COMMERCE DEPARTMENT

September 16, 2020

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-19-664

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 2019, Revenue Requirements for 2020, and Revised Adjustment Factors (Petition).

The Petition was filed on October 25, 2019 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/ja
Attachments

COMMERCE DEPARTMENT

Before the Minnesota Public Utilities Commission

Comments of the Minnesota Department of Commerce Division of Energy Resources

Docket No. G002/M-19-664

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]

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]

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[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.

[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.

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] On August 12, 2019, the Commission issued its Order Authorizing Rider Recovery and Setting Reporting Requirements. The Commission authorized a 12-month recovery period effective the month following the Order's date.

On November 1, 2018, in Docket No. G002/M-18-692 (Docket 18-692), Xcel requested approval of a 2019 GUIC Rider to recover the 2019 revenue requirement and its prior year (2018) true up (2019 GUIC Rider). On January 9, 2020, the Commission issued its Order Authorizing Rider Recovery with Modifications. The Commission authorized a 12-month recovery period, effective March 1, 2020, as proposed by Xcel.

On October 25, 2019, Xcel filed this current Petition for approval of its revenue requirements for 2020, and its 2019 true up report (2020 GUIC Rider). On November 22, 2019, the Commission granted the Department's six-month extension request, and on May 12, 2020, the Commission granted the Department's second six-month extension request.

II. PETITION SUMMARY

A. PROPOSED RATE FACTORS

Xcel proposed to recover from ratepayers a total annual amount of $21.3 million, assign the 2020 GUIC Rider total revenue requirements to its various customer classes in the same manner as revenue responsibilities were apportioned in its most recent natural gas rate case,[7] consistent with the Commission's 2015-2019 GUIC Rider Orders. As proposed, the 2020 GUIC Rider's impact on the average residential customer's bill would be an approximate $2.74 charge per month.[8] To update these bill impacts and reflect that Xcel's natural gas customers tend to use more natural gas in the winter, the Department provides the following Tables, which show the bill impact by class both annually and based on Xcel's weather-normalized sales in December, 2019, which is the most recent information available:

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[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] Docket No. G002/GR-09-1153.

[8] Petition, p. 33. Xcel appears to estimate that the average residential customer consumes approximately 74 therms of gas per month. $2.74 = 73.78 therms * $0.037138 per therm.

Department Table 1. Annual Bill Impacts

Class	Annual Sales (Dkt)*	Actual Customers*	Use/Customer (Dkt)	Rate (therm)	Annual Bill Impact
Residential with Heating	38,021,281	428,483	88.73	$0.037138	$ 32.95
Commercial	22,256,761	35,182	632.61	$0.019301	$ 122.10
Industrial and Mining	3,069,408	137	22,336.50	$0.014657	$ 3,273.86
Small Interruptible	10,829,344	346	31,336.42	$0.011864	$ 3,717.75
Transportation	51,361,731	24	2,140,072.13	$0.003425	$ 73,297.47

*Source: G,E999/PR-20-4, Xcel's annual weather-normalized sales, Tabs 36, 37

Department Table 2. December Bill Impacts

Class	December Sales (Dkt)*	Actual Customers*	Use/Customer (Dkt)	Rate (therm)	December Bill Impact
Residential with Heating	6,461,703	430,767	15.00	$0.037138	$ 5.57
Commercial	3,782,369	35,374	106.93	$0.019301	$ 20.64
Industrial and Mining	365,370	137	2,658.85	$0.014657	$ 389.71
Small Interruptible	1,354,433	336	4,031.05	$0.011864	$ 478.24
Transportation	4,457,591	24	185,732.96	$0.003425	$ 6,361.35

*Source: G,E999/PR-20-4, Xcel's December weather-normalized sales, Tabs 36, 37

Further details of Xcel's proposed billing factors, presuming use of Xcel's sales forecast, for each customer class are provided on page 33 of Xcel's Petition (Xcel Table 7) and are compared to the current 2019 GUIC factors in Department Table 3 below:

Department Table 3. Xcel's Current (2019) and Proposed (2020) GUIC Rate Factors

GUIC Rider Charge per therm		
	2019 Factors Dkt 18-692	**2020 Proposed**
Residential	$0.036654	$0.037138
Commercial Firm	$0.019680	$0.019301
Commercial Demand Billed	$0.014813	$0.014657
Interruptible	$0.010632	$0.011864
Transportation	$0.001528	$0.003425

The Department notes that the 2020 proposed factors in the above table represent Xcel's calculations at the time of filing; in Xcel's compliance filing in this docket, these figures will be changed to reflect updated calculation inputs.

