July 2, 2018 **PUBLIC DOCUMENT**

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101-2147

RE: **PUBLIC Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. G002/M-17-787

Dear Mr. Wolf:

Attached are the **PUBLIC** 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 2016, Revenue Requirements for 2017, and Revised Adjustment Factors (*Petition*).

The *Petition* was filed on November 1, 2017 and supplemented on March 27, 2018 and May 29, 2018 by:

> Amy Liberkowski
> Manager, Regulatory Analysis
> Xcel Energy
> 414 Nicollet Mall, 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 the Commission may have.

Sincerely,

/s/ DOROTHY MORRISSEY
Rates Analyst

/s/ DANIELLE WINNER
Rates Analyst

DM/DW/ja
Attachment

Before the Minnesota Public Utilities Commission

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

Docket No. G002/M-17-787

I. BACKGROUND

The Gas Utility Infrastructure Cost (GUIC) Recovery Rider was established under Minn. Stat. § 216B.1635.[1] It allows natural gas utilities expedited recovery of certain projects between rate cases. Eligible projects can constitute either replacement or modification of 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 or the Company), filed its inaugural GUIC recovery petition requesting approval to establish a rider (2015 GUIC Rider). This request was the first GUIC recovery proposal before the Minnesota Public Utilities Commission (Commission) for rate treatment under Minn. Stat. § 216B.1635. On January 27, 2015, the 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.

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

On November 1, 2016, in Docket No. G002/M-16-891 (Docket 16-891), Xcel filed its most recently approved GUIC Rider petition, in which the Company requested approval of a 2017 GUIC Rider and a true up of its revenue requirements for 2017 (2017 GUIC Rider). On February 8, 2018, the Commission issued its *Order Approving Rider with Modifications*, in which the Commission approved the 2017 GUIC Rider petition with the following modifications:

[1] The GUIC statute was established in 2005 and amended in 2014.

- Approved an overall rate of return of 7.02 percent for the 2017 GUIC Rider;
- Rejected the Company's proposed level of distribution-related software costs in the 2017 GUIC Rider, and directed Xcel to adjust distribution-related software costs included in rate base for recovery through the 2017 GUIC Rider to $444,543;
- Rejected all Quality Assurance/Quality Control (QA/QC) related costs included in the 2017 GUIC Rider since they represent duplicative services;
- Accepted Xcel's cost/revenue study based on 2015 actuals, which the Commission directed the Company to perform in its 2016 GUIC Rider Order;
- Directed Xcel to, in future GUIC filings, continue to discuss with parties, including the Minnesota Department of Commerce, Division of Energy Resources (Department) and the Office of Attorney General (OAG), proposed performance metrics and ongoing evaluation of reporting requirements;
- Directed Xcel to continue to provide, in future GUIC Filings, specific information about each individual GUIC project;
- Denied Xcel's proposed Accumulated Deferred Income Tax (ADIT) proration for the forecasted year in the instant petition, and instead determined that Xcel's 2017 GUIC Rider must not be effective prior to January 1, 2018;
- Approved Xcel's revised sales forecast based on the Company's regression model before adjustments to monthly sales and demand-side management, as presented in Attachment F of Xcel's Reply Comments filed March 13, 2017 in Docket 16-891;
- Approved sewer conflict inspection program costs, and directed Xcel to provide a cost-benefit analysis of these costs in future GUIC filings;
- Approved $2,249,926 in distribution valve replacement project costs to be recovered through the 2017 GUIC; and
- Required Xcel to recover 2017 revenue requirements over the 12 months following the effective date of the order.

Xcel implemented its 2017 GUIC Rider beginning March 1, 2018, which, per the Commission-directed 12 month recovery period, will be in effect through the end of February, 2019. The 2017 GUIC Rider is set to recover the Company's 2017 revenue requirement, in addition to any carryover balance from the 2016 GUIC Rider.

Since the 2017 GUIC Order was released after Xcel filed this instant *Petition*, Xcel filed a Supplement on March 27, 2018 (*Petition Supplement*) in the instant *Petition* to incorporate the Commission's directives from the 2017 GUIC Rider Order. The Department's Comments respond to Xcel's *Petition*, as updated by the *Petition Supplement*.

The first Section of these Comments provides background, Section II provides a summary of the Company's *Petition*, and Section III provides the Department's Analysis of the *Petition*. Section IV responds to Xcel's May 29, 2018 supplemental comments, filed per Commission Notice, regarding rate treatment considerations with respect to expense reductions related to Xcel Gas' annual depreciation study approved in Docket No. E,G002/D-17-581. Finally, in Section V, the Department provides a summary of conclusions and recommendations, and recommends approval, with modification, of the current 2018 GUIC Rider proposal.

II. SUMMARY OF PETITION

Xcel's forecasted 2018 revenue requirement is $24.36 million, compared to the prior year's actual 2017 revenue requirement of $20.1 million. [2] The 2018 figure from the *Petition Supplement* incorporates the newly enacted federal tax rate and the Commission's 2017 GUIC Rider Order in Docket 16-891.

In previous Orders, the Commission approved recovery of a number of projects under Minn. Stat. § 216B.1635 (GUIC Statute). Xcel's individual projects fall into two major categories: transmission- and distribution-integrity management programs (TIMP and DIMP, respectively). These programs carry out pipeline risk mitigation requirements of the U.S. Department of Transportation (USDOT), and are overseen by its agency, the Pipeline and Hazardous Materials Safety Administration (PHMSA).

In the TIMP category, the following initiatives are underway or planned:

- **Transmission pipeline assessments,** including in-line inspections (ILI), pressure tests, and direct assessment;
- **Automatic-shutoff and remote-controlled valve installation,** allows more expedient gas shutoff in an emergency; and
- **Programmatic Replacement/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.

In the DIMP category, Xcel has undertaken or plans to undertake the following projects to assess and improve the integrity of its distribution assets:

[2] The GUIC revenue requirement calculations are shown in the *Petition Supplement*, Attachments N and O.

- **Poor-performing main and service-line replacement,** identify high-risk pipeline segments and prioritizing their replacement in concert with city and county road maintenance;
- **Intermediate-pressure line assessments,** determine the health and condition of medium-sized distribution pipelines,
- **Distribution-valve replacements,** maintain Xcel's ability to isolate sections of the system in case of an emergency;
- **Federal Code Mitigation (FCM)**, conduct field work to maintain compliance with Federal Code; FCM identified project work is expected to be completed in 2018; and
- **Sewer and gas line conflict-remediation program,** identify and correct situations where natural gas lines intersect with sewer lines; this project is expected to be completed in 2019.

Table 1 presents the Company's estimated expenditures for each of these programs, divided between capital expenditures and operations and maintenance (O&M) expenditures:

Table 1: Estimated 2018 TIMP and DIMP Expenditures by Program in Xcel Gas's *Petition*

	Program	**Capital Expenditures ($ millions)**	**Operations and Maintenance ($ millions)**
TIMP	Transmission Pipeline Assessments	$0.30	$1.51
	ASVs and RCVs	$1.00	$0
	Programmatic Replacement and MAOP Remediation	$8.00	$0
	Total TIMP	$9.30	$1.51
DIMP	Poor Performing Main Replacements	$11.05	$0
	Poor Performing Service Replacements	$6.91	$0
	Intermediate Pressure (IP) Line Assessments	$19.82	$1.03
	Distribution Valve Replacement Project	$0.50	$0
	Sewer and Gas Line Conflict Investigation	$0	$2.31
	Federal Code Mitigation	$0	$0.20
	Total DIMP	$38.28	$3.54
Total, Initial	All Program Expenditures, *Petition*	$47.58	$5.05
Total, Final	**All Program Expenditures, *Petition Supplement***	**$45.53**	**$4.86**

All individual program expenditures reflect the Company's initial filing. The Company appears to have updated certain expenditures between the time of the initial filing and the time of the *Petition Supplement*, but did not specify which specific programs were affected by the changes. Table 2 presents the Company's proposed 2018 GUIC revenue requirement:

Table 2: Total Proposed 2018 GUIC Revenue Requirement, *Petition Supplement*

Project	**2018 Capital ($ Millions)**	**2018 O&M ($ Millions)**
Total TIMP Incremental Revenue Requirements	9.15	1.33
Total DIMP Incremental Revenue Requirements	6.25	3.53
O&M in Base Rates	n/a	(0.48)
5-Year Amortization of Deferred TIMP and DIMP Costs[3]	$4.55	
Pro-rated ADIT	0.03	
Total 2017 Revenue Requirements Combined before True Up	$24.36	
True-Up Carryover from 2017	$0	
GUIC Total 2018 Revenue Requirements	**$24.36**	

More precisely, Xcel's proposed 2018 GUIC revenue requirements total $24,359,177.

Xcel proposed an implementation date of August 1, 2018 for the proposed 2018 GUIC Rider, and proposed recovering its 2018 revenue requirement by the end of March, 2019.[4] Since the currently approved 2017 GUIC Rider will be in place until February 28, 2019, this proposal means that the Company would overlap two different GUIC Rider recovery year's factors from August 1, 2018 through February 28, 2019. Essentially, the overlapped, separately-tracked factors would be recovering different periods' revenue requirements: the 2017 GUIC Rider would recover the 2017 revenue requirement, and the 2018 GUIC Rider would recover the 2018 revenue requirement. The Department responds to this proposal in Section III.F.2 of these comments.

Xcel proposed to allocate the revenue requirements within the 2018 GUIC Rider to its various customer classes in the same manner as revenue responsibilities were apportioned in its most recent natural gas rate case,[5] consistent with the Commission's previous GUIC orders.[6]

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[3] In the 2015 GUIC Order, the Commission allowed the Company to amortize recovery of GUIC-eligible costs incurred prior to the 2014 GUIC Statute amendments. These amortized costs will be recovered through 2019.
[4] *Petition,* Page 7.
[5] Docket No. G002/GR-09-1153.
[6] 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.

However, for purposes of the GUIC Rider, the Company groups different classes together to create five class groups. Xcel then calculated rates for each class group by dividing the class group's revenue responsibility by the forecasted Minnesota sales for each class group over the course of the proposed 8-month recovery period, August 1, 2018 through February 28, 2019 (2018 GUIC Class Factors).[7]

The GUIC Rider rate is part of the Resource Adjustment line on customer bills.[8] The figures in Table 3, columns A – C, demonstrate that the increases in the proposed 2018 GUIC Class Factors over the 2017 GUIC Class Factors alone range between a 94.6% increase to a 125.1% increase in this charge.[9] However, since the Company is proposing to overlap the 2017 and 2018 GUIC Riders (that is, charge both the 2017 and 2018 rates simultaneously), ratepayers would actually experience a greater increase, as shown in Table 3, columns D and E. The subsequent Table 4 shows the average bill impacts for those rates.

Xcel's proposed GUIC Class Factor calculations assume that the current 2017 GUIC Class Factors would remain in effect for a 12-month period, or through February 28, 2019, and that the proposed 2018 GUIC Class Factors would become effective August 1, 2018, but recover the 2018 revenue requirements over a 8-month period, through February 28, 2019.

[7] In these Comments, the Department refers to the overall rider as the "GUIC Rider" and the rates charged to different customer groupings as "GUIC Class Factors."
[8] *Petition*, Page 37.
[9] The Department notes that though the 2018 GUIC revenue requirement ($24.36 million) is approximately 21 percent higher than the 2017 GUIC revenue requirement ($20.1 million), much of the comparative change in factor rates is due to Xcel's proposed use of a 8-month recovery period for the proposed 2018 revenue requirements.

Table 3: Percentage Increase from 2017 GUIC Class Factors to 2018 Class Factors, Overlapped 2017 and 2018 Class Factors

	2017 GUIC Rider (Docket 16-891)	**2018 GUIC Rider (Docket 17-787)**		**Overlapped 2017 and 2018 GUIC Riders**	
	A	B	C	D	E
	Approved 2017 Class Factors ($/therm)	Proposed [10] 2018 Class Factors ($/therm)	Percent Increase/ (Decrease) from 2017 Class Factors	Proposed Overlapping of 2017 and 2018 Class Factors ($/therm)	Percent Increase/ (Decrease) from 2017 Class Factors
Residential	0.027634	0.053784	94.6%	0.081419	194.6%
Commercial Firm	0.015080	0.030490	102.2%	0.045569	202.2%
Commercial Demand	0.011332	0.025143	121.9%	0.036475	221.9%
Interruptible	0.008114	0.018265	125.1%	0.026379	225.1%
Transport	0.003276	0.006870	109.0%	0.010157	209.0%

[10] *Petition Supplement*, Attachment Q

Table 4: Customer Bill Impacts - Percentage Increase from 2017 GUIC Class Monthly Bill to 2018 Class Monthly Bill, Overlapped 2017 and 2018 Class Monthly Bill

		2017 GUIC Rider (Docket 16-891)	2018 GUIC Rider (Docket 17-787)		Overlapped 2017 and 2018 GUIC Riders	
	Average Monthly Usage (therms)[11]	Current Monthly Bill due to 2017 GUIC	Proposed [12] Monthly Bill Increase due to 2018 GUIC	Percent Increase/ (Decrease) from 2017 Monthly Bill	Total Proposed Monthly Bill due overlapped 2017 and 2018 GUIC Riders	Percent Increase/ (Decrease) from 2017 Monthly Bill
Residential	70	$1.93	$3.76	94.6%	$5.70	194.6%
Commercial Firm	480	$7.24	$14.64	102.2%	$21.87	202.2%
Commercial Demand	16,990	$192.53	$427.18	121.9%	$619.71	221.9%
Interruptible	22,775	$184.80	$415.99	125.1%	$600.78	225.1%
Transport	663,538	$2,173.75	$4,558.51	109.0%	$6,732.26	209.0%

For a step-by-step walk through and flow chart of how TIMP and DIMP projects become charges on a customer bill, please see DOC Attachment 1.

III. DEPARTMENT ANALYSIS

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 a 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

[11] DOC IR No. 51.A included as DOC Attachment 2.
[12] *Petition Supplement*, Attachment Q.

determine the need for replacement or modification of existing infrastructure.[13] 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.[14]

A utility seeking approval of a GUIC Rider must file a petition with the Commission detailing the projects and costs proposed for recovery.[15] The petition for rate recovery is to be of only incremental costs.[16] 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.[17]

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

[13] Minn. Stat. § 216B.1635, Subd. 1(b), (c).
[14] Minn. Stat. § 216B.1635, Subd. 1(b) (3).
[15] *Id.*, Subd. 2-3.
[16] *Id.,* Subd. 2
[17] *Id.*, Subd. 4.

prudent costs to ratepayers.[18] 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.[19]

Xcel included a compliance matrix for the filing requirements specified in Minn. Stat. § 216B.1635 and in prior Commission orders (Attachment A to its initial *Petition*).
The Department concluded that Xcel Gas' filing reasonably complies with the filing requirements, with the exception of Minn. Stat. § 216B.1635, Subd. 4 (2) (iii), which reads:

> (2) a gas utility must file sufficient information to satisfy the commission regarding the proposed GUIC. The information includes, but is not limited to:
> …
> (iii) 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; [emphasis added]

Xcel's *Petition* omitted a report of the costs and salvage value associated with the existing infrastructure replaced or modified. Rather, Xcel's compliance matrix refers to Section IV.H of its petition where the Company provides estimated costs and salvage value of the new infrastructure projects it is undertaking, as complying with this statutory requirement.[20] The statute clearly requires the petitioners to provide this information on *existing infrastructure replaced or modified*. This required information would aid the Department in conducting its analysis. In fact, the Department raises issues related to the consideration of existing plant replaced/retired by GUIC projects in Section III.D.1 to which the upfront disclosure of such data would have been useful.

The Department requests that the Company file the required information in its Reply Comments. Also, the Department recommends that the Commission direct the Company to include such a report in future GUIC Rider petitions.

In addition to statutory filing requirements, prior Commission orders have required Xcel to include certain reports in its GUIC petitions. In its February 8, 2018 Order in Docket 16-891, the Commission directed Xcel to file a cost/benefit analysis of the sewer conflict inspection program in future GUIC petitions if the Company wishes to recover costs of the project through the rider mechanism. This directive was responsive to the Department's comments in that docket describing the challenges faced to obtain information to fully evaluate this particular program. In Attachment I to this instant *Petition*, the Company complied and provided the required analysis. Xcel's analysis demonstrated that the cumulative cost savings of $1.4 million

[18] *Id.,* Subd. 5.
[19] *Id.*, Subds. 2 and 4.
[20] See Xcel's compliance matrix provided in initial filing, Attachment A, p. 2.

has been realized through 2017 by using contractor services over in-house costs for specialized equipment ownership and increased workforce needs. Xcel expects this 10-year project to be completed in 2019 and expects continued year-over-year comparable cost savings. The Department reviewed and concluded that the Company's analysis is reasonable. The Department appreciates Xcel's upfront provision of the information.

B. PROJECT ELIGIBILITY

Xcel's *Petition* includes projects previously approved for recovery in earlier GUIC filings and does not propose new projects. Further, Xcel has fully completed its East Metro Pipeline Replacement Project. 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.[21] However, as discussed in Section III.D.5 below, the Department has identified cost-related concerns regarding Xcel's proposal.

C. PROJECTED GUIC ACTIVITY AND RIDER DURATION

Regarding the GUIC Rider duration, the Commission stated in its *Order* in Docket 14-336 that it would:

> …have an opportunity to review the GUIC rider on an annual basis and to make any needed adjustments or require the Company to file a rate case, if that is appropriate. For this reason, the Commission finds it unnecessary to set a definite end date for the GUIC rider.

Due to this conclusion, the Department makes it a habit each year to review whether or not the GUIC Rider should have an end date prior to its statutory end date of 2023, and also whether the Company should come in for a rate case. To this end, the Department reviewed the Company's projected GUIC expenditures and revenue requirements, as well as its recent effective return on rate base.

In its *Petition Supplement*, Xcel provided its updated plan for TIMP and DIMP project expenditures. The total TIMP and DIMP projected expenditures from 2019 through 2022 are shown in Table 5 below.

[21] Sometimes projects need to be reevaluated when new information arises. For example, the Crossover Pipeline Project was originally assessed as a high-risk pipeline, thus needed remediation to address safety risks; therefore, the Crossover Project costs were included in the GUIC Rider. However, Xcel recently discovered additional information, and once the overlooked pressure test documentation was taken into account, the project was re-scored and assessed as a low-risk item. Xcel will remove this projects' costs from the GUIC Rider in its Reply Comments. DOC IR No. 55 included as DOC Attachment 3.

Table 5
Xcel's Projected 2019-2022 TIMP and DIMP Expenditures
($ Millions)

	2019		2020		2021		2022	
	Capital[22]	O&M[23]	Capital	O&M	Capital	O&M	Capital	O&M
TIMP	$26.82	$2.55	$20.47	$1.49	$30.94	$1.48	$30.79	$1.48
DIMP	$34.14	$2.78	$26.85	$0.58	$17.27	$0.58	$17.27	$0.58
Total	$60.96	$5.33	$47.32	$2.07	$48.21	$2.06	$48.05	$2.06

The above table indicates that the Company is planning to continue to use the GUIC Rider.

