labor (Not Eligible for GUIC Recovery)								
Work Order Number	Project Description	Contractor	Overheads	CIAC	Material	Other	Transportation	Budget	Salvage	Company Labor Loadings	Company OT Labor	Company ST Labor	Employee Expenses	Total Capital Costs	Less: Internal Labor	Less: RWIP	Less: Betterment Adjustment	Total GUIC Recoverable Costs
E.0000002.005	DIMP Service Renewals	$ 2,460	$ 7,789	$ -	$ 11,260	$ 27	$ -	$ -	$ -	$ 87	$ -	$ 390	$ -	$ 22,012	$ (477)	$ (78)	$ -	$ 21,457
E.0000002.043	NSPM Programmatic Service Repl	-	6	-	-	-	-	-	-	-	-	-	-	6	-	-	-	6
E.0000004.048	NSPM Pipe Trans and IMP - Dist FERC Acct	1,147,050	912,918	-	1,096	-	-	-	-	-	-	-	-	2,061,064	-	-	-	2,061,064
E.0000004.054	NSPM Install 6" and 4" Distribution Valves	(11)	(7)	-	(9)	(2)	(3)	-	-	(10)	(2)	(28)	-	(73)	40	(10,607)	-	(10,639)
E.0000007.002	MNGD Main Renewal-MN (Programmatic Main Repl)	(35,131)	(15,072)	-	(1,583)	1,105	-	-	-	-	-	-	-	(50,682)	-	10,936	-	(39,745)
E.0000007.006	Sartell Bridge Replacement	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10,727	-	10,727
E.0000007.045	MNGD Main Renewal-MN (Programmatic Main Repl)	(39,711)	(6,640)	-	(1)	-	-	-	-	-	-	-	-	(46,352)	-	(65,598)	-	(111,950)
E.0000007.053	IP Line Assessments	(103,471)	130,326	-	297	136,178	-	-	-	6,061	67	24,138	472	194,068	(30,738)	(1,974)	-	161,356
E.0000008.002	MNGM Main Reinforcement-MN (Repl Emergency Valves)	(2,562)	(160)	-	2,536	(264)	1,191	-	-	4,222	9,333	11,880	-	26,176	(25,435)	(23,571)	-	(22,831)
E.0000018.041	ASV/REV Instalation on High Pr	247,715	35,129	-	39,794	4,731	811	-	-	23,919	12,764	66,634	84	431,581	(103,401)	873	-	329,054
E.0000018.052	NSPM TIMP Mitigation of ILI Re	354,044	19,267	-	2,691	-	-	-	-	2,657	1,190	6,710	-	386,558	(10,556)	2,389,342	-	2,765,344
E.0000018.055	NSPM Pre 1950 Trans and IP Pip	3,167,515	306,409	-	423,294	5,400	709	-	-	5,776	7,837	16,645	154	3,933,737	(30,411)	(933,343)	-	2,969,984
E.0000018.102	NSPM Pipe Trans and IP - GUIC Bette	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(81,116)	-	(81,116)
E.0000030.002	EastMetro Pipe Repla. Proj Dis	332	8	-	-	-	-	-	-	-	-	-	-	340	-	-	-	340
E.0000030.009	EastMetro Pipe Repla. Proj Dis	(33,170)	-	-	-	-	-	-	-	-	-	-	-	(33,170)	-	-	-	(33,170)
E.0000042.001	MN/WBL/County Rd B Replacement-NSP	712,782	47,515	-	-	-	-	-	-	2,148	-	3,306	171	765,923	(5,626)	(14,849)	-	745,449
E.0000044.001	MN/STP/ECL Replace-Mplwd-NSP Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(5,940)	-	(5,940)
E.0000044.002	MN/STP/East County Line Tran Line	198,530	79,583	-	-	-	-	-	-	511	-	648	-	279,273	(1,159)	(279)	-	277,834
E.0000051.001	MN/Colby Lake Lateral Replace	9,027,511	1,869,701	-	694,392	39,626	438	-	(2,702)	10,315	6,342	14,645	67	11,660,334	(31,369)	(421,919)	(2,039,682) *	9,167,363
E.0000052.001	MN/Arden Hills/System H05 Replace	6,536,081	1,393,699	-	633,750	480	1,895	-	-	9,279	10,102	25,691	108	8,611,084	(45,180)	(361,901)	-	8,204,004
E.0010011.003	Progrommatic Main Replacement - Mains	11,750,417	2,500,973	-	578,479	14,614	270	-	-	28,307	23,816	69,146	134	14,966,157	(121,403)	(620,551)	-	14,224,202
E.0010011.004	Progrommatic Main Replacement - Services	2,377,508	565,368	(200)	111,043	-	1,848	-	-	2,199	2,018	7,417	315	3,067,516	(11,949)	(597,414)	-	2,458,153
E.0010011.005	NSPM Install 6" and 4" Dist. Valves	134,135	96,939	-	148,015	-	4,087	-	-	27,145	24,420	66,228	27	500,994	(117,820)	(25,130)	-	358,044
E.0010073.004	MN/STP/ECL Replace-Maplewood to NSP	26,262	805	-	-	-	-	-	-	-	-	-	-	27,067	-	(1,095)	-	25,972
	Grand Total	$ 35,468,285	$ 7,944,554	$ (200)	$ 2,645,053	$ 201,895	$ 11,246	$ -	$ (2,702)	$ 122,616	$ 97,887	$ 313,448	$ 1,531	$ 46,803,614	$ (535,483)	$ (753,486)	$ (2,039,682)	$ 43,474,963