B. PROPOSED REVENUE REQUIREMENT

As noted above, Xcel Gas requested recovery of its $21.3 million proposed 2020 GUIC revenue requirement over a 12-month period through a rider rate effective March 1, 2021.[9] The proposed revenue requirement includes recovery of capital property taxes, current and deferred taxes, and book depreciation. Xcel calculated its requested $21.3 million revenue requirement using the Company's proposed return on equity (ROE) of 9.04 percent, the same ROE that the Commission has approved in Xcel's prior GUIC petitions.[10]

The proposed 2020 GUIC rider revenue requirement equates to approximately 13.4 percent of the $159.10 million total base rate revenues approved in Xcel Gas's previous general rate case (Docket No. G002/GR-09-1153).[11] For comparison purposes, the rate increase that Xcel requests in this proceeding is over $5 million more than Xcel requested in its prior rate case and nearly twice the amount that the Commission awarded to Xcel in that case.[12] Xcel estimates that the 2020 GUIC Rider request composes approximately 4.4 percent of the customers' total bill charges in 2020.

A summary of Xcel Gas's proposed 2020 revenue requirement (from Petition, page 29) is included below:

[9] Petition, pp. 1, 29. The Company's proposed $21.3 million revenue requirement for 2020 assumes no GUIC tracker carryover balance from prior years.
[10] Petition, p. 36.
[11] Petition, p.31. 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 L of the Petition.
[12] Xcel requested an increase of $16.22 million and the Commission granted $7.291 million.

Department Table 4. Xcel Gas's Proposed 2020 Gas Utility Infrastructure Revenue Requirements

2019-2020 GUIC Rider Revenue Requirement ($ Millions)

	2019 Current Forecast	2020 Forecast
Capital-Related Revenue Requirement		
TIMP	$8.7	$10.5
DIMP	$9.6	$12.0
Total	$18.3	$22.5
O&M Expenses		
TIMP	$2.4	$1.5
DIMP	$2.7	$0.6
Total	$5.1	$2.1
5-Year Amortization of Deferred Costs (Year 5 in 2019)		
TIMP	$0.8	$0.0
DIMP	$3.7	$0.0
Total	$4.6	$0.0
GUIC Retirement Revenue Credits	$(0.8)	$(0.7)
O&M Recovery in Base Rates	$(0.5)	$(0.5)
Regulatory Treatment	$(2.1)	$(2.1)
Revenue Requirement Subtotal	$24.7	$21.3
True-up Carryover	$(0.9)	$0.0
Total GUIC Rider Revenue Requirement	**$23.7**	**$21.3**

Xcel Gas's requested GUIC revenue requirement reflects cost recovery of its ongoing Transmission Integrity Management Program (TIMP) and Distribution Integrity Management Program (DIMP) project initiatives. There are no new TIMP or DIMP project initiatives for 2020.

The 2020 revenue requirement included offsets to the GUIC Rider (labeled "GUIC Retirement Revenue Credits," "O&M Recovery in Base Rates," and "Regulatory Treatment"), as well as a carryover from the 2019 tracker balance ("True-up Carryover"). However, the 2020 revenue requirement does not include two previously approved deferred cost requests that were included in 2019, as 2019 marked the final year for the amortized recovery of those deferrals.[13] The Department discusses these 2020 GUIC cost/adjustment categories in the following sections.

1. *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.[14] 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.[15]

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[13] Petition, p. 29. Deferred costs from 2019 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. For more discussion, see page 5 of the Department's March 4, 2019 Comments in 18-692.

[14] 49 C.F.R. § 192, Subpart O.

[15] Petition Attachment C, p. 1.

In general, Xcel's TIMP project activity involves assessing and improving the safety of its gas transmission system, which consists of approximately 75 miles of pipeline in the state of Minnesota.[16] 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**, a capital-intensive program that strives to meet the requirement to have traceable, verifiable, and complete (TVC) records of a pipeline's MAOP and targets repairs or replacement efforts needed on transmission pipelines that have been assessed for asset health and condition in prior years.

2. 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.[17] A DIMP is intended to help gas utilities identify, prioritize, and evaluate risks, implement measures to address risk, and validate the integrity of their gas distribution system.

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; and
- **Distribution Pipeline Inspection and Replacement**, determine the health and condition of medium-sized distribution pipelines.

3. OFFSETS TO GUIC RIDER REVENUE REQUIREMENTS

Per Minn. Stat. § 216B.1635, the GUIC Rider is to recover only costs incremental to those reflected in base rates. 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.