The Department also reviewed Xcel's Annual Jurisdictional Report for 2017.[24] The weather-normalized overall return on rate base for 2017 was 7.01 percent, and is projected to be 6.75 percent in 2018. While neither of these figures are audited by regulators, both are less than the rate of return authorized in the Company's last gas rate case (8.28 percent). While the Department's proposed 2018 GUIC rate of return (7.02 percent) is lower than the ROR approved in its last gas rate case, it is effectively equal to the Company's 2017 actual ROR, and higher than its projected ROR for 2018.

Since the Department's proposed ROR is bracketed by Xcel's allowed ROR on base rates and effective ROR, it does not appear that enough value would be captured by ending the GUIC or by requiring the Company coming in for a rate case. At this time, the Department does not recommend that the Commission end the GUIC Rider or recommend that a general rate case be filed. However, as noted in the *Issues* section next, the Department has identified issues with Xcel's recovery proposals that should be addressed.

The Department intends to continue to monitor Xcel's cost recovery proposals and rate of return on rate base proposals in future filings.

D. ISSUES IDENTIFIED

The Department conducted its review of the Company's *Petition* and raises several issues with Xcel's proposal. These issues are discussed separately below.

[22] *Petition Supplement*, Attachment E.
[23] *Petition Supplement*, Attachment J. TIMP figures are not total expenditures, but post-MN Allocated expenditures.
[24] Docket 18-04.

1. *Concerns with Certain Revenue Requirement Components*

a. *Rate Base*[25]

Xcel Gas' GUIC Rider includes a rate base amount upon which a return on investment is calculated for GUIC rider recovery purposes. The GUIC net rate base amount comprises three components: plant-in-service, accumulated depreciation, and accumulated deferred taxes. Per Section 216B.1635, the GUIC Rider should include only the incremental costs associated with GUIC projects. From its review of the Company's *Petition*, the Department concluded that the Company's 2018 GUIC rate base is overstated because it is not appropriately adjusted to reflect only the incremental change in plant-related costs for rate setting. The issue was brought to light from Xcel's adjustment to the accumulated depreciation element of the GUIC rate base components for removal costs, as this adjustment as currently executed is an incomplete quantification of incremental changes, favoring shareholders to the detriment of ratepayers.

i. *Background of Accumulated Depreciation Reserve*

Briefly, accumulated depreciation generally acts to reduce rate base. The accumulated depreciation balance in its most basic form represents the amount of an asset investment that has been "used up" for ratemaking purposes. However, in more complex applications, the accumulated depreciation balance also reflects, in part, future projected expenditures related to the disposal of an asset (or removal costs) on its retirement. The assets that are known to cause the owner a future liability or cost that exceeds any remaining value have "negative net salvage values."

Natural gas pipelines are assets that have a negative net salvage value; thus on retirement, additional expenditures are expected to be incurred to remove the asset from service. To account for the additional expenditures expected at the asset's end-of-life, pipeline asset depreciation factors are designed to build in estimated removal costs; as a result, the annual calculated depreciation expense not only reflects a portion of the original investment cost, but also the estimated future removal costs, amounts that too are accrued over the useful life of the asset. The summed total of depreciation expense that has accrued over time is reflected in the accumulated depreciation reserve account. Therefore the accumulated depreciation reserve includes recovery-to-date of the original cost of the pipeline, or the upfront investment, as well as the expected future cost expenditures to remove the pipeline from service.

As a basic example, a $1,000 asset (plant item) is placed in service in 2006, with an estimated useful life of 10 years. This asset has an estimated negative net salvage value equivalent to 22 percent of original cost, or ($220). After the 10-year period, 100% of the original cost would be depreciated as well as an additional 22% of the original cost to account for the expected future

[25] *Petition,* Attachments F and G.

expenditures to remove/decommission the asset. Therefore, the calculated depreciation factor, applied annually, would be 12.2%. In 2010, after four in-service years, the depreciation reserve would have accumulated a $488 balance; thus the net rate base would be $522 (that is $1,000 original cost reduced by $488).[26] Essentially, $400 of the $488 accumulated depreciation balance represents recovery of the asset's original cost and the remaining $88 is recovery of the future expected removal costs, as summarized in the following Example 1:

ii. Proposed Accumulated Depreciation Reserve Adjustment

Several of the GUIC projects replace (or retire) existing natural gas pipeline assets. Xcel explained that when GUIC pipeline projects are installed, the Company accounts for the existing pipeline removal costs activity in the GUIC Rider rate base and does so by adjusting the

Example 1:		Asset A.1	
		Annual	After 4 years
Useful Life (Yrs)	10		
Salvage Value	-22%		
Original Cost	$ 1,000		
Depreciation Expense			
Original Cost		$ 100	
Negative Salvage Cost		$ 22	
Total		$ 122	
Accumulated Depr. Reserve			$ 488
Net Book Value (Rate Base)			$ 512

accumulated depreciation reserve balance.[27] The effect of the "removal-costs adjustment" reduces the accumulated depreciation reserve balance and, therefore, increases the GUIC rider rate base (and revenue requirement). However, the Department observed that Xcel's approach of including removal-costs for the old plant by adjusting the accumulated depreciation reserve alone fails to achieve the required objective to arrive at the incremental change in costs for purposes of GUIC rate recovery. To determine incremental costs, the Department points out that the relevant approach is to evaluate holistically the extent to which the now-replaced asset contributed to base rates.

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[26] For simplicity sake, the example's stated "rate base" omits the effect of averaging the beginning/end of period plant balances and reserves.
[27] DOC IR No. 14.D and 41.A included as DOC Attachment 4.

In DOC IR No. 8, the Department asked where in the filing Xcel included adjustments to rate base for the old plant being removed from service; this information is needed to evaluate the extent to which the now-replaced asset is recovered in base rates so that only the cost differential of the new infrastructure is included in the GUIC rider rate base. In its response, the Company explained it is unable to identify the specific plant assets replaced due to use of the group accounting method.[28] Group accounting is often used to treat large quantity assets of like nature as a whole, rather than individual assets. The Company's response appeared to further reason that no adjustment to plant balance was needed because when pipeline plant is retired, it is removed from the Company's books at a net zero balance, and that assets being replaced have a net book value far lower than their initial value.

Though the response is informative on the *current value* assumed for the retired plant, it is not on point because it fails to show that Xcel's proposed GUIC rate base represents only the incremental change in costs compared to the amounts that continue to be charged to ratepayers in base rates for the portion of its system being replaced. Instead, the response demonstrates that Xcel did not represent the 2010 test year "snapshot" of the replaced assets' contribution to base rates to arrive at an incremental cost amount for rider recovery purposes.

Not all the pipelines being replaced by GUIC projects were fully depreciated at the time of Xcel's last gas rate case; this fact must be taken into account to determine the incremental costs for the GUIC Rider. Specifically, the Department noted that when Xcel's last gas rate case test year was established, some of the existing plant (recently replaced by GUIC projects) had positive years of life remaining, as shown in its response to DOC IR No. 8, Attachment A.[29] Because this response data indicates that some of the existing plant was not fully depreciated as of the 2010 test year, without regard to salvage value, the plant was part of the 2010 test year rate base; hence the rates charged to Xcel's ratepayers continue to include recovery of these facilities. Specifically, Xcel's current base rates include a return on the balance of plant that was not fully depreciated, along with all other associated costs.

Xcel's *Petition* included the removal (or salvage) costs of the old plant in the 2018 GUIC Rider by adjusting the accumulated depreciation, which effectively increases the proposed 2018 GUIC rate base; however, Xcel did not similarly adjust the GUIC rate base downward to account for any of the undepreciated portion of the old plant's original cost included in the 2010 test year. Xcel's proposal is unbalanced because it made partial adjustments in the rider rate base which benefitted its shareholders, without reflecting the remaining necessary adjustments that would benefit ratepayers.

As a result, Xcel's *Petition* overstates the incremental cost for the GUIC recovery rider. By only including removal costs of the existing plant in the GUIC rate base without also adjusting the

[28] DOC IR No. 8 included as DOC Attachment 5.
[29] DOC IR No. 8 included as DOC Attachment 5.

proposed GUIC rate base by the 2010 test year remaining original cost of the existing plant replaced, Xcel's unbalanced proposal would overstate incremental costs. Overstated incremental costs lead to overstated rider revenue requirements; that is, Xcel would double recover certain costs, once in base rates and again in the rider. In this instance, without correction, Xcel would continue to charge ratepayers in base rates for the costs of now-retired/replaced pipeline assets that are no longer used and useful or in service due to the GUIC project, on top of charging ratepayers through the rider for the full cost of the placed-in-service, renewed pipeline-system assets.

The Department recommends that the Commission require Xcel to include only incremental rate base amounts in its GUIC Rider rate base. If Xcel Gas cannot reasonably determine the remaining original book value[30] of existing plant included in base rates that have since been replaced or retired due to GUIC projects, then at a minimum Xcel Gas should also not be allowed to adjust the GUIC rider's accumulated depreciation reserve by removal costs of the old plant.

b. Depreciation Expense

In the *Petition*, the Company included a recovery request for depreciation expense. The Company calculated depreciation expense by applying a depreciation rate[31] to the average monthly 2018 GUIC plant-in-service balance. Schedules with detailed calculations were provided by the Company in its response to DOC Information Requests included as DOC Attachment 6 to these comments.[32] The Department raises two concerns with the Company's proposed depreciation, (1) the expense amount recoverable through this rider, and (2) the depreciation factor used to calculate the GUIC projects' depreciation.

i. Depreciation Expense recoverable through the Rider

Per statute Section 216B.1635, Subdivisions 2 and 4, the GUIC Rider should include only the incremental amount of costs, one of which is depreciation expense. From its review of the *Petition*, as discussed above, the Department concluded that the Company's requested depreciation amount for the GUIC Rider revenue requirement is not the incremental expense amount. Rather, the Company has overstated the rider-recoverable depreciation expense.

In the 2018 GUIC *Petition*, the Company used an average GUIC plant-in-service balance and the latest-approved depreciation factors to calculate the depreciation amount requested to be recovered. The plant-in-service balance reflects the capitalized cost of the GUIC projects placed

[30] Excluding salvage accumulations.
[31] See *Petition*, Attachment K for inputs used by Xcel.
[32] DOC IR Nos. 44 and 45 included as DOC Attachment 6.

in service.[33,34] However, the resulting depreciation amount calculated on the GUIC average plant balance was not adjusted by the depreciation expense amounts currently being recovered in base rates that are relevant to the plant replaced (or retired) by the GUIC projects.

Xcel's base rates, established in its most recent gas rate case (Docket No. G002/GR-09-1153), included depreciation expense calculated on the original cost of the plant that was in place during the test year (2010). The depreciation amounts included in base rates were determined using the then-approved depreciation factors from Docket No. E,G002/D-07-1528.

Because Xcel Gas did not adjust the GUIC-projects' depreciation expense by the base-rates' depreciation amount tied to the plant replaced (or retired), the depreciation expense proposed for recovery in the rider is not incremental. As a result, the Department notes that Xcel Gas has overstated the depreciation expense included in its GUIC filings. The Department recommend that the Commission require the Company to recalculate the incremental depreciation expense amount by accounting for the depreciation expense amounts included in base rates relevant to the plant assets replaced by (or retired through) the GUIC projects included in this rider.

ii. Depreciation (Factor) Rate Used to calculate Depreciation Expense

In calculating depreciation expense for the GUIC projects, the Company used depreciation factors that were approved in its last depreciation filing (Docket No. E,G002/D-12-858). However, Xcel had a pending depreciation filing, Docket No. E,G002/D-17-581 (Docket 17-581) that has since been heard by the Commission on April 26, 2018, in which the Company proposed a change to its depreciation methodology, and ultimately, its depreciation factors. In its response to DOC IR 37.2, Xcel Gas estimated a $540,000 reduction in the 2018 GUIC revenue requirement if the depreciation changes proposed in Docket 17-581 were approved and applied to GUIC projects herein.[35] The Department recommends that the Company incorporate and apply the recent Commission-approved depreciation factors in Docket 17-581, when calculating GUIC-projects' depreciation in this *Petition*.

c. Property Taxes

Xcel Gas included property tax expense in its 2018 GUIC Rider revenue requirements. Per statute Section 216B.1635, Subdivisions 2 and 4, the GUIC Rider should include only the incremental amount of costs, one of which is property tax expense. From its review of the *Petition*, the Department concluded that the Company's requested property tax expense included in the 2018 GUIC Rider revenue requirement does not reflect the incremental expense amount. Rather, the Company's methodology overstates the rider-recoverable property tax expense.

[33] *Petition*, Attachments F and G
[34] DOC IR No. 40 included as DOC Attachment 7.
[35] DOC IR No. 37 included as DOC Attachment 8.

Xcel Gas calculated the proposed property tax amount for the GUIC by multiplying the GUIC plant balance (original cost) by an estimated property tax rate of 1.7 percent.[36] Since property tax rates vary by jurisdiction where Xcel's gas pipeline assets are located, the Company derived the overall composite 1.7 percent rate by dividing the Company's total calendar year personal property tax paid by the total original cost of personal property at the start of the tax year. For instance, the Company divided the 2016 personal property tax assessment (which is later paid in 2017) by the original cost of gas utility personal property measured at the close of December 31, 2015.

While the Department does not object to the Company's approach to derive an approximate composite property tax rate, it is the Company's application of the 1.7 percent rate to an *unadjusted GUIC plant balance* that fails to reflect incremental costs. Rather, the differential between the cost of the GUIC project placed in service and the original cost of the plant replaced (or retired) by the GUIC project should first be determined; then, only the differential should be subject to the property tax rate in order to develop the incremental property tax expense arising from GUIC projects.

Xcel Gas' base rates already include property tax recovery imputed on the value of the plant that has since been replaced (or retired) by GUIC projects; for that reason there is a need to isolate only the differential between new and old plant original cost amounts. The GUIC Rider is to include only incremental costs associated with GUIC projects. Therefore, the Department recommends that the Commission require Xcel to recalculate the incremental property tax expense amount for all GUIC years by adjusting original cost of GUIC projects by the original cost of plant assets replaced by (or retired through) the GUIC projects in each year, prior to applying Xcel's calculated property tax rate. Any overstated revenue requirements should be credited back to ratepayers.

d. 2018 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."[37] In compliance with this statutory directive, the Commission set the authorized 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 used the same capital structure and authorized ROR on debt (taken from Xcel's 2013 electric rate case, Docket No. E002/GR-13-868), only updating the authorized ROR on common equity, from 10.09% in 2015, to 9.64% in 2016, and 9.04% in 2017.

[36] DOC IR No. 43 and Email on IR 43 included as DOC Attachment 9.
[37] Minn. Stat. § 216B.1635, Subd. 6.

For 2018, Xcel proposes to again maintain the capital structure and authorized ROR on debt used for past years, but update the authorized ROR on common equity to 10.00%, resulting in an overall authorized ROR of 7.52%.

The Department does not support Xcel's proposal and instead supports maintaining the authorized ROR at 7.02%, as approved in February, 2018. Maintaining the overall ROR would adopt the Commission's past policy of using the same capital structure and ROR on debt from previous years, a policy that has worked well and which Xcel supports. The only difference from prior years would be that this policy would be extended to the ROR on common equity, keeping the overall ROR unchanged. This slightly altered policy would make the ROR aspect of the GUIC Rider consistent with how the ROR is applied to general rates, in which the ROR is not updated year to year. Further, this approach would make the GUIC Rider more consistent with other rates and streamline regulatory review. As a result, given the information available at this time, the Department concludes that maintaining the overall ROR from year to year is in the public interest.

2. Prorated ADIT and Rate Effective Date

Xcel Gas proposed to implement its 2018 GUIC revenue requirement rate factors prior to the close of the 2018 calendar year. Because of Xcel's proposed rate implementation timing, the Company's 2018 GUIC revenue requirements are increased due to the impact of prorating the accumulated deferred income tax (ADIT) projections.

ADIT reflects tax costs charged to ratepayers in rates, but not yet paid by the utility to the income taxing authority. In utility ratemaking, ADIT balances reduce rate base upon which a rate of return is calculated because ratepayers funded this operating cost in advance.

Prorating ADIT is required by the Internal Revenue Service (IRS), as part of normalization requirements for ratemaking, when forecast test periods are used in setting rates and the rates are implemented prior to the end of the test period. The prorated ADIT methodology reduces the credit to rate base for ratemaking purposes than would otherwise occur by using averaging typically applied to other rate base components; thus the prorated ADIT method increases rates charged to ratepayers. See DOC Attachment 10 to these comments for more extensive explanation of the prorate ADIT method.

Although this rider is subject to true-ups, an IRS-issued private letter ruling (PLR) on the matter, to an undisclosed utility company, indicated the effect of using prorated ADIT cannot be undone within a rider true-up.[38] Because of the ongoing harm to ratepayers, and the fact that

[38] IRS PLR 201717008 released April 28, 2017, https://www.irs.gov/pub/irs-wd/201717008.pdf at page 14, ordering paragraph 4.

the IRS has provided an opportunity to avoid harm entirely by implementing the rate at least one day after the test period, the Department objects to implementing a rider rate in midst of the forecast test period.[39]

To reasonably resolve this issue, in recent orders the Commission has directed rider rates to be implemented no sooner than the first day after the test period, recognizing that a rider is an extraordinary cost recovery mechanism enabling costs to be recovered outside of a rate case.[40] The Department fully supports this approach as being consistent with IRS requirements and reasonable ratemaking principles. Therefore, the Department recommends that the Commission likewise direct that the implementation of the 2018 GUIC rate to occur no sooner than January 1, 2019.

3. Sales Forecast

In its 2017 GUIC Filing (Docket 16-891), the Company used a calendar month allocation adjustment with the goal of better matching sales to historical trends. In addition, Xcel Gas applied a Demand-Side Management (DSM) adjustment to account for the impacts of conservation on expected sales. The Department disagreed with this methodology and recommended that 2017 GUIC Class Factors be based on the Company's regression model results before monthly sales and DSM adjustments. In regards to the monthly sales adjustment, the Department stated that it was inappropriate because it adds an additional layer of complexity to the Company's sales methods; further, the Department was unable to fully replicate the monthly re-allocation method.[41]

In Reply Comments of that filing, the Company stated:

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[39] *Id*. For example, at 7-8 and ordering paragraph 3:

> [I]f rates go into effect after the end of the test period, the opportunity to flow through the benefits of future accelerated depreciation to current ratepayers is gone and so too is the need to apply the proration formula. In this situation, the only question that is important for the purpose of rate base exclusion is the amount in the deferred tax reserve, whether actual or estimated. Once the future period, the period over which accruals to the reserve were projected, is no longer future, the question of when the amounts in the reserve accrued is no longer relevant (at the time the new rate order takes effect, the projected increases have accrued, and the amounts to be excluded from rate base are no longer projected but historical, even though based on estimates).