*__Note__: Approximately 18.2% of the overall Colby Lake Lateral Replacement project consistitued a betterment, and is not eligible for GUIC cost recovery. The exact amount to be removed from our 2018 revenue requirement will be determined when final 2018 data is available, and will be reflected in our next update to our revenue requirement.

*__Note:__ Approximately 18.2% of the overall Colby Lake Lateral Replacement project consistitued a betterment, and is not eligible for GUIC cost recovery.

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

Xcel Energy		Information Request No.	50
Docket No.:	G002/M-18-692		
Response To:	MN Department of Commerce		
Requestor:	Dorothy Morrissey / Danielle Winner		
Date Received:	February 15, 2019		

<u>Question:</u>

Topic: Risk Assessments for GUIC Programs
Reference(s): Petition, Attachment D2(a), page 3; Petition, Attachment W, pages 7-8

In Xcel's 2019 GUIC Petition, Attachment D2(a) on page 3, Xcel shows a table of steel mains and services identified within the Optimain system as of August 2018.

A. Do the potential projects identified in this page 3 table represent all or a portion of the potential GUIC-eligible steel main/service projects in Minnesota? If only a portion are represented, what is the total number of potential projects in this program?

B. Xcel appears to report the same numbers in this page 3 table for GUIC filings in Dockets 16-891, 17-787, and 18-692, even though the project identification date changes. The Department would expect the project figures to change over time as higher risk projects are pursued and lower risk projects age into higher risk categories. Why does the Company report the same figures each year?

C. How many steel main/service projects has Xcel completed each year since the start of the GUIC Rider? Which risk categories did these projects fall into prior to and after completing the work? What was the final risk composition of all system projects at the end of each year (i.e., what did the page 3 table look like for each year)?

D. Please provide the same table that appears on page 3 for each GUIC TIMP and DIMP program (e.g., DIMP plastic mains, DIMP IP Assessments Line Replacement, etc.), reflecting the appropriate Project Risk Score Range for the relevant project, and reflecting the current state of Xcel's Minnesota system. Please include all potential projects in each category, or specify what percentage of all potential projects is represented in each table.

E. For each GUIC TIMP and DIMP program, please provide the number of projects completed each year since the start of the GUIC Rider, and the risk categories the completed projects fell into prior to and after completing the work. Please provide the total risk composition for all projects in each program for each year since the start of the GUIC Rider (i.e., a page 3 table for each program for each year since the start of the GUIC rider).

In Attachment W, pages 7-8, Xcel provides Figure 3 (Unit Costs for Poor Performing Main Replacement Projects) and Figure 4 (Unit Costs for Poor Performing Service Replacement Projects).

F. Please send excel spreadsheets of the 2017 raw data used to make these curves. Please also classify each observation according to appropriate 1-4 scale population-based consequence class. Please define the parameters of each consequence class.