Two of the adjustments shown in Department Table 4 above , $(0.7) million and $(0.5) million, reflect recoveries included in base rates. The estimated $(0.7) 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. Xcel will update this impact on the rider revenue requirement

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[16] Petition, p. 7.
[17] 49 C.F.R. § 192, Subpart P.

once actual 2019 and 2020 retirements are known.[18] Next, the $(0.5) million operating and maintenance (O&M) adjustment reflects transmission integrity management expense levels that were built into Xcel Gas's base rates.[19] By recognizing the revenue requirement of these cost recoveries embedded in the Company's existing base rates, by adjusting them out from the gross GUIC project work revenue requirements, an incremental revenue requirement for the rider is established.

Department Table 4 also shows an adjustment for $(2.1) million for "Regulatory Treatment." This offset reflects the impact of prior Commission decisions to modify certain cost recoveries through the GUIC rider mechanism. For example, the Commission decided in Xcel's prior two GUIC petitions to remove from rider recovery the internal capitalized overhead costs and also deny recovery of certain project cost overruns.[20] This offset estimate is subject to update once year-end asset retirements[21] for 2019 and 2020 are known and for any directives made herein.

4. PRIOR YEAR CARRYOVER BALANCE

The prior year (2019) rider rate and recovery is ongoing and designed to be in effect through February 2021, with the objective to resolve to no carryover balance. At the time of the filing, the prior period carryover balance was projected to be zero for purposes of the 2020 GUIC rate. This amount will be updated to the actual 2019 rider carryover balance once that value is known and final 2020 rider rates are calculated.

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 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

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[18] Petition, pp. 26-27.
[19] These base rate inclusions of $480,000 (rounded to $0.5 million) are summarized in Xcel's petition in Docket No. G002/M-12-248, pp. 6-7 and 9-10.
[20] Docket Nos. G002/M-17-787 and G002/M-18-692. Although not provided in these comments, further breakdown of this sum is available in Xcel Gas's trade secret response to information request DOC IR No. 2, the MS Excel Attachment - GUIC Rider Revenue Requirements Model, Tab "RIS - Reg Treatment."
[21] Petition, pp. 26-27.

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 to mean 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;
- 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 only 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

[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
[26] *Id.*, Subd. 4.
[27] *Id.,* Subd. 5.

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 Petition) along with identification of specific projects in Attachments such as C, C1, C2, D, D1, D2(a)-D2(b).

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

In conjunction with GUIC project activity, Xcel may carry out additional work not otherwise eligible under the GUIC statute. Consistent with the Commission Order in Docket No. G002/M-18-692, the Company committed to remove from its final revenue requirement actual cost amounts for any additional low-risk work done along with its GUIC-eligible projects.[32] The Department appreciates Xcel's commitment to do so.

C. COMMISSION FILING REQUIREMENTS

In various prior GUIC filings, the Commission has directed Xcel to include or refine certain information in subsequent filings. The cumulative petitions' requirements are summarized by Xcel in a matrix included as Attachment A to this petition.[33] In our comments, the Department limits its discussion of these requirements to those that have not been reasonably satisfied.

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[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. 5, Requirement 6.
[32] See Petition Footnote 2, p. 2. In the Matter Ordering paragraph 7
[33] See DOC Attachment A for Xcel's amending of Xcel Attachment A matrix in its response to DOC IR No. 7. Because this instant petition predates the issuance of the Commission's order in the latest GUIC petition, Docket No. G002/M-18-692, the Company's attached response includes references pertinent to the Commission's decisions in that docket in a similar matrix format.

D. TIMING OF 2020 GUIC RIDER FACTOR IMPLEMENTATION

The Company proposed to implement the 2020 GUIC Rider rate starting March 1, 2021, to recover costs over a 12-month period. The proposed implementation date and recovery period is consistent with the timing of the 2019 GUIC rate, thus allows for more stable factors and eliminates the need for the proration of ADIT. The Department is supportive of Xcel's proposal.

The Department notes that, should the Company file a general rate case petition with a 2021 proposed test year, though the general rate case may roll-in the in-service GUIC Rider projects into its proposed 2021 test year, the 2020 GUIC Rider rates would still need to be in effect because it is recovering prior 2020 operating year's costs. Further, the Commission may hear and decide this petition in 2020, well in advance of proposed rate implementation. Since the Company will await certain 2020 actual data to update its final revenue requirement and rider rate calculations, the Department requests that Xcel file a preliminary revenue requirements and rider factor schedules within 10 days of the Commission's order, followed by a final compliance filing, prior to rate factor implementation, once any actual 2020 input data is known. Since the GUIC petition has some complexity, a preliminary filing will provide parties the opportunity to resolve any discrepancies prior to issuance of final compliance and rate factor implementation.