[40] Commission Order issued February 8, 2018 in Docket No. G002/M-16-891 *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 True-up Report for 2016, Forecasted 2017 Revenue Requirement, and Revised Adjustment Factors.* Commission Order issued August 24, 2017 in Docket No. G002/M-17-174 *In the Matter of the Petition of Northern States Power Company for Approval of a Modification to its Natural Gas State Energy Policy (SEP) Tariff, 2017 SEP Rate Factor, and 2016 SEP Compliance Filing*

[41] The historical adjustment discussed here should not be confused with the billing cycle/calendar month adjustment that accounts for the fact that billing months do not necessarily align with calendar months. The Department considers that adjustment to be perfectly reasonable, and has no objections to using it.

> Regarding the Department's first concern with re-allocating forecasted sales to match historical sales, the Company adjusts the monthly distribution of sales for the Residential, Commercial, and Small Interruptible rate classes. This adjustment is done to better align forecasted sales with historical actual sales on a calendar month basis in order to produce a monthly forecast that is more reflective of history than is the unadjusted forecast. The adjustments are done in a manner that ensures that the annual sales for a given calendar year remain unchanged; *i.e.*, the annual adjusted sales equal the annual unadjusted sales. Therefore, the Company is not changing the overall annual sales forecast. [Footnote: Furthermore, the additional layer of complexity claimed by the Department is minimal; sales are simply being moved between months within a year to better reflect historical patterns of sales, with annual totals not being changed.][42]
>
> We note that while the monthly adjustments are constrained so that annual sales do not change, when a different twelve month time period is considered, the adjustments may have a positive or a negative impact on sales. [Footnote: For example, for the twelve-month period of April 2017 to March 2018, the monthly adjustment process results in adjusted Residential sales being 0.3 percent lower than unadjusted sales, while adjusted Commercial and Small Interruptible sales each are 0.2 percent higher than unadjusted sales]. These are small impacts and will have a minimal effect on the calculated rate, whether it is a slightly higher rate or a slightly lower rate. Because the Company believes that it is appropriate to produce an accurate monthly forecast, we disagree with the Department's recommendation to eliminate these adjustments.[43]

At the Department's request, the Company also provided a forecast that did not include either the historical adjustment or the DSM adjustment.[44] In the Commission's 2017 GUIC Order, the Commission directed the Xcel "to establish rates based on unadjusted sales provided in Attachment F of Xcel's Reply Comments." Xcel filed compliance on February 20, 2018, and the Department filed a compliance verification letter on April 13, 2018.

In the instant docket, the Department requested spreadsheets of the Company's forecast in DOC IR No. 29. The Department noted that the forecast provided by Xcel did not include the

[42] Docket No. G002/M-16-891, Xcel Reply Comments submitted March 13, 2017, page 10.
[43] Docket No. G002/M-16-891, Xcel Reply Comments submitted March 13, 2017, page 10.
[44] Docket No. G002/M-16-891, Xcel Reply Comments submitted March 13, 2017, Attachment F.

DSM adjustment, consistent with the Commission's 2017 GUIC Order, but *did* include the historical adjustment.

This inclusion of the historical adjustment is not in line with the Commission's 2017 GUIC Order. The Department notes that the Commission's Order Point concerning the forecast technically only applied to the 2017 GUIC Rider, and not directly to the 2018 GUIC Factor. However, the Department observes that the Company updated other components of this year's filing to comply with the 2017 GUIC Order. Therefore, the Department is unclear as to why this particular component of the 2017 GUIC Order was not implemented in the Company's *Petition Supplement*.

Additionally, the Department noted that the Company's forecast produced lower sales than the actual sales reported in the Company's Gas Jurisdictional Annual Reports (GJAR). In the current GUIC proposal, the Company projects 2018 sales of 89,314,493 dekatherms (Dth) and 2019 sales of 91,556,339 Dth. However, in Xcel's GJAR,[45] the Company reports 2016 actual sales of 97,104,355 Dth and 2017 actual sales of 99,469,703 Dth.[46]

The Department is unclear as to why actual sales reported in the GJAR are so much greater than the forecasted sales projected in the instant docket. The Department notes that both sets of data are weather-normalized, but posits that the two different data sources might be weather-normalized in different ways. However, it currently appears that the Company may be under-estimating forecasted sales.

In Reply Comments, the Department asks that the Company provide an updated forecast, without the historical monthly adjustment. Further, the Department asks that the Company clarify why forecasted sales for 2018 and 2019 are so much lower than actual sales reported in the GJAR for 2016 and 2017.

4. NSP-MN GUIC Project Cost Allocation Between Minnesota and North Dakota

Xcel Gas provides natural gas service to both Minnesota and North Dakota. While reviewing Attachment J to the *Petition*, the Department noted that Xcel Gas split some GUIC natural gas transmission-related O&M costs between the two states.[47] The Department also noted that in Xcel Gas' first GUIC petition, specifically Attachment I to Docket 14-336, the East Metro Pipeline O&M costs were split between Minnesota and North Dakota. The East Metro Pipeline was a

[45] Docket Nos. E,G999/PR-17-4 and E,G999/PR-18-4.
[46] The 2010 forecasted sales approved in the Company's last rate case were 85,785,149 Dth.
[47] In Xcel Gas' Attachment I to its Docket 14-336, the East Metro Pipeline replacement O&M costs were split between Minnesota and North Dakota. The East Metro Pipeline was a transmission line prior to replacement and is now classified as a distribution pipeline.

natural gas transmission line prior to replacement and is now classified as a distribution pipeline. Xcel's subsequent GUIC filings have not shown any further sharing of East Metro Pipeline costs between Minnesota and North Dakota. It is also the Department's understanding that there are ongoing GUIC projects being undertaken or planned by the Company that effectively have or will change the classification of certain pipeline system assets from transmission to distribution upon completion. The Company's filing does not discuss GUIC project cost allocation between Minnesota and North Dakota.

Therefore, the Department requests that Xcel Gas, in its Reply Comments:

- identify all completed and proposed GUIC projects that change the classification of the gas pipeline/plant system (i.e., from transmission-to-distribution or vice versa),

- explain the characteristics that caused the reclassification,

- detail the cost allocation treatment of that gas system infrastructure and its associated O&M costs between the two states before and after such classification change, and

- identify all Xcel Gas system integrity management projects undertaken or planned in North Dakota that affect the cost allocation treatment of that gas system infrastructure and/or associated O&M between North Dakota and Minnesota.

5. Project Costs Proposed For Inclusion in GUIC Recovery Rider

The Department issued several information requests to evaluate the various TIMP and DIMP projects and their costs that Xcel proposed to recover through the rider. The Department has concerns with the following items, as discussed below:

- Data Gaps – Insufficient Documentation Leading to Costs
- TIMP – Island Line South Project
- DIMP – Langdon Line Project
- DIMP – Lexington to Snelling Project
- DIMP/TIMP – Expenditures on Replacement of Low-Risk Infrastructure

a. DATA GAPS – Insufficient Documentation Leading to Costs

Xcel indicated that 21 percent of its transmission pipeline (or 15.6 miles) cannot meet the maximum allowable operating pressure (MAOP) validation as required by the federal law (49 CFR 192.619) due to insufficient records. According to the guidance provided by the PHMSA's issued advisory bulletin, records must be "TVC", 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).[48]

To remediate the insufficient records to support MAOP validation, Xcel stated it must either replace the pipeline, or perform pressure tests; under either option, the total costs to do so will amount to millions of dollars.[49] For instance, two of Xcel's TIMP-based projects undertaken to satisfy MAOP, the *East County Line* (South St. Paul) and *County Road B line* (North St. Paul) are multi-year pipeline replacements projects[50] that have estimated costs of $5.3 million and $36 million, respectively.[51]

Xcel has not demonstrated to the Department that the necessary information on the pipeline characteristics and/or testing needed to validate MAOP was not available or possibly known at the time, or since, the pipeline was installed; this lack of demonstration leads the Department to question whether Xcel had failed to properly acquire, secure, or record information about its pipeline system. Although Xcel argues that some of the pipeline was installed prior to the existence of pipeline safety regulation established in 1970, the Department has not been persuaded by Xcel that being able to validate maximum operating pressure is an extraordinary requirement of a pipeline system operator.[52] Nor has Xcel made an overarching claim that this MAOP-validation documentation is lacking for all of its pipeline, to which the regulation applies, installed prior to the passage of certain regulations.

When asked to quantify the amount of its distribution system subject to federal MAOP regulations[53] that lacks record data to support MAOP, Xcel stated 53 percent of its Intermediate Pressure (IP) pipeline in the Metro Area lacks necessary documentation to satisfy MAOP requirements.[54] This amount equates to 40.5 miles of Metro Area natural gas pipeline.[55] Xcel stated that it has yet to evaluate the additional 207 miles of intermediate pressure pipelines in Greater Minnesota. It is not clear in the record whether those additional 207 miles are subject to federal MAOP regulations[56] as well; therefore, the Department requests Xcel to clarify in its Reply Comments: 1) the extent to which the additional 207 miles of intermediate pressure pipelines are subject to MAOP regulations and 2) any updates or other information on these lines that may be helpful.

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[48] See attached PHMSA Advisory Bulletin ADB-2012-06 included as DOC Attachment 11.
[49] DOC IR No. 35.C included as DOC Attachment 12.
[50] *Petition,* Attachment C, pp. 11-13.
[51] *Petition,* Attachment C1(e).
[52] DOC IR No. 24 included as DOC Attachment 13.
[53] 49 CFR 192.619
[54] DOC IR No. 35.C included as DOC Attachment 12.
[55] DOC IR No. 59 included as DOC Attachment 14.
[56] 49 CFR 192.619

Xcel stated that the remedies available to resolve the absence of data is to either conduct pressure tests (at a cost of $150,000 to $2 million per mile), or replace the pipeline (at a cost of $3 million to $8 million per mile). When applying these cost estimates to the Metro Area's 40.5 miles of intermediate pressure distribution pipelines lacking MAOP documentation, the range of Xcel's estimated costs equates to a $6 million to $324 million cost-range problem for the Metro Area lines alone. The newest pipeline without the necessary TVC documentation was installed in 1982, many years after the 1970 pipeline safety regulation was in effect.

The Department also noted that PHMSA's advisory bulletin states:

> PHMSA is supportive of the use of alternative technologies to verify pipe characteristics. Owners and operators seeking to use alternative or nontraditional technologies in the determination of MAOP or MOP, or to meet other regulatory requirements, should first discuss the proposed approach with the appropriate state or Federal regulatory agencies to determine its acceptability under regulatory requirements.[57]

The Department requests that Xcel, in Reply Comments, discuss whether or not it sought use of alternative technologies to determine MAOP in order to meet regulatory requirements and, if so, the results or status of efforts; and to discuss the economic analysis of doing so in lieu of pipeline replacements.

The operating system's data gaps are very concerning and problematic, especially since data records were and continue to be within the control of Xcel Gas' management. Therefore, the Department recommends that the Commission consider either: 1) limiting the "return on" the capital costs incurred to remediate the system's MAOP data gaps to Xcel's long-term debt costs or 2) not allowing extraordinary rider ratemaking treatment for projects where Xcel lacks sufficient data.

b. TIMP – Island Line South Project

The Island Line South project is a TIMP-based project described as 1.9 miles of 20-inch natural gas pipeline along the Mississippi River that Xcel is assessing to determine work that is needed. The Company proposes to include costs in the 2018 GUIC Rider attributed to Island Line expenditures; however, Xcel hasn't fully explained the reasoning and necessity for incurring certain costs.

First, the *Petition* indicates that this 1952 pipeline is slated for replacement, and small segments have recently been replaced; however, expenditures to construct ILI access, in addition to

[57] See attached PHMSA Advisory Bulletin ADB-2012-06 included as DOC Attachment 11.

planned expenditures to conduct ILI assessment, are requested for rider recovery. Xcel Gas did not provide adequate justification of the reasonableness and necessity to incur and charge ratepayers for the costs of ILI improvement and ILI assessment costs, in light of Xcel's planned replacement of this pipeline, has not been satisfactorily explained to the Department.[58] Therefore, the Department recommends that, at a minimum, that Xcel be directed to exclude the $0.6 million estimated costs of the ILI assessments to be performed on the Island Line South pipeline designated to be replaced.

Second, for this Island Line project, the Company attributed its estimate-to-actual variance to excessive water pumping costs, which too, had not yet been clearly supported by the Company's filing. The Company initially estimated project cost at $1.7 million, but the actual costs were $3.2 million, leaving a $1.5 million variance (an 88% cost overrun).[59] The Department notes that, even though natural gas utilities are required to provide information about actual costs compared to forecasted costs, no utility is entitled to recover cost overruns in a rider, particularly if the utility fails to demonstrate that it would be reasonable to recover such costs through a rider.

Xcel did not provide sufficient information in its initial filing to demonstrate the reasonableness of charging costs that were nearly double the amount that Xcel originally estimated. Further, although the Department obtained and reviewed correspondence and 2016 invoices for this project (DOC IR No. 56), this information did not substantiate the $1.5 million variance. Therefore, the Department concludes that Xcel did not demonstrate the reasonableness of including these cost overruns in the GUIC rider, thus should be removed from GUIC Rider recovery.

c. DIMP – Langdon Line Project

The Langdon Line project is one of Xcel's proposed distribution pipeline replacement projects.[60] The existing Langdon Line assessment was scored as a high risk line by Xcel due to the threat severity combined with its location in a high consequence area.[61] Design and construction is expected to be completed in 2018 and 2019. The project entails replacing six miles of varied diameter pipe (12-inch, 8-inch and 6-inch) installed in 1958 with a single diameter line that could support use of in-line inspection technology. Xcel proposed to use 12-inch pipe for this project, estimated to cost $12.5 million; after removing internal costs, the amount would be $11.8 million that Xcel would include in the 2018 GUIC Rider.[62]

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[58] DOC IR No. 17 and Email from Xcel included as DOC Attachment 15.
[59] Petition, Attachment T, Footnote 1.
[60] *Petition,* Attachment D, p. 9.
[61] *Petition,* Attachment D2(a), p. 6 and DOC IR No. 55.
[62] DOC IR No. 33 included as DOC Attachment 16.

The diameter of pipe used in pipeline projects influences the overall project costs. In its discovery responses to DOC IR No. 31, the Company estimated that if it used matching, varied pipe diameters when replacing the Langdon Line, it would reduce capital cost of this project by $4.4 million. Alternatively, when asked about the service adequacy and cost differential should a single diameter 8-inch pipe be used for this project, rather than the proposed 12-inch pipe, the Company responded that an 8-inch pipe would provide adequate service and reduce the project's installation cost by $3.6 million.[63] To defend its proposal to use a 12-inch diameter pipe, Xcel stated, "This will allow for ILI to be used on the entire line, which helps ensure gas system safety and reliability." However, the Department points out that the Company's response did not say that an in-line inspection tool could not be used on an 8-inch diameter pipe.[64]

Because using an 8-inch pipe for the Langdon Line would adequately serve Xcel's customers, and likely be ILI compatible, it appears to the Department that Xcel's proposal to replace the current pipeline (which consists of 6-, 8- and 12-inch pipe) with a 12-inch pipe for the entire line is not prudent, and appears to constitute a betterment. Statute section 216B.1635 Subd. 5 states:

> …the commission may approve the annual GUIC rate adjustments provided that, after notice and comment, the costs included for recovery through the rate schedule are prudently incurred and achieve gas facility improvements at the lowest reasonable and prudent cost to ratepayers.

In addition, Statute section 216B.1635 Subd. 1 (b)(3) states that GUIC means costs incurred in gas utility projects that:

> …do not constitute a betterment, unless the betterment is based on requirements by a political subdivision or a federal or state agency, as evidenced by specific documentation, an order, or other similar requirement from the government entity requiring the replacement or modification of infrastructure.

It is the Department's understanding that use of in-line inspection technology on distribution pipelines is not mandated by any government body or regulation. Further, the Company did not provide support that an in-line inspection tool could never be used on an 8-inch diameter pipe currently, or sometime in the future. According to an article issued by a pipeline engineering firm,

[63] DOC IR No. 31 included as DOC Attachment 17.
[64] In DOC IR No. 32 response regarding a different pipeline replacement project (H005 – Lexington to Snelling), the Company indicates use of 8-inch pipe for that project will allow for use of ILI technology. DOC IR No. 32 is included as Attachment R to these comments.

> The continued sophistication and miniaturization of the electronic systems used in the intelligent pigs has allowed the development of smaller pigs that can be used in small-diameter pipelines.[65]

Also, the abstract of a recent article *Advances in the Inspection of Unpiggable Pipelines* published by the University of Leeds, School of Mechanical Engineering states in part:

> The field of in-pipe robotics covers a vast and varied number of approaches to the inspection of pipelines with robots specialising in pipes ranging anywhere from 10 mm to 1200 mm in diameter.[66]

The Department agrees that having little or no pipe diameter variation on this segment is preferable to facilitate potential use of in-line inspection tools; however, the recoverable amount for the Langdon Line project through the 2018 GUIC Rider should be limited to a project cost assuming an 8-inch pipe, rather than the 12-inch, to achieve gas facility improvements at the lowest reasonable and prudent costs to ratepayers and to adjust out system uprate costs. Therefore, when the Langdon Line project is placed in service, the Department recommends that the Commission require that the project amount includable in the 2018 GUIC Rider rate base be reduced by the project cost differential between use of a 12-inch and an 8-inch pipe, estimated to be approximately $3.6 million. This recommendation does not preclude Xcel from requesting full project cost recovery in its next rate case.

d. DIMP – Lexington to Snelling Project

The H005 – Lexington to Snelling (H005) project is a 3-mile high-pressure distribution pipeline replacement estimated to cost $4.9 million, of which $4.6 million is proposed to be recoverable once internal costs are removed.[67,68] Xcel stated that the existing 1964 pipeline, which scored as high risk by Xcel's assessment, has a history of leak repairs, most notably caused by material failure, mechanical defects, third party damage and corrosion. Xcel plans for the new pipeline to be constructed in a manner to allow for use of in-line inspection tools.

In its undertaking of this particular pipe replacement, Xcel proposes to relocate approximately 20 services currently connected to this line; to do so, it would extend a nearby pipeline system to facilitate transfer of customer services to this alternate line. In response to DOC IR No. 32.B,

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[65] *Pig Trap/ Pig Launcher/Intelligent Pig* issued February 17, 2016 by Subsea Pipeline Engineering. https://sabrinapurba.wordpress.com/2016/02/17/pig-trap-pig-launcherintelligent-pig/ accessed April 21, 2018.