G. Please send excel spreadsheets of the raw data for the unit costs for poor performing main and service replacement projects for years 2015 and 2016. Please also classify each observation according to appropriate 1-4 population-based consequence class. Please define the parameters of each consequence class.

Response:

A. The potential projects identified in the table on page 3 of Petition Attachment D2(a) represent all active pipe projects included in the Optimain DS risk software in Minnesota. The projects include both GUIC and non-GUIC projects and incorporate all other pipe materials. In the Optimain DS software, pipelines are broken into segments, referred to as projects. GUIC-identified projects may be completed on one or more Optimain DS projects. Please note that the table shown in page 3 of Attachment D2(a) was not accurate for 2018 and updated amounts are shown in Part B below.

As of October 2018, approximately 9,000 of the projects identified in the updated table provided in Part B of this response have a primary material type of steel, and would thus be subject to risk evaluation through Optimain DS under the GUIC "DIMP Poor Performing Mains and Services – Problematic Steel Project Risk."

B. In developing the response to this inquiry, it was discovered that updated information for the table on Petition Attachment D2(a), page 3 was inadvertently omitted. Tables showing final risk composition of all gas distribution system projects (all materials) are provided below for 2016, 2017 and 2018. The tables reflect updated versions of the same information presented in our last three GUIC filings.

2018 Gas Distribution System Risk Composition

Risk Category	Project Risk Scores Range	Number of Optimain Projects Identified as of October 2018	Percentage
High	Score ≥ 36	1,415	2.42%
Medium	24 ≤ Score < 36	663	1.13%
Low	1 ≤ Score < 24	12,519	21.37%
None	Score < 1	43,990	75.08%
Total	**All**	**58,587**	

2017 Gas Distribution System Risk Composition

Risk Category	Project Risk Scores Range	Number of Optimain Projects Identified as of December 2017	Percentage
High	Score ≥ 36	2,693	4.48%
Medium	24 ≤ Score < 36	665	1.11%
Low	1 ≤ Score < 24	12,547	20.89%
None	Score < 1	44,152	73.52%
Total	**All**	**60,057**	

2016 Gas Distribution System Risk Composition

Risk Category	Project Risk Scores Range	Number of Optimain Projects Identified as of December 2016	Percentage
High	Score ≥ 36	2,829	4.68%
Medium	24 ≤ Score < 36	654	1.08%
Low	1 ≤ Score < 24	12,600	20.86%
None	Score < 1	44,320	73.37%
Total	**All**	**60,403**	

C. The base material and risk score of completed projects was not tracked until the establishment of the Company's Quantitative Risk Assessment (QRA) methodology. The QRA methodology was filed in the January 2017 Supplement to our 2017 GUIC Rider Petition (Docket No. G002/M-16-891), which provided our initial metrics proposal.

The first table below reflects all completed GUIC main/service projects, independent of material, for 2015-2016. The second table reflects all completed steel main/service projects completed in 2017 and 2018 with their associated risk categories. The detailed information for 2017 is also available in Attachment D1(a) filed with our Petition. The final risk composition of all system projects at the end of each year is shown in the tables provided in Part B, above.

Year	Total GUIC Projects – All Materials
2015	40
2016	41

Year	Total GUIC Steel Main/Service Projects	High Risk	Medium Risk	Low Risk
2017	30	29	1	0
2018	57	56	1	0

D. The information and risk analysis methodology evaluating the current state of the Company's Minnesota system are unique to the DIMP Poor Performing Main and Service Program. The risk evaluation information found in the table on page 3 of Petition Attachment D2(a) for projects under consideration for renewal are researched and evaluated as part of the Company's Optimain DS risk model. Optimain DS is not used to assess other DIMP and TIMP programs. As a result, a similar view for other GUIC programs is not available, nor applicable.

The risk profiles for DIMP plastic mains, DIMP IP Line Assessments/ Replacements, for example, are metric related and developed through the Company's QRA methodology rather than through the Optimain DS risk model. The methodologies are identified and supplied in Petition DIMP Attachments D2(a)/D2(b) and TIMP Attachment C2.