E. ISSUES IDENTIFIED

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

1. *Sales Forecast*
2. *TIMP – Programmatic Replacement And MAOP Remediation*
3. *Internal Capitalized Costs*
4. *Risk Assessment and Performance Metrics*

IV. DEPARTMENT ISSUES

A. SALES FORECAST

In Xcel's Petition, the Company calculated the final rate factors by dividing each customer class's proposed revenue requirement by its projected gas consumption. The projected gas consumption for each class is based on a sales forecast shown in Attachment Q.

Similarly, in Xcel's petitions for 2018 and 2019 GUIC Riders, the Company calculated final rate factors using a gas sales forecast. In those proceedings, however, the Department disagreed with Xcel's assumptions about the projected Interdepartmental Transport usage. Specifically, the Company assumed that it would experience reductions in natural gas volumes for this class due to increases in new wind projects, which would in turn decrease natural gas generation. The Department did not support Xcel's approach of using generalized speculation in the forecast; while such speculation may be beneficial in the Company's internal settings, it is not an appropriate methodology for calculating rates. In both years, the Department instead recommended that the Company base factors on the most recent 12 months of actual sales data. In both years, the Commission supported the Department's recommendation.

The Department notes that the Company bases its current use of forecasted values on the Commission's 2017 GUIC Order Point, as shown in the Company's Compliance Matrix found in Attachment A to the Petition. This Order Point reads:

> The Commission approves a revised sales forecast based on the company's regression model results before monthly sales and demand-side management (DSM) adjustments as set forth by the Company in Attachment F of its reply comments for the 2017 GUIC rider.

At the time of Xcel's filing of the instant Petition, the Commission's 2019 GUIC Order had not yet been released. However, the Commission's 2018 GUIC Rider Order was available, and required the Company to instead use the most recent actual sales data. The Department recommends that the Company update its compliance matrix with the most recent rate factor calculation methodology, and provide updated sales figures and rate factors in Reply Comments.

A. TIMP – PROGRAMMATIC REPLACEMENT AND MAOP REMEDIATION

In Xcel's two most recent GUIC rider petitions (Docket Nos. G002/M-17-787 and M-18-692), the Commission limited the return on this TIMP project to the Company's weighted cost of debt. The Department's analysis concludes and recommends the same action in this petition.

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.[34]

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,[35] and as result, on May 7, 2012, PHMSA issued an Advisory Bulletin to remind operators of gas and hazardous liquid pipeline

[34] DOC Attachment B, p. 3 (MAOP 192.619 letter from PHMSA).
[35] https://www.ntsb.gov/safety/safety-recs/recletters/P-10-001.pdf

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.[36]

On October 1, 2019, PHMSA published final rules, effective July 1, 2020, revising certain Federal Pipeline Safety Regulations (PSR) to address congressional mandates, National Transportation Safety Board (NTSB) recommendations, with the consideration of public input. Rule revisions relevant to MAOP validation were among those adopted. PHMSA took steps to assure certain finalized provisions were not retroactive. Below is the Department's summary of rules relevant to MAOP records:

> For steel transmission pipelines installed prior to July 2, 2020, if operators have records documenting,
>
> - (1) tests, inspections and material properties applicable at the time the pipe was manufactured [49 CFR 192.67(b)],
> - (2) pipe design and the determination of design pressure [49 CFR 192.127(b)], and
> - (3) the manufacturing standard and pressure rating for components used,
>
> operators must retain such records for the life of the pipeline [49 CFR 192.205(b)];
>
> however, if an operator does not have these records which are necessary to establish the MAOP, then the operator may be subject to MAOP reconfirmation requirement, i.e., 49 CFR 192.624 [49 CFR 192.205(c)]
>
> The MAOP reconfirmation of steel transmission pipelines is required if certain conditions are met, which include either (1) the pipeline's pressure test records are not traceable, verifiable and complete, and the pipeline is located in a more densely[37] populated area, or (2) the pipeline's MAOP was grandfathered, is in excess of 30 percent of specified minimum yield strength (SMYS), and the pipeline is located in a moderate-to-densely[38] populated area, or near prominent roadways. [49 CFR 19.624]
>
> The MAOP reconfirmation rule specifies six acceptable methods and permits operators to complete the required actions over the next 15 years, until July 2, 2035. These methods include: pressure test, pressure reduction (two methods), engineering critical assessment (ECA) such as data from an ILI, pipe replacement, or a supported alternative technology (such as guided wave ultrasonic testing) [49 CFR 192.624].

Xcel's MAOP Project initiative focuses on remediating data gap findings in order to ensure that the pipeline's MAOP can be supported by records.

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[36] https://www.govinfo.gov/content/pkg/FR-2012-05-07/pdf/2012-10866.pdf
[37] High consequence area, Class 3 and 4 locations as defined in 49 CFR 192.5 , as well as moderate consequence area
[38] Ibid. as well as moderate consequence area as defined in 49 CFR 191.3.