[66] *Advances in the Inspection of Unpiggable Pipelines* , published November 29, 2017, written by George H. Mills, Andrew E. Jackson and Robert C. Richardson, University of Leeds, School of Mechanical Engineering; http://www.mdpi.com/2218-6581/6/4/36/htm accessed April 21, 2018.

[67] *Petition*, Attachment D, pp. 10-11.

[68] DOC IR No. 33 included as DOC Attachment 16.

Xcel explained that removing services from the H005 line would allow in-line inspection to be performed without disrupting service to large volume commercial customers.[69] Through discovery, Xcel responded that no regulatory directive prescribed that services not be connected to high pressure distribution pipelines; rather, the Company opted not to reconnect existing services back to the new H005 pipeline. Xcel estimated that $420,000 of this project's cost is attributed to its proposed extension of other facilities in order to relocate services to a different part of its pipeline operating system.

Minn. Stat. § 216B.1635 Subd. 1 (b)(c)(2) states that "Gas utility projects" means:

> …replacement or modification of existing natural gas facilities, including surveys, assessments, reassessment, and other work necessary to determine the need for replacement or modification of existing infrastructure that is required by a federal or state agency.

The Department concludes that the costs attributed to extend another part of Xcel's pipeline, to enable Xcel, at its option, to transfer services to another section of its system, do not satisfy some authority's requirement and do not fit under the definitions of the statute. Therefore, the Department recommends that $420,000 of the H005 project costs be excluded from GUIC recovery rider. Again, this recommendation does not preclude Xcel from requesting full project cost recovery in its next gas rate case.

e. DIMP/TIMP – Expenditures on Replacement of Low-Risk Infrastructure

In the Department's investigation, Xcel disclosed in response to DOC IR No. 35 that it included in the 2018 GUIC Rider costs incurred for low-risk distribution infrastructure replacement undertaken in conjunction with work activity for high risk remediation projects.[70] Xcel explained that it opted to do this additional work to minimize disruption to the local community. The low-risk DIMP capital expenditures identified totaled approximately $85,000. Because these expenditures on low-risk infrastructure replacement were elective, not supported by civic/public work requirements, nor required by government regulations, the Department recommends that Xcel remove these costs from the GUIC Rider.

In addition, Xcel later identified that the TIMP-based Crossover Pipeline Project previously included in the GUIC Rider, was incorrectly scored as high risk, when in fact should have been scored as a low-risk project, once previously overlooked pressure test records were taken into account. Project design occurred in 2017 and Xcel planned construction for 2018.[71] Xcel had included incurred Crossover Pipeline Project costs in the prior 2017 GUIC Rider, and has now

[69] DOC IR No. 32 included as DOC Attachment 18.
[70] DOC IR No. 35 included as DOC Attachment 12.
[71] *Petition*, Attachment C, p. 14.

committed to removing that project's costs from its revenue requirement and reversing prior rider recovery, in its forthcoming Reply Comments' revised schedules.[72] The Department appreciates Xcel's additional review efforts and the corrective action to remove this low-risk project and its costs from the GUIC Rider.

6. Review of Contracts, Work Orders, and Invoices

In Docket 16-891 (2017 GUIC), the Department expressed concerns regarding the contracts, invoices, and work orders related to software costs for Xcel's Pipeline Data Project (PDP). Initially, the Department noted that Xcel executed a contract for a project that included all of Xcel's utility affiliates, but failed to provide evidence that assigning these costs solely to Minnesota ratepayers was reasonable. In response to this concern, the Company stated that all work was done in Minnesota, providing a new Minnesota contract, as well as invoices and a map related to the PDP work. However, the Department found that some work orders contained different project numbers than either the original Minnesota contract or the newly provided Minnesota contract. The Department further found that Xcel provided work orders with invoice numbers that corresponded to its contract with Xcel's Colorado utility affiliate (the Public Service Corporation of Colorado, or PSCo). The Department also noted that some of the work orders included costs that were associated with projects that were not the PDP.

As a result of these discrepancies, the Department recommended that the Commission reject the Company's proposed level of DIMP software costs. Instead, the Department suggested that software costs be allocated to Minnesota ratepayers. The Commission supported the Department's recommendation.

In the instant docket, the Department conducted a three-step jurisdictional inspection of Xcel's contracts, work orders, and invoices. The first step was reviewing the contracts themselves to determine which parties were included in the contracts. The second step involved reviewing the Company's contract-specific cost data provided to the Department. The third step involved auditing invoices and work orders from the Company's data set.

The Department submitted three IRs asking for details on the Company's data, work orders, and invoices: IR 49, IR 62, and IR 63. Both Public and Trade Secret versions of the Company's responses are provided in Attachment 19 to these Comments. Results and information pertaining to this jurisdictional review are provided in Public and Trade Secret versions in Attachment 20 to these Comments.

Finally, the Department notes that this jurisdictional review did not cover all costs that the Company proposed to include in the GUIC, but only costs that could be traced back to a specific

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[72] DOC IR No. 55 included as DOC Attachment 3. The 2018 revenue requirements of $100,094 will be removed, along with a credit for the 2017 revenue requirements of $4,140.

vendor or contract. The following table shows all of the Company's total incurred Capital and O&M costs (prior to the removal of non GUIC-eligible work) by whether these costs are included in the Department's review.

Table 6. Total 2017 O&M and Capital GUIC Costs to Xcel by Inclusion in the Department's Jurisdictional Review of Costs

	Included in Department's Jurisdictional Review (costs able to be traced back to specific contract)	Not included in Department's Jurisdictional Review (costs not able to be traced back to specific contract)	Total[73]
O&M	$4,327,128	$3,691,042	$8,018,170
Capital	$17,366,758	$8,276,882	$25,643,640
Total	$21,693,886	$11,967,924	$33,661,810

The Department is not concerned about the O&M costs not included in the Department's jurisdictional review, as these costs largely comprise the Company's pre-2015 amortized costs already approved for recovery.

However, the Department continues to have concerns about the capital costs that cannot be traced back to a contract, despite the Department's attempts to understand more about the nature of these costs. While not all of the non-contract work has been included in Xcel's GUIC, it is not clear how much has actually been removed from the Rider. Further, the Company has explained in discovery that these costs largely comprise allocated and overhead expenses, but did not provide sufficient evidence to demonstrate that these costs were in fact GUIC-eligible. Ultimately, the Department was unable to verify that these costs were actually specific to work performed in Minnesota, or even truly incremental to costs already included in base rates. Therefore, the Department concludes that the Company has not met its burden of proof in demonstrating that $8,276,882 in capital costs should be included in the GUIC Rider.

a. Contract Review

In step one of this process, the Department reviewed the [**TRADE SECRET DATA HAS BEEN EXCISED]** contracts provided to the Department in the Company's response to IR 49. However, the Department identified additional vendors in the Company's data set and asked about the additional vendors in IR 62. The Company provided additional contracts, bringing to total to [**TRADE SECRET DATA HAS BEEN EXCISED]** contracts. Further, in this process, the Company identified three non-contracted vendors who were used for one-time services.

[73] Total O&M and Capital Costs are based on Figures reported by Xcel in response to IR 49. Total costs are costs to the Company and do not reflect non GUIC-eligible costs that have been backed out.

The Department looked at the following in each contract:

1. Who were the parties to the contract?
2. What was the geographic scope of work in the contract?
3. Which states did pricing schedules in the contracts cover?

The Department found that in seven contracts, the parties were the vendor and "Northern States Power- Minnesota," which includes Minnesota and North Dakota. All other contracts were between a vendor and multiple Xcel affiliates. One contract was between a vendor and Xcel's Colorado affiliate. No contracts specifically were between a vendor and the Minnesota jurisdiction of NSP-MN. The Department's detailed findings are summarized in Attachment 20, Table 1, entitled "Contract Jurisdiction."

In response to IR 62, the Company clarified that it does not maintain separate contracts for different jurisdictions; rather, jurisdictions are tracked through work orders. However, without information as to the state(s) in which work was done, the Department concludes that, in this portion of the Department's jurisdictional review, Xcel did not meet its burden of proof to show that it would be reasonable to charge all of the costs solely to Minnesota ratepayers.

b. Data Review

In Step 2 of its jurisdictional review, the Department looked through the Company's full data set of all costs proposed for recovery that were affiliated with outside vendor contracts.

For this process, the Department first wanted to ensure that all outside vendor contract data could be traced back to the contracts provided via contract, master agreement, or work order number. In response to IR 62, the Company provided a data set and an explanation that allowed the Department to link the data to the contracts. While the Department found some discrepancies between the contracts and the data, these discrepancies were mitigated by other factors that allowed the Department to conclude that the data could appropriately be traced back to the contracts. The Department notes these discrepancies in Attachment 20 under "Data Jurisdiction."

Once the link between the contracts and data was established, the Department conducted a visual inspection of the charges affiliated with each vendor in the dataset provided to the Department in Attachment D from IR 62.

In looking at the description of each charge, the Department asked the following questions:

1. Does the description of the charge demonstrate that work was definitively performed in Minnesota?

2. Does the description of the charge demonstrate that the work was definitively *not* performed in Minnesota?

For example, the Department considered data points with the following descriptions to be work performed exclusively in Minnesota:

12320752-ST. PAUL-ETNA-BIRMINGHAM-WINCHELL BTN HOYT & ARLINGTON-2016	$417.07
12526379-INSTALL NEW MONTREAL LINE SOUTH	$4,054.75
12586221-FOREST LAKE- IMPERIAL AVE & 216TH - INSTALL 3265' OF 2" PE D	$2,639.45

Alternatively, the Department considered the data points with the following descriptions to be jurisdictionally unclear:

12440381-SEWER REPAIR - GUIC RELATED	$895
12487770-17 SEWER MITIGATION - DIMP/GUIC – CONTRACTOR	$ 3,275

For data that was jurisdictionally unclear from the description alone, the Department looked other data elements, besides the charge descriptions. For example, the above two data points were associated with a "WBS Name" that appeared to be Minnesota specific, as shown here:

12440381-SEWER REPAIR - GUIC RELATED	$895	MNGUIC – DMN Sewer Conflict Investigatio[n]
12487770-17 SEWER MITIGATION - DIMP/GUIC – CONTRACTOR	$ 3,275	MNGUIC – DMN Sewer Conflict Investigatio[n]

The Department considered this type of jurisdictional data to be less robust than the description data, as these data do not provide specific locations within MN. In order to demonstrate that all costs should be charged solely to Minnesota customers, Xcel would need to provide more specific geographical data. Therefore, the Department continued to consider this data jurisdictionally unclear, despite the fact that "MN" was part of the "WBS Name" data element. All charges identified by the Department to be jurisdictionally unclear were O&M charges, under contracts that contained both Minnesota and North Dakota (NSP-MN), totaling $2,994,264.

The results of step 2 in this jurisdictional review can be found in Attachment 20, Table 2, entitled, "Data Jurisdiction." In this table, the charges affiliated with each vendor are identified as either appearing to be MN-specific, unclear, or not applicable. The Department provides further detail for jurisdictionally unclear charges in Attachment 20, Table 3, entitled "Jurisdictionally Unclear Data," in which the specific unclear charges can be identified.

Additionally, in response to IR 62, the Company identified two vendors whose work was performed outside of Minnesota. The Company proposed to remove the work affiliated with these vendors in a final compliance filing, which the Department supports.

c. Work Order and Invoice Audit

In step 3 of its jurisdictional review, the Department requested from Xcel copies of specific work orders and invoices for both Capital and O&M spending.[74]

For Capital invoices, the Department requested work orders and invoices associated with 25 charges from the Company's dataset provided in IR 62, Attachment D. The Department requested:

1. The top 11 greatest capital charges in the dataset.
2. The top 5 greatest capital credits to vendors in the dataset.
3. 9 charges across different vendors, including no identified vendor, above $3,000.

For O&M Invoices, the Department requested work orders and invoices associated with 14 charges from the Company's data set provided in IR 49, Attachment A. The Department requested:

1. 6 of the top 20 greatest O&M charges in the dataset.
2. 2 of the top 25 greatest O&M credits to vendors in the dataset.
3. 2 charges associated with database management for a vendor with jurisdictionally unclear charges
4. 4 charges with no identified vendor, above $3,000.

In its audit of these invoices and work orders, the Department found that in the majority of documentation provided, with one exception, there was some kind of clear indication that the work was performed exclusively in Minnesota. The results are provided in Attachment 20, Tables 4 and 5, entitled "Capital Inv WO Jurisdiction" and "O&M Inv WO Jurisdiction," respectively.

The one exception was for invoices provided to the Company by **[TRADE SECRET DATA HAS BEEN EXCISED**] for database management and "managed services." This exception is notable

[74] In IR 49, the Department initially requested all work orders and invoices associated with all parent projects. In response, the Company noted that this would take too much time. Instead, Xcel provided the Department with multiple data sets related 2017 GUIC expenditures and offered to provide specific work orders and invoices upon request.

because, based on the jurisdictional review of this vendor's contract, the Department was unable to conclude that work done by this vendor was Minnesota-specific. In the data review, work done by this vendor was jurisdictionally unclear. Furthermore, the nature of the work, which is computer-based rather than located in a physical location, is something that could easily span multiple jurisdictions. Finally, in last year's GUIC Rider in Docket 16-891, the Department had concerns regarding software costs, similar to these database-specific costs.

d. Conclusion of Jurisdictional Review

The Department found that it was only able to perform a jurisdictional review of costs that could be tied back to a specific contract or vendor. Therefore, the Department was unable to review $8,276,882 in capital charges. Furthermore, while some of these charges may have already been removed from the Company's final GUIC-eligible figures, they seem to have largely comprised overhead and allocated costs. Therefore, the Department concludes that the Company has not met its burden of proof in demonstrating that these costs were either definitely in Minnesota, or truly incremental to costs already included in base rates.

Based on the costs that were included in the jurisdictional review, the Department concludes that, while Xcel demonstrated that some of the costs were for work exclusive to Xcel's Minnesota jurisdiction, the Company's system was not able to demonstrate that all of the costs were for projects performed only in Minnesota. Most notably, the Department found that the data review portion of this process contained $2,994,264 of costs that were jurisdictionally unclear because they did not provide the same level of detail as other costs in the Company's system. These costs were largely due to vendors whose contacts were executed by NSP-MN (which includes both MN and ND), although some jurisdictionally unclear costs contained no vendor and no contract number.

Therefore, the Department recommends that the Commission:

- Direct the Company to remove from the GUIC Rider $8,276,882 in capital costs not already removed unless the Company can adequately demonstrate that these costs are Minnesota-specific and incremental to costs captured in base rates;
- Direct the Company to use a jurisdictional allocator for all costs identified in Attachment 20, Table 3, unless the Company can provide invoices and work orders related to all of these charges; and
- Direct the Company to remove the work that is not Minnesota-specific, as identified by the Company in response to IR 62.

E. GUIC RIDER SCHEDULES

While a single year's GUIC Rider is not inordinately complex on its own, the implementation of various GUIC Riders over the years has made Xcel's GUIC a somewhat complex rider. For example, rates approved in Docket 15-808 are called the "2016 GUIC." These rates were in place from September 2016 through February 2018. However, the 2016 GUIC Rider revenues were only applied to the 2016 GUIC revenue requirement for the first seven months of that period; in the remaining 11 months, the 2016 GUIC Rider revenues were applied to the 2017 GUIC revenue requirement. To further complicate matters, the 2016 GUIC revenue requirement was also recovered by the revenue generated from rates approved in Docket 14-336 (the 2015 GUIC) over the period of January 2016 to August 2016.

This above example demonstrates how confusing and complicated this rider has become during implementation and tracking. The revenue requirements, rates, and recoveries of the GUIC Rider do not necessarily correspond in consistent or intuitive ways. In the instant docket, an additional layer of complexity was introduced in Xcel's *Petition Supplement*, as the Company proposed to concurrently charge the 2017 GUIC Rider alongside the 2018 GUIC Rider for the months of August 2018 through February 2018.

The Department was concerned that information was getting lost in this various activity, since the Company's "Monthly Trackers" (found in Attachment O of the Company's *Petition Supplement*) are primarily dedicated to monthly revenue requirements, with only the annual total recovery shown. The rates and monthly recoveries (and sales forecast) are presented separately in Attachment Q of the *Petition Supplement*. Further, while the Monthly Trackers in Attachment O show years 2016-2022, the information in Attachment Q only covers a 13-month span. This presentation, with revenue requirements tracked separately from recoveries and rates, makes it difficult to understand when, by which rates, and how much of each revenue requirement was actually recovered or is projected to be recovered. It also makes it very difficult to understand the actual balance of the GUIC Rider tracker at any given point in time.

As a result, it is difficult for the Department to verify any claimed carryforward balances and thus to ensure that the rates Xcel proposes to charge to ratepayers are "just and reasonable" as required by Minn. Stat. §216B.03, particularly when that statute requires that "[a]ny doubt as to reasonableness should be resolved in favor of the consumer."

At a minimum, the Department would prefer that, if Xcel continues to file future filings, the Company present its GUIC Rider tracker in a way that synthesizes the information in Attachments O and Q in the *Petition Supplement*, showing revenue requirements, rates, and recoveries on the same page. This approach not only would provide parties and the Commission with a better understanding of the GUIC Rider, but it would also be consistent with the format of at least one other rider tracker (the CIP Rider). Therefore, the Department recommends that the Commission require Xcel, in any future GUIC Rider filings, to present historical and projected GUIC Rider revenue requirements, rates, and recoveries within a single tracker for each year.

F. TRUE-UP REPORT, RECOVERY PERIOD AND TRACKER BALANCE CARRYING CHARGE

1. True-Up Report

Because the 2017 GUIC Rider is currently ongoing through February 2019, there is no true-up report at this time.

2. Recovery Period

Xcel requested to calculate the final rate adjustment factors to recover the 2018 GUIC Rider revenue requirements over an 8-month period, from August 1, 2018 through March 31, 2019. The Department presumes that Xcel proposed an 8-month recovery period in order to institute a recovery period that ends March 31, the recovery period term the Commission approved in Docket 15-808.[75] The Department does not support this proposal because of the Prorated ADIT issue discussed earlier (in Section III.D.2); rather the Department recommends that the approved rate become effective no soon than January 1, 2019. Consistent with IRS regulations, the Commission-approved resolution to the prorated ADIT issue in riders is to set recovery periods post test period; this approach has developed since the Commission's decision in Docket 15-808. Xcel's current 2017 GUIC Rider approved by the Commission was designed to collect the outstanding revenue requirement amount at the time of its implementation ($14.6 million), over a 12-month period, post test year.[76] Therefore, consistent with the Commission's decision in Xcel's most recent GUIC petition, the Department recommends a 12-month recovery period, effective no sooner than January 1, 2019.