E. The number of projects completed each year for each GUIC TIMP and DIMP program is provided in Attachment A to this response. The risk score for each project was not tracked until the establishment of the Company's QRA methodology. As such, risk categories are only provided for those projects completed in 2017 and 2018. Inherent to the QRA methodology established for each GUIC program, once a project is completed it would be expected to be classified as low risk. For example, in the DIMP Sewer & Gas Line Conflict risk assessment methodology provided on page 15 of Petition Attachment D2(a), an area that has been previously inspected would receive a likelihood of failure score of 0.5 and would be classified as "low risk."

Similar to the Company's response to Part D of this request, the Company has evaluated and defined risk for all programs other than DIMP Poor Performing Mains and Services using the QRA methodology. The identification of relative risk in those programs has been provided in DIMP Attachments D2(a)/D2(b) and TIMP Attachment C2 filed with our Petition.

F. Please reference Attachment B to this response for the 2017 raw data utilized to make the curves in Petition Attachment W, pages 7-8, Figure 3 (Unit Costs for Poor Performing Main Replacement Projects) and Figure 4 (Unit Costs for Poor Performing Service Replacement Projects). Attachment B is provided in live Excel spreadsheet format. The Company is unable to classify these observations according to the 1-4 scale population-based consequence class. This risk evaluation factor is only applicable for projects considered under the DIMP IP Line Assessment/Replacement and TIMP Assessment/Replacement programs. Class locations are defined in Code of Federal Regulations Part 192.5.

G. Please reference Attachment C to this response for the raw data for the unit costs for poor performing main and service replacement projects for years 2015 and 2016. Attachment C is provided in live Excel spreadsheet format. As referenced in Part F of the response, the Company is unable to classify these observations according to the 1-4 scale population-based consequence class since this risk evaluation factor is only applicable for projects considered under the DIMP IP Line Assessment/Replacement and TIMP Assessment/Replacement programs.

Preparer:	Steve Martz
Title:	Director
Department:	Gas Engineering
Telephone:	303-571-3249
Date:	February 26, 2019

Northern States Power Company

Docket No. G002/M-18-692
DOC Information Request No. 50
Attachment A - Page 1 of 1

TIMP and DIMP Projects Completed 2015-2018

DIMP Programs	Project Counts	
	2015	2016
Poor Performing Main and Service Replacements	40	41
Distribution Valve Replacements	92	114
Sewer Inspections	20,609	18,375
IP Line Assessments/Replacements	0	3
Federal Code Mitigation	0	506
TIMP Programs	**Project Counts**	
	2015	**2016**
ASV/RCV	1	4
East Metro	1	1
Transmission Assessments/Replacements	4	6
MAOP Validation/Remediation	0	0

DIMP Programs	Project Counts							
	2017				2018			
	Low	Medium	High	Total	Low	Medium	High	Total
Poor Performing Main and Service Replacements	1	9	31	41	-	4	77	81
Distribution Valve Replacements	16	2	8	26	6	3	14	23
Sewer Inspections	-	-	22,154	22,154	-	-	15,789	15,789
IP Line Assessments/Replacements	-	1	2	3	-	2	2	4
TIMP Programs	**Project Counts**							
	2017				**2018**			
	Low	**Medium**	**High**	**Total**	**Low**	**Medium**	**High**	**Total**
ASV/RCV	-	6	1	7	-	3	-	3
Transmission Assessments/Replacements	-	3	-	3	-	1	2	3
MAOP Validation/Remediation	-	-	2	2	-	-	3	3

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. G002/M-18-692

Dated this 4th day of March 2019

/s/Sharon Ferguson

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_18-692_M-18-692
Alison C	Archer	aarcher@misoenergy.org	MISO	2985 Ames Crossing Rd Eagan, MN 55121	Electronic Service	No	OFF_SL_18-692_M-18-692
Gail	Baranko	gail.baranko@xcelenergy.com	Xcel Energy	414 Nicollet Mall7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_18-692_M-18-692
John	Coffman	john@johncoffman.net	AARP	871 Tuxedo Blvd. St, Louis, MO 63119-2044	Electronic Service	No	OFF_SL_18-692_M-18-692
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1800 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_18-692_M-18-692
Corey	Conover	corey.conover@minneapolismn.gov	Minneapolis City Attorney	350 S. Fifth Street City Hall, Room 210 Minneapolis, MN 554022453	Electronic Service	No	OFF_SL_18-692_M-18-692
George	Crocker	gwillc@nawo.org	North American Water Office	PO Box 174 Lake Elmo, MN 55042	Electronic Service	No	OFF_SL_18-692_M-18-692
Ian	Dobson	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	Yes	OFF_SL_18-692_M-18-692
Rebecca	Eilers	rebecca.d.eilers@xcelenergy.com	Xcel Energy	414 Nicollet Mall - 401 7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_18-692_M-18-692
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_18-692_M-18-692