As stated in prior GUIC petitions, the Department understands that MAOP record retention and substantiation has been a requirement of pipeline operators since 1970[39]; 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 the pipeline records to establish MAOP levels, prior to PHMSA's recent rule revisions, were not required to be supportable or complete is not reasonable. For convenience, inserted below is the 1970 version of pipeline regulation language on pipeline tests:

> § 192.517 Records.
> Each operator shall make, and retain for the useful life of the pipeline, a record of each test performed under §§ 192.505 and 192.507. The record must contain at least the following information:
>
> > (a) The operator's name, the name of the operator's employee responsible for making the test, and the name of any test company used.
> > (b) Test medium used.
> > (c) Test pressure.
> > (d) Test duration.
> > (e) Pressure recording charts, or other record of pressure readings.
> > (f) Elevation variations, whenever significant for the particular test.
> > (g) Leaks and failures noted and their disposition.

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 reaffirm its prior decisions and 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[40] 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.

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[39] 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, including pressure testing.

[40] 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.

B. INTERNAL CAPITALIZED COSTS

The Commission has generally not allowed recovery of internal capitalized costs outside of rate cases in order to avoid double-recovery of costs. This includes Xcel Gas's GUIC Rider; the Commission denied recovery of certain internal capitalized costs in both the 2018 and 2019 GUIC Riders.

The Department discussed this issue at length in its Comments in both of those dockets,[41] noting that 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. The Department further cited the Commission's reasoning and conclusions regarding internal capitalized costs from a prior Order, including the following quotes:

> 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.[42]
>
> 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.[43]

The Department continues to conclude that it is inappropriate for Xcel to recover internal capitalized costs outside of a rate case. Consistent with the Commission's actions and the Department's recommendations from the 2018 and 2019 GUIC Riders, the Department recommends that the Commission deny recovery of Overheads, Transportation, and Other internal capitalized costs.

C. RISK ASSESSMENT AND PERFORMANCE METRICS

The Commission uses risk assessment and performance metrics tools to help determine the reasonableness of GUIC investments. Risk assessment is prospective, so this tool can be used to help the Commission evaluate specific projects that are expected to be undertaken in the upcoming year. Performance metrics are retrospective, so this tool can help the Commission determine how reasonable Xcel Gas's cost estimates were after projects are completed.

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[41] Department's March 4, 2019 Comments in Docket No. G002/M-18-692, pp. 24-28, and Department's July 3, 2018 Reply Comments in Docket No. G002/M-17-787, pp. 22-26.
[42] 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.
[43] 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.

In Xcel's instant filing, the risk assessment tool is applied to projected 2020 projects and can be found in Attachments C2, D2(a), and D2(b) of the Company's Petition. The Department reviewed the risk assessment reporting, and concludes that the Company's risk assessment process appears to be reasonable.

Xcel did not provide performance metrics evaluating completed projects, as it has in prior years, but instead included a discussion of performance metrics. The Department notes that this is likely an acceptable alternative, since the Commission has not approved specific performance metrics as of the time of these Comments, but instead has only directed parties to work towards consensus.

The Department provided an in-depth analysis of the Company's proposed performance metrics in its comments concerning the 2018 GUIC Rider.[44] In those comments, the Department determined that the Company's performance metrics did not adequately evaluate each of the GUIC programs. The Department recommended that the Commission should require, at minimum, *at least* one cost performance metric *and* one effectiveness performance metric for each TIMP and DIMP program in the relevant year. The Department also noted that metrics should be specific enough to give the Commission meaningful information about the specific program being evaluated.

The Department continues to have concerns that the currently proposed metrics do not adequately provide meaningful cost and effectiveness information for each TIMP and DIMP program. However, Xcel responded thoughtfully to the Department's critiques concerning performance metrics in both the 2018 and 2019 GUIC Rider proceedings. Xcel also met with the Department, Commission staff, the Minnesota Office of Pipeline Safety, and the Office of Attorney General on multiple occasions to fulfill the Commission's directive to work with stakeholders. As a result of these meetings, the Department was able to provide additional feedback, some of which Xcel incorporated into the performance metrics. In the instant Petition, Xcel states that the Company intends to request informal comments from parties and again schedule a meeting with stakeholders. Given Xcel's ongoing efforts to address the Department's concerns, the Department is reassured that the Company will continue to refine performance metrics reporting as it is able to. Therefore, the Department is no longer opposed to the metrics currently proposed by the Company.