The Department is aware that a January 2019 implementation would cause the 2017 GUIC recovery and the 2018 GUIC recovery rates to overlap for two months (January 2019 – February 2019). However, the 2018 GUIC Rider designed to collect revenue requirements over a 12-month period, as compared to an 8-month timeframe proposed by Xcel, would reduce the severity of bill impact from such an overlap. The following table shows illustrative Class Factors if 2018 GUIC Rider began in January 2019 and were collected over a 12-month period.

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[75] Commission Order issued August 18, 2016 in Docket G002/M-15-808.
[76] See Xcel's Compliance filed on February 20, 2018 in Docket G002/M-16-891.

Table 7. Xcel Proposed Class Factors for 8-month timeline versus Department calculated rates for 12-month timeline.[77]

Rate Group	Xcel Proposed Class Factors, 8-month timeline (Aug 1, 2018-February 28, 2019)	Department Illustrative Class Factors, 12-Month timeline (Jan 1, 2019-Dec 31, 2019)
Residential	0.053784	0.045699
Commercial Firm	0.030490	0.025679
Commercial Demand Billed	0.025143	0.01894
Interruptible	0.018265	0.014159
Transportation	0.006870	0.003968

3. Tracker Balance Carrying Charge

In its initial filing of this docket, Xcel proposed that the then-pending 2017 GUIC Rider be stepped up for a limited time period (January 2018 – March 2018) to mitigate the under collected tracker balance; alternatively, Xcel requested implementation of a carrying charge, applied to the GUIC Rider carryover balance. Since the filing of this *Petition*, the Commission heard and approved the 2017 GUIC Rider with modifications,[78] requiring the rider rate to be set to recover costs over a 12-month period, with no carrying charge. The Department does not support implementing a carrying charge because the GUIC Rider mechanism is an optional, extraordinary rate tool, which permits utilities to begin recovery of eligible costs sooner than its next general rate case. The Department recommends no tracker balance carrying charge.

G. TARIFF SHEET AND CUSTOMER NOTICE

In Xcel's Attachment R to its *Petition*, the Company provided both clean and redline formats of its Tariff Sheet No 5-64. Xcel updated the tariff to reflect the combined values of the 2017 and 2018 GUIC Riders. If the Commission modifies the proposed revenue requirement or recovery period, then the Department recommends that the Commission require Xcel to make a compliance filing showing the final Class Factors, and all related tariff changes, within ten days of the date of the order. In addition, should the Commission approve a 2018 GUIC Rider effective period that overlaps temporarily with the current 2017 GUIC Rider, then the Commission should require Xcel to make a second compliance filing showing the Class Factors in effect March 1, 2019, with all related tariff changes, within ten days of the rate change. A subsequent customer billing message should be required and included on first bill with which the change in rate applies.

[77] Department-calculated rates use the Company-provided expenditures and sales forecast, both of which the Department recommends changes to. Therefore, these rates do not reflect the Department's final proposed rates.
[78] Commission Order issued February 8, 2018 in Docket G002/M-16-891.

Xcel noted that it will provide notice to customers regarding the 2017/2018 GUIC Rider in their monthly gas bills.[79] The following is the Company's proposed language to be included as a notice on customers' bills the month that the 2017/2018 GUIC Rider is implemented:

> This month's Resource Adjustment includes an updated Gas Utility Infrastructure Cost Adjustment (GUIC), which recovers the costs of assessments, modifications and replacement of natural gas facilities as required by state and federal safety programs. The GUIC portion of the Resource Adjustment is $X.XXXX per therm for Residential customers; $X.XXXX per therm for Commercial Firm customers; $X.XXXX for Commercial Demand Billed customers; $X.XXXX per therm for Interruptible customers; and $X.XXXX per therm for Transportation customers.

Xcel noted in its *Petition* that the Company will work with the Department and Commission Staff if there are any suggestions to modify this notice. The Department concludes that the Company's customer notice proposed is the same language used by Xcel in Docket 16-891 and as approved by the Commission in its August 18, 2016 Order in Docket 15-808.

H. PERFORMANCE METRICS

In Docket 15-808, the Commission required Xcel to develop performance metrics and specifically ordered that,

> Xcel shall develop metrics to measure the appropriateness of GUIC expenditures, to be included in future GUIC Rider filings, and provide stakeholders the opportunity for meaningful involvement. Each metric should include a reconciliation to the pertinent TIMP/DIMP rules, and/or if not tied to TIMP/DIMP requirement, the Company must identify what goal, benefit, and/or requirement it addresses.

In Docket 16-891, the Commission order acknowledged that Xcel's proposed metrics were a helpful starting point and thus ordered:

> Xcel shall continue to discuss with other parties, including the Department and the OAG, proposed performance metrics and ongoing evaluation of reporting requirements in future GIUC proceedings.

[79] *Petition*, Pages 34 and 35.

The information the Company provided in Attachment T to its initial filing is responsive to the Commission's prior GUIC orders. Table 8 below summarizes Xcel's proposed GUIC Metrics, results and conclusion as follows:

Table 8

Program	Metric	Measurement	Result	Conclusion
DIMP	Leak Rate by Vintage and Pipe Type	Monitor the impact of renewal efforts on leakage rates. Selection of higher-risk pipe segments will lower leakage rates over time.	Trending down since 2011 (Figure 2 of Attch. T, coated steel pipe)	3-Yr leak survey cycle contributes to Year-to-year variations
	Poor Performing main Replacement Unit Cost	Monitor unit costs greater than one standard deviation above the mean to ensure variances are understood and reasonable.	One project in 2016 had unit cost > one-stndrd deviation (Dwntwn StP)	Unit costs may vary for differences in soil, paving, traffic control and permit needs.
	Poor Performing Service Replacements Unit Cost	Monitor unit costs greater than one standard deviation above the mean to ensure variances are understood and reasonable.	Nine projects in 2016 were ± one-stndrd deviation	Unit cost variance attributed to svc Line length differences and opportunity to coordinate w/ city-planned projects, which reduces restoration costs
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.	22 repairs in 2013. None repaired in years 2014-2016 (Figure 5 of Attch. T)	Number of repairs expected to vary year-to-year as different pipelines are inspected.
	Actual vs. Estimated Cost Variance Explanations for Capital Projects	Monitor cost variances to ensure variance are understood and reasonable.	Actual costs approximated estimates (Table 4, Attch. T, incl. footnotes 1,2)	Variances attributed to schedule delays, excess dewatering of site, lower contract labor cost.

The Department reviewed the results of Xcel's metrics and generally concludes they are reasonable, with one exception. For the DIMP Poor Performing Main Unit Cost metric, one project stood well apart from all the others in terms of its per foot unit cost, yet Xcel included its costs when calculating the standard deviation threshold.[80] Including the outlier project caused only one project, the outlier itself (*i.e*., the downtown St. Paul project) to appear to be the only project having a cost deviation beyond the normal range. Xcel Gas could have excluded the outlier project in its statistical calculations, and if it had done so, there would have been six additional projects that would require further examination of their cost variances. The Department requests that in its reply comments, Xcel provide an evaluation of those additional six projects that have unit cost variances that exceed one standard deviation calculated without the outlier Downtown St. Paul project unit costs.

IV. DEPARTMENT REPLY TO XCEL ENERGY'S MAY 29, 2018 SUPPLEMENTAL COMMENTS ON GUIC RIDER PETITION AND DEPRECIATION IMPACTS FROM XCEL'S FIVE-YEAR STUDY DOCKET NO. E,G002/D-17-581

A. COMMISSION NOTICE

The Commission Notice issued on May 2, 2018, requested comments related to Xcel Gas' $6.8 million reduction in annual depreciation expense, starting in 2018, resulting from its depreciation revisions approved in Docket No. E,G002/D-17-581. The notice identified the topics open for discussion as follows:

- Should the Commission address the $6.8 million decrease in depreciation expense discussed in Xcel Energy's five-year depreciation study (Docket No. E,G-002/D-17-581) in Xcel Energy's Gas Utility Infrastructure Cost (GUIC) rider petition, in this docket?
- If so, how should the Commission address the decrease in depreciation expense (e.g. with a corresponding adjustment) in the GUIC petition? If not, why not?
- How should the Commission handle similar issues in the future?
- Are there other issues or concerns related to this matter?

B. XCEL ENERGY'S SUPPLEMENTAL COMMENTS

Xcel Energy filed comments on May, 29, 2018 to discuss whether to reflect Xcel Gas' $6.8 million reduction in annual depreciation expense in its GUIC Rider. Xcel stated it fully intends to incorporate the new depreciation rates for GUIC projects in the 2018 GUIC Rider revenue requirements, estimating the impact to be a $540,000 reduction. However, Xcel argues against the inclusion of the remaining annual depreciation expense reduction, which stems from non-GUIC capital, because it would be inappropriate and would violate the Commission's policy against single-issue ratemaking. Xcel posits that the proper venue to incorporate the non-GUIC depreciation changes would be in a future rate case.

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[80] The Downtown St. Paul project unit cost exceeded $325 per foot, whereas all other measured activities were less than $100 per foot.

Xcel Gas' last rate case set general rates based on a 2010 test year.[81] Xcel argues that since then it has experienced various cost increases unrelated to GUIC projects, which are not factored into its base rates. Therefore, Xcel concluded that it is not appropriate to isolate this single expense decrease outside of a rate case without consideration given to all of the cost changes over these past eight years. Xcel also pointed out, as illustrated in Xcel's Table 1 to its May 29 supplemental comments, that its annual depreciation expense has increased by nearly $6.9 million from non-GUIC capital investments alone, which outstrips the decrease approved in Docket 17-581.

C. DEPARTMENT'S REPLY COMMENTS

The Department concluded that the GUIC Rider should not incorporate the study's impact on the non-GUIC projects depreciation expense because doing so would fragment non-GUIC asset recovery, would be single issue ratemaking, and appears to extend beyond the scope of the GUIC statute.

1. Fragment Asset Recovery

In regulated utility ratemaking, for its plant investments, utilities typically are authorized to earn a *return on* their investments as well as a *return of* their investment. Despite the fact that the *return on and return of* dollars represent two types of costs, these costs are linked and are tied to a common item. (The accumulated "return of" dollars reduce the principal on which the "return on" amount is determined.) In the Department's view, to update a GUIC Rider rate to account for a dollar change in "return of" the non-GUIC common asset without regard to any change in the asset investment-to-date and without updating a tariff rate for any impact such change has on the "return on" dollars, would not be fair or reasonable. Further, to carve out a portion of an asset's particular cost element for cost recovery, in an irregular manner that causes the asset's cost element to be reflected within multiple rate mechanisms established at different points in time, would complicate rate review and regulatory oversight.

2. Single Issue Ratemaking

The concept of a test year is to establish just and reasonable base rates by reviewing a utility's entire operations at a normal operating level. It is not unusual that from year-to-year costs, sales volumes, or customer counts may vary, either up or down. Nor is it unusual that in a capital-intensive industry, depreciation expense is a material cost. Even so, to include in the GUIC rider a change in one ordinary base rate cost that occurs many years after a rate case, which is not a product of the rider-based activity, and without consideration of other inputs that established the base rate, would disregard the fact that the test-year's purpose and

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

function is to set representative and reasonable rates. Therefore, the Department concludes that to consider inclusion of Xcel Gas' annual depreciation expense changes unrelated to the GUIC projects would be single-issue ratemaking and should not be included in this rider. However, as discussed in Section III.D.1.b.ii previously, the Department recommends that the Commission require Xcel Gas' to incorporate the newly approved depreciation rates when determining the depreciation expense for GUIC Rider projects.

Putting the single issue ratemaking aside, the Department reviewed and compared Xcel Gas' 2017 normalized operations shown in its jurisdictional annual reports, to its approved 2010 test year (See Table 9 below).

Table 9

Comparison of Xcel Gas Rate Case 2010 Test Year to Reported 2017 Operations
$000s

Line No.		**2010 Test Yr** 1/	**2017 JAR** 2/	***Change from 2010-to-2017*** (col. B - A)	**or % Δ**	**2017 GUIC** 3/	***Change without GUIC $*** (col. C - D)
		A	B	C	C.1	D	E
1	Plant in Service (Average)	937,311	1,222,545	*285,234*	*30%*	92,656	*192,579*
2	Depreciation Expense	32,684	41,845	*9,161*	*28%*	2,265	*6,896*
3	Overall Average Rate Base	438,315	533,264	*94,949*	*22%*	81,425	*13,524*
4	Operating Income + AFUDC	36,292	37,398	*1,106*	*3%*	5,697	*(4,591)*
5	Overall Rate of Return	8.28%	7.01%			7.02%	
6	Return on Equity	10.09%	9.16%			9.04%	
	Source:						
	1/ Docket No. G002/GR-09-1153						
	2/ Docket No. E,G999/PR-18-04						
	3/ Docket No. G002/M-17-787 Supplement Filing; Rate Base is averaged monthly - value is the 13-mo. average.						

The Department confirmed Xcel's assessment that its 2017 annual depreciation expense increase over the amount included in its last rate case outstrips the approved reduction (Table 9, Line 2, columns C and E). In addition, Xcel Gas' plant in service has increased by $285.2 million with GUIC projects included, or $192.6 million with GUIC projects excluded (Table 9, Line 1, columns C and E). From this information, one could conclude that Xcel has continued to invest in its system since its last rate case outside of rider incentives.[82] Also noted is that Xcel

[82] In addition to the GUIC Rider, Xcel Gas has a SEP Rider which recovers infrastructure investments which sums to a reported $13.7 million plant-in-service at 2017 year-end (Docket G002/18-184, Schedule D2).

Gas' reports that its operating income, while unaudited by regulators, increased by $1.1 million with GUIC rider revenue, but when GUIC rider revenue is removed, operating revenue decreased by $4.6 million (Table 9, Line 4, columns C and E). Despite the smaller growth in operating income relative to its reported change in plant investment, Xcel Gas calculated a normalized return on equity of 9.16 percent for 2017; this reported level is due in part to lower debt costs.

3. Scope of the GUIC Statute

The Department believes that inclusion of changes in depreciation expense stemming from non-GUIC operations would capture changes that are beyond the rider's statutory framework. The Department also notes that the non-GUIC cost changes, in part, could be linked to or are a product of betterments and/or connecting new customers; costs related to these reasons are specifically to be excluded from this rider. In fact, Xcel Gas' average number of customers has grown by approximately 21,000 since its last rate case.[83] Therefore, inclusion of Xcel Gas' overall annual depreciation expense does not appear to be supported by Minn. Stat. § 216B. 1635. The following are parts of the statute that led the Department to its conclusion.

Section 216B.1635, Subd. 2 states in part:

> A public utility submitting a petition to recover gas infrastructure costs under this section must submit to the commission, the department, and interested parties a gas infrastructure project plan report and a petition for rate recovery of only incremental costs associated with projects under subdivision 1, paragraph (c).

The referenced Section 216B.1635, Subd. 1, paragraph (c), reads:

> (c) "Gas utility projects" means:
> (1) replacement of natural gas facilities located in the public right-of-way required by the construction or improvement of a highway, road, street, public building, or other public work by or on behalf of the United States, the state of Minnesota, or a political subdivision; and (2) replacement or modification of existing natural gas facilities, including surveys, assessments, reassessment, and other work necessary to determine the need for replacement or modification of existing infrastructure that is required by a federal or state agency.

[83] Average number of customers included in Xcel Gas' 2010 test year totaled 434,203, whereas the 2017 JAR report (Tab 38) reported a total of 455,430 average number of customers; 455,430 – 434,203 = 21,227 increase, or approximately a 4.9% increase.

And Section 216B.1635, Subd. 4 reads:

> Subd. 4. Cost recovery petition for utility's facilities.
> Notwithstanding any other provision of this chapter, the commission may approve a rate schedule for the automatic annual adjustment of charges for gas utility infrastructure costs net of revenues under this section

Section 216B.1635, Subd 1(b) provides the definition of gas utility infrastructure costs, which reads:

> (b) "Gas utility infrastructure costs" or "GUIC" means costs incurred in gas utility projects that:
> (1) do not serve to increase revenues by directly connecting the infrastructure replacement to new customers;
> (2) are in service but were not included in the gas utility's rate base in its most recent general rate case, or are planned to be in service during the period covered by the report submitted under subdivision 2, but in no case longer than the one-year forecast period in the report; and
> (3) do not constitute a betterment, unless the betterment is based on requirements by a political subdivision or a federal or state agency, as evidenced by specific documentation, an order, or other similar requirement from the government entity requiring the replacement or modification of infrastructure.

Nowhere does the statute refer to non-GUIC costs; as a result, the Department concludes that it would not be appropriate to include changes in non-GUIC costs in the GUIC rider.

V. CONCLUSIONS AND RECOMMENDATIONS

Based on its review, the Department concludes that Xcel's continued recovery of the GUIC Rider is reasonable. However, the Department recommends modifications to Xcel's proposed 2018 GUIC Rider.

The Department recommends that Xcel provide the following in Reply Comments:

- An updated forecast, without the historical monthly adjustment;
- Clarification as to why forecasted sales for 2018 and 2019 are so much lower than actual sales reported in the GJAR for 2016 and 2017.
- The reporting required by Minn. Stat. § 216B.1635, Subd. 4 (2) (iii);

- Clarify: 1) the extent to which the additional 207 miles of intermediate pressure pipelines are subject to MAOP regulations (49 CFR 192.619), and 2) any updates or other information on these lines that may be helpful;
- Identify all completed and proposed GUIC projects that change the classification of the gas pipeline/plant system (i.e., from transmission-to-distribution or vice versa), explaining the characteristics that caused the reclassification. The Reply Comments should also detail the cost allocation treatment of that gas system infrastructure and its associated O&M costs between Minnesota and North Dakota before and after such classification change; Likewise, identify all NSP gas system integrity management projects undertaken or planned in North Dakota that affect the cost allocation treatment of that gas system infrastructure and/or associated O&M between North Dakota and Minnesota; and
- For the DIMP Poor Performing Main Unit Cost performance metric, provide an analysis of costs for each of the projects that have unit cost variances which exceed one standard deviation calculated without the outlier Downtown St. Paul project unit costs.