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Edward	Garvey	edward.garvey@AESLconsulting.com	AESL Consulting	32 Lawton St Saint Paul, MN 55102-2617	Electronic Service	No	OFF_SL_18-692_M-18-692
Edward	Garvey	garveyed@aol.com	Residence	32 Lawton St Saint Paul, MN 55102	Electronic Service	No	OFF_SL_18-692_M-18-692
Todd J.	Guerrero	todd.guerrero@kutakrock.com	Kutak Rock LLP	Suite 1750 220 South Sixth Street Minneapolis, MN 554021425	Electronic Service	No	OFF_SL_18-692_M-18-692
Kimberly	Hellwig	kimberly.hellwig@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_18-692_M-18-692
Annete	Henkel	mui@mnutilityinvestors.org	Minnesota Utility Investors	413 Wacouta Street #230 St.Paul, MN 55101	Electronic Service	No	OFF_SL_18-692_M-18-692
Michael	Hoppe	il23@mtn.org	Local Union 23, I.B.E.W.	932 Payne Avenue St. Paul, MN 55130	Electronic Service	No	OFF_SL_18-692_M-18-692
Linda	Jensen	linda.s.jensen@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota Street St. Paul, MN 551012134	Electronic Service	No	OFF_SL_18-692_M-18-692
Richard	Johnson	Rick.Johnson@lawmoss.com	Moss & Barnett	150 S. 5th Street Suite 1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_18-692_M-18-692
Sarah	Johnson Phillips	sarah.phillips@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_18-692_M-18-692
Michael	Krikava	mkrikava@briggs.com	Briggs And Morgan, P.A.	2200 IDS Center 80 S 8th St Minneapolis, MN 55402	Electronic Service	No	OFF_SL_18-692_M-18-692

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Peder	Larson	plarson@larkinhoffman.com	Larkin Hoffman Daly & Lindgren, Ltd.	8300 Norman Center Drive Suite 1000 Bloomington, MN 55437	Electronic Service	No	OFF_SL_18-692_M-18-692
Eric	Lipman	eric.lipman@state.mn.us	Office of Administrative Hearings	PO Box 64620 St. Paul, MN 551640620	Electronic Service	No	OFF_SL_18-692_M-18-692
Ryan	Long	ryan.j.long@xcelenergy.com	Xcel Energy	414 Nicollet Mall 401 8th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_18-692_M-18-692
Peter	Madsen	peter.madsen@ag.state.mn.us	Office of the Attorney General-DOC	Bremer Tower, Suite 1800 445 Minnesota Street St. Paul, Minnesota 55101	Electronic Service	No	OFF_SL_18-692_M-18-692
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	OFF_SL_18-692_M-18-692
Mary	Martinka	mary.a.martinka@xcelenergy.com	Xcel Energy Inc	414 Nicollet Mall 7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_18-692_M-18-692
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_18-692_M-18-692
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_18-692_M-18-692
David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency	220 South Sixth Street Suite 1300 Minneapolis, Minnesota 55402	Electronic Service	No	OFF_SL_18-692_M-18-692
Amanda	Rome	amanda.rome@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 5 Minneapoli, MN 55401	Electronic Service	No	OFF_SL_18-692_M-18-692

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Richard	Savelkoul	rsavelkoul@martinsquires.com	Martin & Squires, P.A.	332 Minnesota Street Ste W2750 St. Paul, MN 55101	Electronic Service	No	OFF_SL_18-692_M-18-692
James M.	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	470 U.S. Bank Plaza 200 South Sixth Street Minneapolis, MN 55402	Electronic Service	No	OFF_SL_18-692_M-18-692
Lynnette	Sweet	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_18-692_M-18-692
Daniel P	Wolf	dan.wolf@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_18-692_M-18-692