V. DEPARTMENT CONCLUSIONS AND RECOMMENDATIONS

The Department recommends that the Commission approve the Company's petition with the following modifications:

- Require Xcel to use the most recent 12 months of actual natural gas sales to calculate the final GUIC Rider rates;
- Allow Xcel to update the base rate recovery offset inputs to the 2020 rider revenue requirement once actual 2019 and 2020 retirements are known, and direct Xcel to include the corresponding support schedules that list the type of cost (i.e., property taxes, depreciation, rate base, etc.) and its corresponding offset amount;

[44] Department's March 4, 2019 Comments in Docket No. G002/M-18-692, pp. 28-48.

- 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 GUIC internal capital costs for Overheads, Other, and Transportation, to the extent these costs are not removed elsewhere;
- Direct Xcel to provide electronic files with formulae intact, of the revenue requirement and corresponding rate factor schedules, based upon the Commission decisions herein, in any preliminary rate (within 10 days of Commission Order) and final rate compliance filings.

/ja

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

Xcel Energy		Information Request No. 7
Docket No.:	G002/M-19-664	
Response To:	Department of Commerce	**Supplement**
Requestor:	Dorothy Morrissey, Danielle Winner	
Date Received:	August 18, 2020	

Question:

Topic: Commission Order issued January 9, 2020, in Docket 18-692

Reference(s): Petition, Attachment A; and Order Points in Dkt G002/M-18-692

Request:

Refer to each of the Order Points, 3 through 16, from the January 9, 2020, Commission Order in Docket No. G002/M-18-692. Although this petition filing predates the issuance of this Order,

(a) please identify each of these Order Points that are continued and carried out in this current petition, and cite the relevant section/schedules within this filing; and

(b) please identify each of these Order Points that are not reflected in this petition, and state whether or not the Company intends to adopt and reflect that decision/directive in this current petition.

Response:

(a) The table below lists the Order Points incorporated into our 2020 GUIC Rider proposal as initially filed, along with references to where they are discussed or shown in the Petition.

Order Point	**Reference**
3. Xcel shall not apply prorated accumulated deferred income tax (ADIT) to rate base when it is not required by the Internal Revenue Service for normalization purposes.	Petition, Section VII.B.

Order Point	Reference
6. The Commission denies Xcel's request for a carrying charge in the GUIC tracker account.	Request does not include carrying charge.
7. Xcel shall remove and exclude from the GUIC rider costs related to low-risk infrastructure replacement that are not mandated by government regulations or public-work requirements.	Petition, Introduction
8. The return on the capital costs incurred to remediate the system's MAOP data gaps shall be limited to Xcel's weighted long-term cost of debt.	Adjustment included in revenue requirement calculations in original proposal, reflected in regulatory treatment line of Attachments N and O.
9. Xcel shall remove the costs of Overhead, Transportation, and Other, totaling $8,157,695, from the GUIC rider.	Adjustment included in revenue requirement calculations in original proposal, reflected in regulatory treatment line of Attachments N and O.
10. The Commission approves the following cost of capital for Xcel's 2019 GUIC Rider: **Capital Structure Cost Weighted Cost** Long-Term Debt 45.81% 4.75% 2.18% Short-Term Debt 1.69% 4.31% 0.07% Common Equity 52.50% **9.04%** 4.75% **Rate of Return 7.00%**	Introduction, Attachment K
11. Xcel shall exclude from its 2019 and future GUIC rider revenue requirements all costs related to emergency sewer-conflict work. Accordingly, Xcel shall adjust its 2019 GUIC rider revenue requirement to remove (1) $50,000 for these costs applicable to 2019, and (2) $371,364 for costs that were erroneously included in the rider in previous years.	Adjustment included in revenue requirement calculations, reflected in regulatory treatment line of Attachments N and O.
13. Xcel is permitted to recover $900,000 in DIMP-related cost overruns.	Costs are reflected in our DIMP revenue requirements.
14. Xcel shall continue to improve its risk assessment reporting in future GUIC filings, with the goal of providing better explanations of the Company's assets.	Petition, Section VI.A.3
15. Xcel shall provide consequence class information for both plastic and steel mains and services in future GUIC filings.	Consequence class information for mains and services was included. Petition, Section VI.A.3 and Attachments C, C2, D, and D2.
16. Xcel shall develop full risk-assessment profiles for the TIMP Transmission Pipeline Assessment program and the TIMP Programmatic/MAOP Remediation program.	Full risk-assessments profiles were included for the TIMP programs. Petition, Section VI.A.3 and Attachments C and C2

(b) The table below lists Order Points not yet incorporated into our 2020 GUIC Rider request. For each, we include an explanation as to why and/or when we will include it in our proposals.