The Department also recommends that the Commission:

- direct the Company to include the reporting required by Minn. Stat. § 216B.1635, Subd. 4 (2) (iii) in future GUIC rider petitions;
- require Xcel to include only incremental rate base amounts in its GUIC rider rate base; Alternatively, if Xcel Gas cannot reasonably determine the remaining book value of existing plant included in base rates since removed or retired due to GUIC projects, then direct Xcel Gas to do away with the adjustments to the GUIC rider accumulated depreciation reserve attributed to the removal costs of the old plant;
- require the Company to recalculate the incremental depreciation expense amount by accounting for the depreciation expense amounts included in base rates relevant to the plant assets replaced by (or retired through) the GUIC projects included in this rider. Any previously overstated revenue requirements should be credited back to ratepayers;
- Direct the Company to incorporate and apply the Commission-decided depreciation factors in Docket E,G002/D-17-581, when calculating GUIC-projects' depreciation in this *Petition*;
- require Xcel to recalculate the incremental property tax expense amount for all GUIC years by adjusting original cost of GUIC projects by the original cost of plant assets replaced by (or retired through) the GUIC projects in each year, prior to applying Xcel's calculated property tax rate. Any overstated revenue requirements should be credited back to ratepayers;
- Maintain Xcel Gas' rider authorized Rate of Return at 7.02%;

- direct that the implementation of the 2018 GUIC Rider to be effective no sooner than January 1, 2019 to recovery the 2018 GUIC Rider revenue requirements over a 12-month recovery period;
- Consider limiting the "return on" the capital costs incurred to remediate the system's MAOP data gaps, to Xcel Gas' long-term debt costs;
- For the TIMP Island Line South Project, direct Xcel to exclude the $0.6 million estimated costs of the ILI assessments to be performed on the Island Line South pipeline designated to be replaced and direct Xcel to remove the $1.5 million cost overruns from the GUIC rider recovery;
- require that the Langdon Line project amount includable in the GUIC rider rate base be adjusted and reduced by the project's cost differential between use of a 12-inch and an 8-inch pipe, should the Company elect to use a 12-inch diameter pipe instead of an 8-inch diameter pipe. Xcel estimated this cost differential to be approximately $3.6 million;
- Direct Xcel to exclude $420,000 of the H005 project costs be excluded from GUIC recovery rider;
- Direct Xcel to remove $85,000 in costs incurred on low-risk infrastructure replacement costs that were not required by civic/public work requirements, nor required by government regulations;
- Determine no carrying charge on the GUIC tracker balance;
- Direct the Company to remove from the GUIC Rider $8,276,882 in capital costs not already removed, unless the Company can adequately demonstrate that these costs are Minnesota-specific and incremental to costs captured in base rates;
- Direct the Company to use a jurisdictional allocator for all costs identified in Attachment 20, Table 3, unless the Company can provide invoices and work orders related to all of these charges;
- Direct the Company to remove the work that is not Minnesota-specific, as identified by the Company in response to IR 62;
- Require Xcel, in future GUIC filings, to present historical and projected GUIC revenue requirements, rates, and recoveries within a single tracker for each year;
- Require Xcel to make a compliance filing showing the final rate-adjustment factors and all related tariff changes, within ten days of the date of the *Order*;
- In the event the 2017 GUIC rate and 2018 GUIC rate overlap, require Xcel to make a second compliance filing showing the final rate-adjustment factors in effect as of March 1, 2019, within 10 days of the rate change; in addition, require Xcel to include the Commission-approved billing message on customers' first bills to which the new rate applies.

/ja

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Xcel Energy			
Docket No.:	G002/M-17-787		
Response To:	MN Department of Commerce	Information Request No.	51
Requestor:	Dorothy Morrissey, Danielle Winner		
Date Received:	April 2, 2018		

<u>Question:</u>

Topic: Bill Impacts
Reference(s): Attachment Q in March 27, 2018 Supplement

Request:

A. For each rate class, please provide a comparison of the Company's Minnesota-customers average usage over a continuous 12-month period and the average usage during the 7-month period August through February.

B. Using the same average customer usage during the 7-month period August through February (Part A), for each rate class please provide the average bill impact during this 7-month period, assuming the Company's proposal to overlap the collections of its 2017 and 2018 GUIC revenue requirement collections is approved.

C. Please provide the bill impact to each customer class following the end of the proposed overlapped rate-period, (1) compared to the rates proposed to be in effect during the 7-month period August through February, and (2) compared to the rates in effect prior to the 7-month period.

<u>Response:</u>

A. Please see the following table for the Company's Minnesota-customers average monthly usage over the 12-month period August 2018 through July 2019 and the average monthly usage over the 7-month period August through February:

Minnesota Customers Average Monthly Use per Customer (Therms)

Rate Class	12 Months Aug18-Jul19	7 Months Aug18-Feb19
Residential	70	87
Commercial Firm	480	587
Commercial Dmd Bill	16,990	18,707
Interruptible	22,775	25,752
Transport	663,538	636,728

B. The following table shows the average monthly bill impact during the 7-month overlap period (August 2018 through February 2019):

Average Monthly Bill Impact

Rate Class	Aug18-Feb19 Proposed Factor	Aug18-Feb19 Avg Usage (Therms)	Avg Bill Impact
Residential	$0.081419	87	$7.09
Commercial Firm	$0.045569	587	$26.76
Commercial Dmd Bill	$0.036475	18,707	$682.32
Interruptible	$0.026379	25,752	$679.32
Transport	$0.010157	636,728	$6,467.11

C. Please see the following tables for a comparison of the period prior (April 2018 through July 2018), to the proposed overlapped period (August 2018 through February 2019), and the period after the proposed overlapped period (March 2019).

Proposed Factors ($/Therm)

Rate Class	(Apr18-Feb19) 2017 Recovery (A)	(Aug18-Mar19) 2018 Recovery (B)	(Aug18-Feb19) Combined (C)
Residential	$0.027634	$0.053784	$0.081419
Commercial Firm	$0.015080	$0.030490	$0.045569
Commercial Dmd Bill	$0.011332	$0.025143	$0.036475
Interruptible	$0.008114	$0.018265	$0.026379
Transport	$0.003287	$0.006870	$0.010157

Average Monthly Use per Customer (UPC) in Therms

Rate Class	Apr18-Jul18 (D)	Aug18-Feb19 (E)	Mar19 (F)
Residential	32	87	108
Commercial Firm	224	587	754
Commercial Dmd Bill	12,692	18,707	22,101
Interruptible	15,670	25,752	29,284
Transport	706,749	636,728	484,564

Average Monthly Bill Impact (Proposed Factors * UPC)

	Apr18-Jul18	Aug18-Feb19			Mar19
	2017 Recovery	2017 Recovery	2018 Recovery	Combined Recovery	2018 Recovery
Rate Class	(A*D)	(A*E)	(B*E)	(C*E)	(B*F)
Residential	$0.89	$2.41	$4.68	$7.09	$5.80
Commercial Firm	$3.38	$8.86	$17.90	$26.76	$22.99
Commercial Dmd Bill	$143.83	$211.99	$470.33	$682.32	$555.68
Interruptible	$127.15	$208.95	$470.36	$679.32	$534.88
Transport	$2,323.15	$2,092.98	$4,374.12	$6,467.11	$3,328.80

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Xcel Energy
Docket No.: G002/M-17-787
Response To: MN Department of Commerce Information Request No. 55
Requestor: Dorothy Morrissey, Danielle Winner
Date Received: April 5, 2018

Question:

Topic: TIMP Programmatic Replacement and MAOP Remediation
Reference(s): Response to DOC IR No. 19

Request:

A. Regarding response to Part A of DOC IR No. 19, please explain why the Company has incomplete maximum allowable operation pressure (MAOP) records for 21 percent of its gas transmission miles.

B. Please identify both the short- and the long-term remediation actions that the Company will undertake to satisfy the MAOP pipeline safety requirements for the 21 percent of transmission pipelines identified as incomplete and provide the timeframe and total projected costs to do so.

Response:

A. Prior to the MAOP Remediation Advisory Bulletin[1] issued in 2012, the requirement that records be traceable, verifiable and complete (TVC) did not exist, and some of the Company's MAOP records do not meet the new criteria. Additionally, some of the Company's gas transmission pipelines were constructed prior to the enactment of Federal Pipeline Safety Rules in 1970, which specified the requirements for establishing MAOP.

B. The Company evaluates gas transmission pipelines for TIMP MAOP risk per the quantitative risk assessment methodology on page 15 of Petition Attachment C2. Those MAOP projects identified as medium and high risk, which requires remediation, are those lacking TVC records that demonstrate compliance with test pressure requirements established in 49CFR Part 192.619(a)(2). Pipelines that do not have TVC records of pipe material but have satisfactory test pressure records are evaluated as low risk and do not require remediation under current regulatory requirements. The table below shows the capital projects the Company has identified for remediation.

TIMP MAOP Pipeline Project	Approximate Project Length	Timeframe - Years
County Road B (NSP to Rice)	6.5 miles	2018-2020
East County Line (30-inch Maplewood Propane to North St. Paul)	1.4 miles	2018-2019
East County Line (30-inch SSP to RR Tracks)	0.6 miles	2017-2018
Island Line North Valve Header	0.05 miles	2023-2025

The Company has identified that the TIMP MAOP risk score shown on Page 15 of Petition Attachment C2 for the Crossover Pipeline Project between Upper 55 to South St. Paul Regulator Station was not correct. The assessment incorrectly identified that the Crossover Line lacked a TVC pressure test. As a result, the risk score of 9.6 shown is not correct and should instead be 1.6, which is considered Low Risk. This 12-inch gas transmission pipeline was installed in 1946 prior to the enactment of Federal Pipeline Safety regulations, and the Company does not have records that the pipeline was pressure tested prior to being placed into service. However, in preparing the risk score for this project, Company engineers failed to take account of a pressure test that was completed in 2015. We still consider this an important project and plan to complete it as a part of our normal capital work. However, because of the revised low risk score, the Company will not pursue recovery of this project as part of the GUIC.

Removing the Crossover Pipeline Project from the GUIC request will result in decreases of $4,140 in the 2017 GUIC revenue requirement and $100,094 in the 2018 GUIC revenue requirement. Rather than recalculating the already approved rate factors for the 2017 GUIC revenue requirement, we propose to reduce our 2018 GUIC revenue requirement by $104,234 to account for the impact from both 2017 and 2018. We intend to file update schedules reflecting this adjustment in our Reply Comments in this docket.

The Company has reviewed all risk scores reported in Petition Attachments C2 and D2(a) and found the errors described below:

i. Calculation errors exist in the DIMP Intermediate Pressure (IP) Line Replacements Project Risk on Attachment D2(a), page 6. The corrected values are shown in the table below. Company Engineers incorrectly added scores for corrosion, third-party damage, and other leak factors instead of using only the maximum score. To illustrate, the corrected score for the Langdon Line project is:

Risk Score (G) =
Likelihood of Failure
x Consequence of Failure (F = 3)

Likelihood of Failure =
Mechanical Joint Risk Factor (A = 2)
+ Manufacturing/Construction Risk Factor (B = 2)
+ Maximum Score of:
Corrosion Risk Factor (C = 1),
3rd Party Damage Risk Factor (D = 1),
Other Leak History Factor (E = 0)

Thus, Risk Score = (2 + 2 + 1) * 3 = 15

Project	A Mechanical Joint	B Manufacturing / Construction Defect	C Corrosion	D 3rd Party Damage	E Other Leak History	F Consequence	G Risk Score	Project Classification
Colby Lake Lateral	0	2	1	1	1	3	~~15~~ 9	~~High~~ Medium
H005 – Lexington to Snelling	2	2	1	1	1	3	~~21~~ 15	High
Langdon Line (TBS to Ashland)	2	2	1	1	0	3	~~18~~ 15	High

ii. The risk level reported for DIMP Sewer and Gas Line Conflict projects on Petition Attachment D2(a), page 14 of 22 are reported as High Risk. These projects will also include work near residential single family structures and thus should be more accurately described as a mixture of medium and high risk as shown in the corrected table below:

Polygon ID	City	State	Project	Estimated Service Count	Risk Scores	Risk Level
372455262	Roseville	MN	County Rd C2 W and Western Ave	784	~~6~~ 3	~~High~~ Medium 3
359596126	Vadnais Heights	MN	Berwood and Arcade	1168	~~6~~ 3	~~High~~ Medium 3
372455266	Faribault	MN	8th St and 4th Ave	969	~~6~~ 3	~~High~~ Medium 3
372455270	Sauk Rapids	MN	11th St N and 9th St N	869	~~6~~ 2-	~~High~~ Medium 3
372455278	Cottage Grove	MN	80th St S and Hwy 61	3619	~~6~~ 3	~~High~~ Medium 3
Total Inspections				*7,408		

The corrected scores shown in the tables above remain in the Medium classification. These errors do not have any material impact on our proposal, as both high and medium risk projects are included as a part of the GUIC.

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[1] On May 7, 2012, the Pipeline and Hazardous Materials Safety Administration (PHMSA) issued an Advisory Bulletin to clarify the record verification requirements for establishing Maximum Allowable Operating Pressure (MAOP) for natural gas pipelines. See http://www.gpo.gov/fdsys/pkg/FR-2012-05-07/pdf/2012-10866.pdf.

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Xcel Energy
Docket No.: G002/M-17-787
Response To: MN Department of Commerce Information Request No. 14
Requestors: Dorothy Morrissey, Danielle Winner
Date Received: January 30, 2018

Question:

Topic: TIMP Revenue Requirements
Reference(s): Attachment F

A. Please provide an electronic copy of Attachment F with formulae intact.

B. Please reference the current income tax calculation. Please explain what "CPI-Tax Interest (If Applicable)" is and explain the basis for its inclusion.

C. Please explain how the "deferred taxes" amount was computed and explain why its value remains constant for each month within a calendar year.

D. Regarding notes to TIMP Project Costs tables found on pages 4, 15 and 22 of Attachment C: Please identify the amount of RWIP (removal work in progress) costs included in Attachment F "Plant in Service" amounts.

Response:

A. Please see Attachment A to this response for an electronic copy of Attachment F to the Petition, with formulae intact.

B. CPI stands for Construction Period Interest, which is capitalized and included in the tax basis used for tax depreciation of property only. It is sometimes also referred to as "Avoided Tax Interest." It is not reflected in the plant in-service or construction work in progress amounts.

IRS Publication 535 offers the following guidance in regards to CPI:

- "Under the uniform capitalization rules, you generally must capitalize interest on debt equal to your expenditures to produce real property or certain tangible personal property.
- "Treat capitalized interest as a cost of the property produced. You recover your interest when you sell or use the property…If the property is used in your trade or business, recover capitalized interest through an adjustment to basis, depreciation, amortization or other method."

It is reasonable to include an avoided tax interest component related to the computation of taxable income because it represents an imputed interest that is considered taxable income during the construction period of an asset pursuant to Internal Revenue Service rules. For that reason, we have consistently included an avoided tax interest component in our past rider filings.

Avoided tax interest is computed by applying an imputed IRS-defined interest rate which is calculated based on the "avoided cost method" to the average monthly CWIP balance during the construction period of an asset. Under the "avoided cost method," any interest that theoretically would have been avoided if accumulated construction expenditures had been used to repay or reduce outstanding debt must be capitalized and included in both taxable income and the tax depreciable basis of an asset. All amounts added to taxable income are also added to the tax depreciable basis of the asset and deducted through the computation of tax depreciation

C. The "deferred taxes" amount is the difference between book depreciation and tax depreciation multiplied by the corporate composite tax rate. This is an annual calculation spread evenly across the previous 12 months. Thus, the deferred tax amount will not change by month throughout the year. We note that monthly amounts for actuals are not fully known until the full year completes, even though other components of monthly actuals can be known as each given month is recorded.

D. RWIP is not included in Plant in Service amounts but is reflected in Net Plant. RWIP expenditures close against accumulated book depreciation reserve and affect rate base by changing the accumulated book depreciation reserve. Positive RWIP balances decrease the accumulated book depreciation reserve.

Below is a summary of the CWIP and RWIP included in TIMP Net Plant.

($ millions)	**2016**	**2017**	**2018**
TIMP			
CWIP *(Attachment E)*	$18.75	$8.93	$8.72
RWIP	$2.96	$0.38	$0.31
Total Capital Expenditures	**$21.71**	**$9.31**	**$9.03**
Petition Attachment C Reference	*Page 22*	*Page 15*	*Page 4*

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Telephone: 612-337-2076
Date: February 9, 2018

Northern States Power Company

TIMP - Capital Revenue Requirements	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Total
Rate Base													
CWIP	-	-	-	-	-	-	-	-	-	-	-	-	-
Plant In-Service	41,002,201	41,224,699	41,221,031	41,358,584	41,362,685	48,647,724	47,049,533	52,672,931	54,706,235	52,527,236	55,163,535	59,397,911	59,397,911
Less Accumulated Book Depreciation Reserve	(135,999)	(50,939)	34,589	120,256	206,070	296,627	396,067	493,430	605,136	716,688	828,720	946,473	946,473
Less Accumulated Deferred Taxes	3,463,723	3,642,527	3,821,330	4,000,134	4,178,937	4,357,740	4,536,544	4,715,347	4,894,151	5,072,954	5,251,757	5,430,561	5,430,561
End Of Month Rate Base	37,674,476	37,633,111	37,365,112	37,238,194	36,977,678	43,993,356	42,116,923	47,464,154	49,206,948	46,737,594	49,083,057	53,020,878	53,020,878
Average Rate Base (Prior Mo + Cur Month/2)	37,883,755	37,653,793	37,499,111	37,301,653	37,107,936	40,485,517	43,055,139	44,790,538	48,335,551	47,972,271	47,910,326	51,051,968	
Return on Rate Base													
Debt Return (Avg RB * Wtd Cost of Debt)	71,663	71,228	70,936	70,562	70,196	76,585	81,446	84,729	91,435	90,748	90,630	96,573	966,732
Equity Return (Avg RB * Wtd Cost of Equity)	159,743	158,773	158,121	157,289	156,472	170,714	181,549	188,867	203,815	202,283	202,022	215,269	2,154,917
Total Return on Rate Base	231,407	230,002	229,057	227,851	226,668	247,299	262,995	273,596	295,250	293,031	292,652	311,842	3,121,649
Income Statement Items													
AFUDC Pre-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-
Property Taxes	58,295	58,295	58,295	58,295	58,295	58,295	58,295	58,295	58,295	58,295	58,295	58,295	699,538
Book Depreciation	85,242	85,299	85,528	85,667	85,814	93,467	99,439	103,666	111,704	111,552	112,032	117,752	1,177,163
Deferred Taxes	178,803	178,803	178,803	178,803	178,803	178,803	178,803	178,803	178,803	178,803	178,803	178,803	2,145,641
Gross Up for Income Tax (see below)	92,641	90,891	87,981	76,831	82,003	106,734	113,703	130,633	136,871	(1,152,909)	1,073,114	(1,462,144)	(623,649)
Total Income Statement Expense	414,982	413,289	410,607	399,596	404,915	437,299	450,241	471,398	485,674	(804,259)	1,422,244	(1,107,293)	3,398,693
Total Revenue Requirement	**646,388**	**643,291**	**639,664**	**627,447**	**631,583**	**684,599**	**713,236**	**744,993**	**780,924**	**(511,228)**	**1,714,896**	**(795,451)**	**6,520,342**