Order Point	Notes
4. In the revenue-requirement schedules of its final compliance filing, Xcel shall show a breakdown of the ADIT balance to separately identify the excess ADIT balance, attributed to Pub. L. 115-97, a tax reform bill originally introduced in Congress as the 'Tax Cuts and Jobs Act,' that will be returned to ratepayers as well as the amortized amount of the excess ADIT being included in the GUIC revenue requirement.	Not included in our initial Petition. Requested breakdown will be shown in final compliance filing for this docket and in all future GUIC Rider filings.
5. Xcel shall use the most recent 12 months of actual natural gas sales to calculate the final GUIC rate.	Petition used forecast that aligned with the requested revenue recovery time period in order to match requested revenues with expected sales.
12. Xcel shall remove $1.97 million from the 2019 GUIC revenue requirement for forecasted TIMP-related costs that were ultimately not incurred.	Initial filing showed 2019 revenue requirement based on 6 months of actual data, and forecasted expenditures for remaining six months of the year. 2019 revenue requirement in our final compliance filing for our 2019 GUIC Rider (Docket No. G002/M-18-692) reflected our actual 2019 TIMP-related costs.

Supplement

To aid in the understanding of which of the Commission's Order points are included in our revenue requirement requests in this docket, and how they have been incorporated, the Company provides this supplement with some clarifications to part (a) of our original response above. We believe that no clarification is needed for part b of our response.

Order Point	Reference
3. Xcel shall not apply prorated accumulated deferred income tax (ADIT) to rate base when it is not required by the Internal Revenue Service for normalization purposes.	As our requested recovery period begins after the end of our requested test year, there is no need to prorate ADIT. This issue is discussed in Petition, Section VII.B.
6. The Commission denies Xcel's request for a carrying charge in the GUIC tracker account.	Request does not include carrying charge.
7. Xcel shall remove and exclude from the GUIC rider costs related to low-risk infrastructure replacement that are not mandated by government regulations or public-work requirements.	We removed all known low-risk infrastructure work from the 2018 through 2020 revenue requirements. This issue is discussed in Petition, Introduction.

Order Point	Reference
8. The return on the capital costs incurred to remediate the system's MAOP data gaps shall be limited to Xcel's weighted long-term cost of debt.	Our initial filing included the MAOP adjustment to limit the return on capital costs for MAOP to the Company's weighted long-term cost of debt for the 2018 and 2019 revenue requirements. Adjustment was reflected in the 2018 and 2019 regulatory treatment adjustments in Attachments N and O. We did not include the adjustment in our 2020 revenue requirement request. We will make the MAOP adjustment for 2020 in Reply Comments in Docket No. G002/M-19-664.
9. Xcel shall remove the costs of Overhead, Transportation, and Other, totaling $8,157,695, from the GUIC rider.	Our initial filing included adjustments to remove $8.2 million from the revenue requirement calculations for 2018, 2019, and 2020. This reflects the amount of overheads removed from 2018 and 2019 GUIC projects. Adjustment was reflected in the 2018 through 2020 regulatory treatment adjustments in Attachments N and O. We did not remove additional overheads for our 2020 GUIC projects. These are incremental costs that we argue are eligible for GUIC Rider recovery. We discussed this in our Petition, Section VI.C.2.
10. The Commission approves the following cost of capital for Xcel's 2019 GUIC Rider: **Capital Structure Cost Weighted Cost** Long-Term Debt 45.81% 4.75% 2.18% Short-Term Debt 1.69% 4.31% 0.07% Common Equity 52.50% **9.04%** 4.75% **Rate of Return 7.00%**	Calculation of revenue requirements for 2019 and 2020 are based on this approved capital structure. Calculation of final revenue requirements for 2018 were based on capital structure approved in that GUIC filing. Issue is discussed in Introduction, Attachment K.
11. Xcel shall exclude from its 2019 and future GUIC rider revenue requirements all costs related to emergency sewer-conflict work. Accordingly, Xcel shall adjust its 2019 GUIC rider revenue requirement to remove (1) $50,000 for these costs applicable to 2019, and (2) $371,364 for costs that were erroneously included in the rider in previous years.	Our initial filing included an adjustment to the 2019 revenue requirement to reflect the removal of emergency sewer-conflict work. Adjustment included in revenue requirement calculations for 2019, reflected in regulatory treatment line of Attachments N and O. No adjustment was necessary for 2020 as no emergency sewer work was included in our 2020 request, and impact of previous work was removed in 2019 revenue requirement.

Order Point	Reference
13. Xcel is permitted to recover $900,000 in DIMP-related cost overruns.	Costs are reflected in our DIMP revenue requirements.
14. Xcel shall continue to improve its risk assessment reporting in future GUIC filings, with the goal of providing better explanations of the Company's assets.	We discuss our continued improvement process for risk assessments in Petition, Section VI.A.3
15. Xcel shall provide consequence class information for both plastic and steel mains and services in future GUIC filings.	Consequence class information for mains and services was included. Issue is discussed in Petition, Section VI.A.3 and information is shown in Attachments C, C2, D, and D2.
16. Xcel shall develop full risk-assessment profiles for the TIMP Transmission Pipeline Assessment program and the TIMP Programmatic/MAOP Remediation program.	Full risk-assessments profiles were included for the TIMP programs. Issue is discussed in Petition, Section VI.A.3 and information is shown in Attachments C and C2.

Preparer: Brandon Kirschner
Title: Regulatory Policy Specialist
Department: NSPM Regulatory
Telephone: 612-215-5361
Date: August 28, 2020 **Supplemented: September 10, 2020**

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.

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

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:

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[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 **<u>the lowest of</u>** 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.

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-19-664

Dated this **16th** day of **September 2020**

/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_19-664_M-19-664
Alison C	Archer	aarcher@misoenergy.org	MISO	2985 Ames Crossing Rd Eagan, MN 55121	Electronic Service	No	OFF_SL_19-664_M-19-664
Gail	Baranko	gail.baranko@xcelenergy.com	Xcel Energy	414 Nicollet Mall7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_19-664_M-19-664
John	Coffman	john@johncoffman.net	AARP	871 Tuxedo Blvd. St, Louis, MO 63119-2044	Electronic Service	No	OFF_SL_19-664_M-19-664
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_19-664_M-19-664
George	Crocker	gwillc@nawo.org	North American Water Office	PO Box 174 Lake Elmo, MN 55042	Electronic Service	No	OFF_SL_19-664_M-19-664
Rebecca	Eilers	rebecca.d.eilers@xcelenergy.com	Xcel Energy	414 Nicollet Mall - 401 7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_19-664_M-19-664
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_19-664_M-19-664
Edward	Garvey	garveyed@aol.com	Residence	32 Lawton St Saint Paul, MN 55102	Electronic Service	No	OFF_SL_19-664_M-19-664
Edward	Garvey	edward.garvey@AESLconsulting.com	AESL Consulting	32 Lawton St Saint Paul, MN 55102-2617	Electronic Service	No	OFF_SL_19-664_M-19-664

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Todd J.	Guerrero	todd.guerrero@kutakrock.com	Kutak Rock LLP	Suite 1750 220 South Sixth Street Minneapolis, MN 554021425	Electronic Service	No	OFF_SL_19-664_M-19-664
Annete	Henkel	mui@mnutilityinvestors.org	Minnesota Utility Investors	413 Wacouta Street #230 St.Paul, MN 55101	Electronic Service	No	OFF_SL_19-664_M-19-664
Michael	Hoppe	il23@mtn.org	Local Union 23, I.B.E.W.	932 Payne Avenue St. Paul, MN 55130	Electronic Service	No	OFF_SL_19-664_M-19-664
Richard	Johnson	Rick.Johnson@lawmoss.com	Moss & Barnett	150 S. 5th Street Suite 1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-664_M-19-664
Sarah	Johnson Phillips	sarah.phillips@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-664_M-19-664
Peder	Larson	plarson@larkinhoffman.com	Larkin Hoffman Daly & Lindgren, Ltd.	8300 Norman Center Drive Suite 1000 Bloomington, MN 55437	Electronic Service	No	OFF_SL_19-664_M-19-664
Eric	Lipman	eric.lipman@state.mn.us	Office of Administrative Hearings	PO Box 64620 St. Paul, MN 551640620	Electronic Service	No	OFF_SL_19-664_M-19-664
Ryan	Long	ryan.j.long@xcelenergy.com	Xcel Energy	414 Nicollet Mall 401 8th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_19-664_M-19-664
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	OFF_SL_19-664_M-19-664
Mary	Martinka	mary.a.martinka@xcelenergy.com	Xcel Energy Inc	414 Nicollet Mall 7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_19-664_M-19-664

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_19-664_M-19-664
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-664_M-19-664
David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency	220 South Sixth Street Suite 1300 Minneapolis, Minnesota 55402	Electronic Service	No	OFF_SL_19-664_M-19-664
Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_19-664_M-19-664
Amanda	Rome	amanda.rome@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 5 Minneapoli, MN 55401	Electronic Service	No	OFF_SL_19-664_M-19-664
Richard	Savelkoul	rsavelkoul@martinsquires.com	Martin & Squires, P.A.	332 Minnesota Street Ste W2750 St. Paul, MN 55101	Electronic Service	No	OFF_SL_19-664_M-19-664
Will	Seuffert	Will.Seuffert@state.mn.us	Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul, MN 55101	Electronic Service	Yes	OFF_SL_19-664_M-19-664
James M	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	200 S 6th St Ste 470 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-664_M-19-664
Lynnette	Sweet	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_19-664_M-19-664