Capital Structure													
Weighted Cost of Debt	2.27%												
Weighted Cost of Equity	5.06%												
Required Rate of Return	7.33%												
Current Income Tax Calculation													
Equity Return	159,743	158,773	158,121	157,289	156,472	170,714	181,549	188,867	203,815	202,283	202,022	215,269	2,154,917
Book Depreciation	85,242	85,299	85,528	85,667	85,814	93,467	99,439	103,666	111,704	111,552	112,032	117,752	1,177,163
Deferred Taxes	178,803	178,803	178,803	178,803	178,803	178,803	178,803	178,803	178,803	178,803	178,803	178,803	2,145,641
Less Tax Depreciation	292,496	294,064	298,157	314,373	309,691	299,354	309,528	299,258	315,276	2,145,430	(1,005,281)	2,595,461	6,467,808
Plus CPI-Tax Interest (If Applicable)	-	-	392	1,499	4,817	7,635	10,877	13,057	14,929	18,877	22,690	11,471	106,244
Total	131,292	128,812	124,688	108,885	116,215	151,265	161,141	185,135	193,976	(1,633,915)	1,520,828	(2,072,165)	(883,843)
Tax Rate (T/(1-T)	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611
Gross Up for Income Tax	92,641	90,891	87,981	76,831	82,003	106,734	113,703	130,633	136,871	(1,152,909)	1,073,114	(1,462,144)	(623,649)

TIMP - Capital Revenue Requirements	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Total
Rate Base													
CWIP	-	-	-	-	-	-	-	-	-	-	-	-	-
Plant In-Service	59,405,130	59,491,425	59,499,445	59,770,146	60,147,335	60,459,921	60,762,999	60,956,906	62,773,002	64,337,448	65,967,643	68,222,346	68,222,346
Less Accumulated Book Depreciation Reserve	1,067,185	1,187,967	1,308,815	1,429,952	1,551,664	1,673,922	1,796,636	1,915,747	(2,703,454)	(4,096,618)	(4,529,778)	(4,636,295)	(4,636,295)
Less Accumulated Deferred Taxes	5,540,657	5,650,753	5,760,850	5,870,946	5,981,042	6,091,138	6,201,235	6,311,331	6,421,427	6,531,523	6,641,620	6,751,716	6,751,716
End Of Month Rate Base	52,797,288	52,652,705	52,429,780	52,469,248	52,614,630	52,694,860	52,765,129	52,729,829	59,055,029	61,902,543	63,855,801	66,106,926	66,106,926
Average Rate Base (Prior Mo + Cur Month/2)	52,909,083	52,724,997	52,541,243	52,449,514	52,541,939	52,654,745	52,729,995	52,747,479	55,892,429	60,478,786	62,879,172	64,981,364	
Return on Rate Base													
Debt Return (Avg RB * Wtd Cost of Debt)	100,086	99,738	99,391	99,217	99,392	99,605	99,748	99,781	105,730	114,406	118,946	122,923	1,258,962
Equity Return (Avg RB * Wtd Cost of Equity)	220,014	219,248	218,484	218,103	218,487	218,956	219,269	219,342	232,419	251,491	261,473	270,214	2,767,499
Total Return on Rate Base	320,100	318,986	317,875	317,320	317,879	318,561	319,016	319,122	338,149	365,897	380,419	393,137	4,026,461
Income Statement Items													
AFUDC Pre-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-
Property Taxes	84,131	84,131	84,131	84,131	84,131	84,131	84,131	84,131	84,131	84,131	84,131	84,131	1,009,577
Book Depreciation	120,713	120,781	120,848	121,137	121,711	122,259	122,713	123,037	124,815	127,785	130,463	133,844	1,490,106
Deferred Taxes	110,096	110,096	110,096	110,096	110,096	110,096	110,096	110,096	110,096	110,096	110,096	110,096	1,321,155
Gross Up for Income Tax (see below)	51,010	33,139	62,311	76,346	55,426	47,398	4,845	(9,712)	56,764	73,900	84,461	94,302	630,189
Total Income Statement Expense	365,951	348,147	377,387	391,711	371,365	363,884	321,786	307,552	375,806	395,913	409,152	422,373	4,451,028
Total Revenue Requirement	**686,051**	**667,134**	**695,261**	**709,031**	**689,244**	**682,445**	**640,802**	**626,675**	**713,955**	**761,809**	**789,571**	**815,510**	**8,477,489**
Capital Structure													
Weighted Cost of Debt	2.27%												
Weighted Cost of Equity	4.99%												
Required Rate of Return	7.26%												
Current Income Tax Calculation													
Equity Return	220,014	219,248	218,484	218,103	218,487	218,956	219,269	219,342	232,419	251,491	261,473	270,214	2,767,499
Book Depreciation	120,713	120,781	120,848	121,137	121,711	122,259	122,713	123,037	124,815	127,785	130,463	133,844	1,490,106
Deferred Taxes	110,096	110,096	110,096	110,096	110,096	110,096	110,096	110,096	110,096	110,096	110,096	110,096	1,321,155
Less Tax Depreciation	381,646	405,544	363,714	343,963	374,676	386,874	447,841	469,417	390,576	389,584	387,771	385,156	4,726,762
Plus CPI-Tax Interest (If Applicable)	3,115	2,382	2,594	2,826	2,932	2,735	2,629	3,179	3,692	4,943	5,439	4,648	41,113
Total	72,292	46,964	88,308	108,199	78,551	67,173	6,867	(13,764)	80,446	104,731	119,699	133,645	893,111
Tax Rate (T/(1-T)	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611
Gross Up for Income Tax	51,010	33,139	62,311	76,346	55,426	47,398	4,845	(9,712)	56,764	73,900	84,461	94,302	630,189

Northern States Power Company

TIMP - Capital Revenue Requirements	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Total
Rate Base													
CWIP	-	-	-	-	-	-	-	-	-	-	-	-	-
Plant In-Service	68,723,162	69,018,830	69,246,855	69,526,617	69,832,343	70,330,018	70,969,160	71,964,909	75,047,409	76,017,765	76,810,635	77,452,797	77,452,797
Less Accumulated Book Depreciation Reserve	(4,609,154)	(4,525,570)	(4,417,708)	(4,299,168)	(4,175,772)	(4,055,584)	(3,939,973)	(3,832,383)	(3,722,671)	(3,607,184)	(3,482,830)	(3,458,473)	(3,458,473)
Less Accumulated Deferred Taxes	6,869,006	6,986,297	7,103,588	7,220,878	7,338,169	7,455,459	7,572,750	7,690,041	7,807,331	7,924,622	8,041,912	8,159,203	8,159,203
End Of Month Rate Base	66,463,310	66,558,103	66,560,976	66,604,906	66,669,946	66,930,142	67,336,383	68,107,252	70,962,749	71,700,328	72,251,553	72,752,068	72,752,068
Average Rate Base (Prior Mo + Cur Month/2)	66,285,118	66,510,707	66,559,539	66,582,941	66,637,426	66,800,044	67,133,263	67,721,818	69,535,000	71,331,538	71,975,940	72,501,810	
Return on Rate Base													
Debt Return (Avg RB * Wtd Cost of Debt)	125,389	125,816	125,908	125,953	126,056	126,363	126,994	128,107	131,537	134,935	136,154	137,149	1,550,363
Equity Return (Avg RB * Wtd Cost of Equity)	289,997	290,984	291,198	291,300	291,539	292,250	293,708	296,283	304,216	312,075	314,895	317,195	3,585,641
Total Return on Rate Base	415,387	416,800	417,106	417,253	417,595	418,614	420,702	424,390	435,753	447,011	451,049	454,345	5,136,004
Income Statement Items													
AFUDC Pre-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-
Property Taxes	96,630	96,630	96,630	96,630	96,630	96,630	96,630	96,630	96,630	96,630	96,630	96,630	1,159,565
Book Depreciation	136,184	136,693	137,028	137,352	137,726	138,239	138,966	140,010	143,459	146,891	148,017	148,934	1,689,498
Deferred Taxes	117,291	117,291	117,291	117,291	117,291	117,291	117,291	117,291	117,291	117,291	117,291	117,291	1,407,487
Gross Up for Income Tax (see below)	99,219	99,653	98,151	85,781	86,856	80,186	77,797	72,521	77,465	104,866	116,606	120,808	1,119,908
Total Income Statement Expense	449,324	450,266	449,099	437,054	438,503	432,347	430,684	426,452	434,845	465,678	478,544	483,663	5,376,458
Total Revenue Requirement	**864,711**	**867,067**	**866,206**	**854,307**	**856,098**	**850,960**	**851,385**	**850,842**	**870,598**	**912,689**	**929,593**	**938,007**	**10,512,463**
Capital Structure													
Weighted Cost of Debt	2.27%												
Weighted Cost of Equity	5.25%												
Required Rate of Return	7.52%												
Current Income Tax Calculation													
Equity Return	289,997	290,984	291,198	291,300	291,539	292,250	293,708	296,283	304,216	312,075	314,895	317,195	3,585,641
Book Depreciation	136,184	136,693	137,028	137,352	137,726	138,239	138,966	140,010	143,459	146,891	148,017	148,934	1,689,498
Deferred Taxes	117,291	117,291	117,291	117,291	117,291	117,291	117,291	117,291	117,291	117,291	117,291	117,291	1,407,487
Less Tax Depreciation	405,470	405,470	407,782	426,180	426,180	438,102	444,989	457,815	461,102	430,844	417,702	414,448	5,136,086
Plus CPI-Tax Interest (If Applicable)	2,612	1,731	1,366	1,806	2,718	3,963	5,280	7,009	5,923	3,204	2,754	2,238	40,605
Total	140,614	141,229	139,100	121,569	123,094	113,641	110,255	102,777	109,785	148,618	165,255	171,210	1,587,146
Tax Rate (T/(1-T)	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611
Gross Up for Income Tax	99,219	99,653	98,151	85,781	86,856	80,186	77,797	72,521	77,465	104,866	116,606	120,808	1,119,908

Northern States Power Company

TIMP - Capital Revenue Requirements	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Total
Rate Base													
CWIP	-	-	-	-	-	-	-	-	-	-	-	-	-
Plant In-Service	77,943,161	78,357,327	78,891,953	79,891,266	81,123,838	83,184,433	85,707,214	89,809,399	94,030,698	98,019,039	101,406,402	104,217,957	104,217,957
Less Accumulated Book Depreciation Reserve	(3,323,462)	(3,186,112)	(3,052,130)	(2,928,230)	(2,808,434)	(2,707,265)	(2,617,083)	(2,559,876)	(2,500,830)	(2,430,454)	(2,337,160)	(2,224,397)	(2,224,397)
Less Accumulated Deferred Taxes	8,329,445	8,499,688	8,669,930	8,840,173	9,010,415	9,180,658	9,350,900	9,521,143	9,691,385	9,861,627	10,031,870	10,202,112	10,202,112
End Of Month Rate Base	72,937,178	73,043,752	73,274,152	73,979,322	74,921,857	76,711,041	78,973,397	82,848,132	86,840,143	90,587,865	93,711,692	96,240,242	96,240,242
Average Rate Base (Prior Mo + Cur Month/2)	72,844,623	72,990,465	73,158,952	73,626,737	74,450,590	75,816,449	77,842,219	80,910,765	84,844,138	88,714,004	92,149,778	94,975,967	
Return on Rate Base													
Debt Return (Avg RB * Wtd Cost of Debt)	137,798	138,074	138,392	139,277	140,836	143,419	147,252	153,056	160,497	167,817	174,317	179,663	1,820,398
Equity Return (Avg RB * Wtd Cost of Equity)	318,695	319,333	320,070	322,117	325,721	331,697	340,560	353,985	371,193	388,124	403,155	415,520	4,210,171
Total Return on Rate Base	456,493	457,407	458,463	461,394	466,557	475,116	487,811	507,041	531,690	555,941	577,472	595,183	6,030,568
Income Statement Items													
AFUDC Pre-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-
Property Taxes	109,704	109,704	109,704	109,704	109,704	109,704	109,704	109,704	109,704	109,704	109,704	109,704	1,316,453
Book Depreciation	149,658	150,236	150,842	151,822	153,248	155,352	158,280	162,512	167,830	173,075	177,787	181,747	1,932,387
Deferred Taxes	170,242	170,242	170,242	170,242	170,242	170,242	170,242	170,242	170,242	170,242	170,242	170,242	2,042,909
Gross Up for Income Tax (see below)	79,173	79,786	74,018	64,194	68,493	50,364	55,085	27,773	66,475	92,882	127,054	146,199	931,497
Total Income Statement Expense	508,778	509,969	504,807	495,962	501,688	485,663	493,312	470,232	514,251	545,904	584,788	607,893	6,223,247
Total Revenue Requirement	**965,271**	**967,376**	**963,270**	**957,357**	**968,245**	**960,779**	**981,123**	**977,273**	**1,045,941**	**1,101,845**	**1,162,260**	**1,203,076**	**12,253,815**
Capital Structure													
Weighted Cost of Debt	2.27%												
Weighted Cost of Equity	5.25%												
Required Rate of Return	7.52%												
Current Income Tax Calculation													
Equity Return	318,695	319,333	320,070	322,117	325,721	331,697	340,560	353,985	371,193	388,124	403,155	415,520	4,210,171
Book Depreciation	149,658	150,236	150,842	151,822	153,248	155,352	158,280	162,512	167,830	173,075	177,787	181,747	1,932,387
Deferred Taxes	170,242	170,242	170,242	170,242	170,242	170,242	170,242	170,242	170,242	170,242	170,242	170,242	2,042,909
Less Tax Depreciation	528,241	528,241	537,947	556,097	556,097	592,027	599,127	659,627	629,377	613,727	583,401	570,591	6,954,501
Plus CPI-Tax Interest (If Applicable)	1,850	1,503	1,692	2,892	3,955	6,113	8,113	12,248	14,320	13,920	12,278	10,276	89,161
Total	112,205	113,074	104,900	90,976	97,069	71,377	78,068	39,360	94,209	131,634	180,062	207,195	1,320,128
Tax Rate (T/(1-T)	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611
Gross Up for Income Tax	79,173	79,786	74,018	64,194	68,493	50,364	55,085	27,773	66,475	92,882	127,054	146,199	931,497

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Xcel Energy
Docket No.: G002/M-17-787
Response To: MN Department of Commerce Information Request No. 41
Requestors: Dorothy Morrissey, Danielle Winner
Date Received: March 27, 2018

Question:

Topic: TIMP revenue requirements – Accumulated Depreciation
Reference(s): Attachment F

A. Pages 3: Please explain the reason the monthly Accumulated Depreciation reserve balance in 2018 has a debit balance.

B. Pages 2-3: Please provide a detailed explanation of the monthly change in the Accumulated Depreciation reserve balance for each month from August 2017 to December 2018.

Response:

A. Accumulated depreciation reserve balance in 2018 had a debit balance due to the closing of removal work in progress (RWIP) expenditures, resulting from RWIP closings being greater than the accumulated reserve balance for current GUIC projects. RWIP closings decrease the balance of accumulated depreciation, because an estimated cost of removal amount is factored in to the depreciation rate approved by the Commission in order to collect the cost to remove an asset while that asset is in service through depreciation.

B. Please see Attachment A to this response, which provides an accumulated depreciation reserve balance rollforward for the periods of August 2017 to December 2018. The rollforward shows the monthly book depreciation expense, which increases the accumulated depreciation reserve balance, along with the monthly RWIP closings, which decreases the balance.

Preparer: James Aurand
Title: Senior Rate Analyst
Department: Revenue Requirements – North
Telephone: 612-337-2076
Date: April 6, 2018

TIMP	Aug - 2017	Sep - 2017	Oct - 2017	Nov - 2017	Dec - 2017	Jan - 2018	Feb - 2018	Mar - 2018	Apr - 2018	May - 2018	Jun - 2018	Jul - 2018	Aug - 2018	Sep - 2018	Oct - 2018	Nov - 2018	Dec - 2018
Accumulated Reserve Beginning Balance	1,796,636	1,915,747	(2,703,454)	(4,096,618)	(4,529,778)	(4,636,295)	(4,609,154)	(4,525,570)	(4,417,708)	(4,299,168)	(4,175,772)	(4,055,584)	(3,939,973)	(3,832,383)	(3,722,671)	(3,607,184)	(3,482,830)
Book Depreciation	123,037	124,815	127,785	130,463	133,844	136,184	136,693	137,028	137,352	137,726	138,239	138,966	140,010	143,459	146,891	148,017	148,934
Closings - Removal	(3,926)	(4,744,015)	(1,520,950)	(563,622)	(240,361)	(109,043)	(53,109)	(29,166)	(18,811)	(14,330)	(18,051)	(23,355)	(32,420)	(33,746)	(31,405)	(23,663)	(124,577)
Accumulated Reserve Ending Balance	1,915,747	(2,703,454)	(4,096,618)	(4,529,778)	(4,636,295)	(4,609,154)	(4,525,570)	(4,417,708)	(4,299,168)	(4,175,772)	(4,055,584)	(3,939,973)	(3,832,383)	(3,722,671)	(3,607,184)	(3,482,830)	(3,458,473)

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Xcel Energy
Docket No.: G002/M-17-787
Response To: MN Department of Commerce Information Request No. 8
Requestors: Dorothy Morrissey, Danielle Winner
Date Received: January 24, 2018

Question:

Topic: DIMP; Plant Replacements
Reference(s): Initial filing, p. 29

A. Please identify and quantify the distribution-plant 2010 test-year costs that were included in base rates (GR-09-1153) and have since been replaced under GUIC. Identify where in the GUIC filing these 2010 test-year base rate costs have been reflected as an adjustment to the GUIC revenue requirement request.

B. Please identify the 2010 test-year costs tied to the distribution plant included in base rates that are earmarked to be replaced in 2018 and included in GUIC. Identify wherein the GUIC filing these 2010 test-year base rate costs have been reflected as an adjustment to the GUIC revenue requirement request.

Response:

A. We are unable to identify and quantify the specific distribution plant assets replaced as a part of the GUIC project. This is due to the fact the assets that are retired from our accounting records are determined using an automated statistical process within our asset accounting system.

The Company accounts for its gas distribution assets using the group accounting method. This primarily means that all assets are grouped together and depreciated as a whole, rather than as individual assets. When a retirement occurs, an automated statistical model analysis is performed by our asset accounting system. The statistical analysis is based on retirement and survivor curves derived from actuarial modeling of the historical addition and retirement data of our assets. The proper curves, based on the industry-accepted Iowa Curves, for each type of asset are assessed and approved by the Commission every five years as a part of our depreciation filings for transmission, distribution, and general assets.

A retirement curve plots the percentage of a similarly-aged group of assets that would normally be expected to be retired in any given year. For example, a retirement curve may estimate that 20 percent of assets would be expected to be retired after 20 years of life. Conversely, the survivor curve plots the percentage of a similarly-aged group of assets that would be expected to survive in any given year. The curve may state that we expect 99 percent of a group of assets to survive 1 year, 50 percent to survive 25 years, and 1 percent to survive 60 years. These curves are based on the same actuarial analysis and provide two views of the same expected pattern of life and death of a group of assets. Using the curves, the most likely vintage of asset to be retired can be determined and removed from our asset records.

As an example of how the retirement process using curves works, assume the Company is replacing 1,000 feet of main as a part of a DIMP project. At completion, the specific 1,000 feet of pipe being replaced would not specifically be removed from our accounting system. Rather, the most appropriate vintage of pipe to retire is determined using the approved curves. 1,000 feet of pipe of that appropriate vintage is identified, and that segment of pipe is retired from the system. This is an automatic process built into our asset accounting system. When new assets are being added to replace old assets, a direct link is not made between the new asset and the asset that was being retired from our asset records.

Even without having an asset-specific retirement process, the net result in our asset records is the same. The proper quantity, whether feet for mains or a count for services, is removed from our property records, along with the corresponding capitalized asset value. All assets, regardless of age, are retired at a net book value of zero. The amount of accumulated depreciation retired is the same as the capitalized asset value retired.

While we cannot identify the specific assets that were replaced during our DIMP projects, we have an idea of the vintages of pipe that was replaced. Attachment A to this response provides a listing of replacement projects either completed, or expected to be completed from 2015 through 2017. The listing of projects (without replaced asset vintage detail) was previously provided as Attachments C1(b), C1(c), and C1(d) in our 2017 GUIC Rider Filing (Docket No. G002/M-16-891). The schedule shows both mains and services replaced. For the distribution mains, the vintage of pipe replaced is provided, if that information is known. The information is more difficult to gather for services. Each service replaced has its own record stating its installation vintage. With thousands of services replaced each year, knowing the vintage of services replaced would require manually reviewing thousands of records. Many services are of similar vintages as the mains they are connected to, but service relocations and damaged service replace will cause services to be replaced independent of a main replacement.

As shown in Attachment A, the mains that were replaced were relatively old. Based on the 45-year average service life approved for depreciation distribution mains in the 2010 rate case (as shown in our response to Department Information Request No. 4), a large portion of these would have either been fully depreciated, or close to fully depreciated at the time of the last rate case. Even though we cannot specifically quantify the amount of installed value of the mains replaced in the DIMP projects, we can confidently say that in the rate base of the last gas rate case, the replaced assets would have had a net book value far lower than their initial capitalized value. Services had an approved average service life of 40 years at the same time period.

B. The 2018 information included in our current GUIC filing is all forecast-based information. When preparing capital forecasts for distribution assets, the Company does not plan the retirement of specific assets. Rather, forecasted retirement percentages are applied to beginning plant balances, and that amount is retired monthly throughout the entire forecast period. The forecast retirement percentages are based on a five-year average of historical retirements. The amount of retirements is calculated and removed from the forecasted plant balance, but those retirements are not assigned to specific assets. As such, the Company cannot identify specific distribution assets slated to be retired as a part of the planned 2018 GUIC projects.

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Date:	February 14, 2018

NSP-MN Main & Services DIMP Replacements					Main Footage			Service		
Division	Project	WO	Year Retired Main was Installed	Remaining Depreciable Service Life 1/1/2010 [1]	Estimate	Actual Replaced	Actual Installed from Passport	Estimate	Replaced	Transferred
St Paul	STP/ARLINGTON, NEVADA, NEBRASKA BTN. WHITE BEAR & FURNESS	11935351	1977	12	12,760	7,100	12,760	230	223	4
	ROSEVILLE/ COHANSEY ST. PROJECT/ INSTALL 7500' OF 2" PE	12118923	1965	0	7,500	4,530	7,517	74	71	2
	STP / CLARENCE ST BTN ARLINGTON AVE E & HOYT AVE E / DIMP PR	12096468	1967	2	2,600	1,300	1,300	48	46	4
	Barclay/Dieter	12185039	Unknown	-	3,750	2,675	3,925	60	58	4
	STP / IVY AVE E XST: RUTH ST / LOW PRESSURE DIMP PROJECT	12088590	1953	0	16,000	11,350	16,031	218	224	0
	STP / 7TH ST W BTN ALTON & RANKIN ST	12217850	1972	7	2,326	4,660	2,326	24	21	4
	Idaho / Barclay / Clarence	12227467	1960	0	7,350	4,775	7,467	99	93	8
	ROSEVILLE/ GALTIER ST/ INSTALL 4600' OF 2" PE MAIN (DIMP)	12122749	Unknown	-	4,400	2,405	4,560	49	48	0
White Bear Lake	VADNAIS HEIGHTS-5-STAR MOBILE ESTATES-INSTALL 10,480' 2" PE	12100647	1974	9	10,480	9,225	10,124	190	112	77
	LAKE ELMO-CIMARRON MOBILE HOME PARK-SOUTH HALF-RENEW MAIN	12148971	1970	5	15,000	15,234	15,234	250	228	0
	LAKE ELMO-CIMARRON MOBILE HOME PARK-NORTH HALF-RENEW MAIN*	12225339	1970	5	16,709	16,064	16,709	252	237	0
	WBL/OPH/Area D	12200298	1962	0	5,000	4,520	5,097	12	14	7
	Vad Heights - North Star Estates	12226824	1972	7	10,000	7,040	9,485	172	161	8
	BAYPORT 5TH ST S INSTALL 3900' OF 2"PE MAIN RENEW 43 SVCS	12093773	Unknown	-	2,900	2,000	3,845	43	16	23
	NO ST PAUL / 14th AVE E	11945105	1978	13	3,865	2,105	3,999	48	40	6
Wyoming	Forest Lake - Carry-over from 2014	12185020	1968	3	9,000	10,850	8,741	93	68	28
	Forest Lake - 11th Ave & 6th St	12233388	1968	3	4,100	3,310	3,310	36	41	6
	Forest Lake - 1st Ave / 2nd Ave / 8th St / 7th St / 6th St	12234310	Unknown	-	4,650	3,750	4,642	27	43	9
Newport	Cloman Way & Lower 67th St	12262781	1971	6	5,500	3,900	6,322	152	154	0
	ST PAUL PARK /2015 DIMP/ DIXON / BLOSSOM	12148969	Unknown	-	2,204	950	2,224	26	26	0
	2015 DIMP / ST PAUL PK / DIXON DR	12149144	Unknown	-	2,581	1,600	2,549	29	29	0
	2015 DIMP / ST PAUL PK / GARY/ SELBY / DAYTON	12149707	Unknown	-	9,274	5,050	9,274	110	110	0
	ST PAUL PARK / 2015 DIMP / PORTLAND AVE / 13TH / 15TH	12101212	1972	7	1,800	1,240	1,764	16	11	5
	SOUTH ST PAUL / 2015 DIMP / BUTLER / KASSAN	12089427	1974	9	2,224	2,980	2,224	20	15	3
	SOUTH ST PAUL / 2015 DIMP BUTLER AVE / BUTLER CT	12101218	1974	9	2,298	1,200	2,298	30	26	6
	Denton	12255539	1973	8	4,828	4,220	4,828	75	75	0
	Burns Ave	12170859	Unknown	-	6,901	3,900	6,902	85	73	11
St Cloud	DLH / DIMP / RIVER'S EDGE PARKING	12188957	Unknown	-	250	256	270	2	0	0
	St Cloud - Lincoln Ave*	12223516	Unknown	-	7,750	5,990	6,273	36	18	11
	Watertown	12162124	Unknown	-	10,200	7,030	10,210	95	73	37
	Sauk Rapids - 7th St NE (@ 2nd Ave NE)	12227154	Unknown	-	286	250	250	3	3	0
Southeast	GOODVIEW-LAKE VILLAGE MOBILE HOME PARK	12157111	1974	9	9,989	6,930	8,455	230	192	0
	Northfield Viking Ter	12241776	1970	5	10,550	8,525	7,677	180	180	0
	7th St S - Lake City	12205025	1971	6	1,400	-	1,256	6	0	0
	Hallstrom Dr & Burton St - Red Wing	12218584	1971	6	17,000	14,482	14,482	270	136	25
	Bluffview - Winona	12231997	1971	6	2,000	1,120	1,626	5	12	3
	Bush St & Langsford Ave - Red Wing	12212950	1972	7	5,950	5,100	6,337	85	69	7
	Hillsdale - Hidden Valley Mobile Home Park	12162836	1976	11	10,064	8,115	10,699	185	176	0
Moorhead	Moorehead 30th Ave & 8th St S	12215066 & 12208317	Unknown	-	975	-		1	0	0
	Moorehead Dale & 5th St S	12215099 & 12210767	Unknown	-	1,608	-	1,599	32	0	0
	Service Materials									
		Totals			254,022	195,731	244,591	3,598	3,122	298

[1] Remaining Service Life at start of 2010 Test Year in 2010 Gas Rate Case (G002/GR-09-1153). Based on Gas Distribution Main Depreciation Average Service Life of 45 Years (Approved in E,G002/D-07-1528)

NSP-MN Main & Services DIMP Replacement Projects 2016

Area	Work Order Number	Description	Year Retired Main was Installed	Remaining Depreciable Service Life 1/1/2010 [1]	Total Design FT.	Tot. Svc
St Paul	12092489	ST PAUL - ARMSTRONG AVE XST: CHATSWORTH ST S	1990	25	1,350	28
	12328949	ST PAUL - ARMSTRONG AVE	1990	25	7,506	150
	12381180	ST PAUL - ATLANTIC, DULUTH & LARPENTEUR	1955	0	8,900	118
	12294860	ROSEVILLE - GLENHILL, WOODLYNN, CLARMAR	1955	0	7,810	81
	12398688	LAUDERDALE - EUSTIS ST	Unknown	-	1,100	17
	12380740	ROSEVILLE - WEWERS RD	Unknown	-	1,400	15
	12404989	ST PAUL - DOWNTOWN - 10TH-MINNESOTA	1957	0	1,200	5
	12344852	ROSEVILLE - COUNTY RD C, FISK, AVON, GROTTO	1958	0	23,400	305
	12444470	ST PAUL - DOWN TOWN (Kellogg)	1956	0	150	-
	12361662	ST PAUL - JUNO CONTRACTOR PORTION	1980	15	4,750	56
	12358730	ST PAUL - JUNO LOCAL PORTION	1980	15	1,260	20
	12364882	ST PAUL - AURORA - LOCAL PORTION	1980	15	960	36
	12369728	ST PAUL - AURORA - CONTRACTOR PORTION	1980	15	3,875	100
	12317526	ST PAUL - BERKELY-STANFORD-WELLESLY	1980	15	10,440	195
	12294862	ROSEVILLE - SKILLMAN-ELDRIDGE	1963	0	6,700	79
White Bear Lake	12344860	LAKE ELMO - 32ND ST	Unknown	-	8,600	77
	12293638	LAKE ELMO - LAKE ELMO AVE	Unknown	-	6,800	51
	12334697	NORTH ST PAUL - 19TH AVE	1956	0	7,000	85
	12371725	BAYTOWN TWP/ 13606 30TH ST N	Unknown	-	320	5
	12320156	OAKDALE - GROSPOINT AVE	1960	0	16,200	178
	12317855	WHITE BEAR LAKE - FLORENCE ST	1976	11	16,600	109
	12320058	MAPLEWOOD - ROSELAWN AVE	1954	0	12,900	179
	12320143	OAKDALE - GERSHWIN AVE	1967	2	9,500	70
	12320392	SHOREVIEW - DEBRA LN	1976	11	11,200	105
	12317856	SHOREVIEW - NANCY PL	1971	6	7,600	85
	12275730	OAKDALE - GREENE AVE	Unknown	-	2,150	22
Wyoming	12334677	FOREST LAKE - 2ND ST SE	1972	7	10,900	128
Newport	12346387	SOUTH ST PAUL - 3RD AVE S - 6TH ST S	Unknown	-	1,680	28
	12352620	MENDOTA HTS - 3RD ST-VANDALL-SOMERSET	1968	3	1,900	22
	12352631	ST PAUL PARK - 13TH-14TH-CHICAGO	Unknown	-	8,815	100
	12346491	SOUTH ST PAUL - 2ND AVE S - MARIE AVE	Unknown	-	7,530	120
	12346357	MENDOTA HTS - HWY 13 - WACHTER AVE	Unknown	-	911	5
St Cloud	12342575	ST JOSEPH - 1ST AVE NE - CTY RD 75	1966	1	9,150	79
	12403875	SARTELL - MISSISSIPPI RIVER CROSSING	1973	8	1,700	-
	12249351	DELANO	Unknown	-	14,800	127
Southeast	12385504	WINONA - 3RD ST BTW GALE ST-MECHANIC ST	1974	9	8,100	127
	12354151	NORTHFIELD - FLORELLAS CT	1968	3	1,550	22
	12328936	FARIBAULT - 8TH ST SW	Unknown	-	5,320	48
	12345274	FARIBAULT - 7TH ST NW	1980	15	4,900	43
	12350531	FARIBAULT - 8TH ST SW, BOTSFORD, CARLTON	Unknown	-	3,000	49
Moorhead	12359542	MOORHEAD - REGAL ESTATES	Unknown	-	10,500	210
2016 DIMP-related Main Replacement Total					**270,427**	**3,279**

[1] Remaining Service Life at start of 2010 Test Year in 2010 Gas Rate Case (G002/GR-09-1153). Based on Gas Distribution Main Depreciation Average Service Life of 45 Years (Approved in E,G002/D-07-1528)

NSP-MN Main & Services DIMP Replacement Projects 2017

Area	Work Order Number	Description	Year Retired Main was Installed	Remaining Depreciable Service Life 1/1/2010 [1]	Total Design FT.
St Paul	12294045	ROSEVILLE - FERNWOOD ST	1955	0	3,760
	12315892	ST PAUL - CASE AVE BTN EDGERTON-EARL	1979	14	11,300
	12328310	ST PAUL - HAGUE/SELBY	1978	13	6,745
	12326608	ST PAUL - EDMOND	Unknown	-	5,290
	N/A	ST PAUL - ST PETER, FORD 4TH	1963	0	4,200
	12320752	ST PAUL - ETNA-BIRMINGHAM-WINCHELL	1962	0	9,600
White Bear Lake	12317581	ARDEN HILLS - ARDEN VIEW DR	Unknown	-	2,300
	12320389	ARDEN HILLS - GLENPAUL AVE	1955	0	4,700
	12319969	MAHTOMEDI - GRIFFIN AVE	1968	3	3,200
	12092590	BAYPORT - 7TH ST	1964	0	1,000
Wyoming	12320014	FOREST LAKE - 11TH AVE SW (LAKE ST)	Unknown	-	2,100
	12320051	FOREST LAKE - 208TH-209TH ST	1969	4	4,000
	12320027	FOREST LAKE - IVERSON AVE	1967	2	3,700
	N/A	FOREST LAKE - HEATH AVE	1968	3	3,600
Newport	12352434	COTTAGE GROVE - IRONWOOD	1971	6	3,338
	12438126	ST PAUL - BURNS-RUTH	1955	0	11,715
	DE 522036	COTTAGE GROVE - HYDE	1961	0	3,710
	DE 521888	COTTAGE GROVE - PT DOUGLAS RD, IDEAL AVE	1961	0	4,735
	DE 521609	COTTAGE GROVE - IDEAL-85TH ST	1962	0	4,160
	DE 521021	MENDOTA HTS - BACHELOR-SUTTON-MARIE	1973	8	10,570
	DE 526906	INVER GROVE HTS - DAWN-UPPER 75TH-77TH	1971	6	5,160
	DE 519457	INVER GROVE HTS - CONROY CT	1972	7	5,400
St Cloud	N/A	ST CLOUD - 16TH AVE - 3RD ST N	1972	7	4,100
	12412846	ST CLOUD - 44TH AVE N, APPOLLO BY VA	1972	7	2,500
Southeast	DE 525652	WINONA - 3RD ST BTW WINONA ST-LIBERTY ST	1968	3	8,500
	12320940	NORTHFIELD - WOODLEY ST E	1977	12	500
	12344771	NORTHFIELD - ARCHIBALD ST/ASTER	1981	16	3,500
	12356426	LAKE CITY - LAKEWOOD AVE	1972	7	4,250
	12360394	RED WING - SPRUCE/SOUTHWOOD	Unknown	-	6,000
	12356414	WINONA - 9TH/52ND	1977	12	3,500
	N/A	NORTHFIELD - EDWARDS LN	1968	3	1,660
	DE 525650	RED WING - BUSH ST - PLUM ST	1983	18	3,250
	N/A	RED WING - WRIGHT/FINRUD	1975	10	10,400
Moorhead	12410474	MOORHEAD-MOBILE MANOR-1224 15TH AVE. N	1972	7	1,260
	12422040	DILWORTH - 1ST AVE SE	1972	7	5,000
2017 Designed DIMP-related Main Replacement Total					**168,703**

[1] Remaining Service Life at start of 2010 Test Year in 2010 Gas Rate Case (G002/GR-09-1153). Based on Gas Distribution Main Depreciation Average Service Life of 45 Years (Approved in E,G002/D-07-1528)

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Xcel Energy
Docket No.: G002/M-17-787
Response To: MN Department of Commerce Information Request No. 44
Requestor: Dorothy Morrissey, Danielle Winner
Date Received: March 29, 2018

Question:

Topic: Revenue Requirement Category Descriptions – DIMP Book Depreciation
Reference(s): Attachment P, p. 2, Attachment K and Attachment G

Attachment K presents the Book Depreciation rate for distribution is 2.52 percent. Please provide in a live spreadsheet with formulae intact, each of the following:

A. the calculation of the monthly depreciation amount, including the depreciation rate used, for the 2016 book depreciation amounts reported in Attachment G, page 1, for each of the months May 2016 through December 2016; Please explain any discrepancies between depreciation rate used and the Attachment K stated rates;

B. the calculation of the monthly depreciation amount reported in Attachment G, page 2, including the depreciation rate used, for each of the months in 2017; Please explain any discrepancies between depreciation rate used and the Attachment K stated rates;

C. the calculation of the monthly depreciation amount reported in Attachment G, page 3, including the depreciation rate used, for each of the months in 2018; Please explain any discrepancies between depreciation rate used and the Attachment K stated rates.

Response:

A. The total 2016 DIMP book depreciation amount of $617,899 is comprised of both distribution and software projects, which utilize different depreciation rates. Please see Attachment A to this response for the calculation of 2016 monthly depreciation amounts. Attachment A is provided in live Excel spreadsheet format to show the exact calculations with the monthly book depreciation agreeing to Attachment G, page 1 filed with our original Petition.

B. The total 2017 DIMP book depreciation amount of $1,122,399 is comprised of both distribution and software projects, which utilize different depreciation rates. Please see Attachment A to this response for the calculation of 2017 monthly depreciation amounts, which agrees to the numbers shown in Petition Attachment G, page 2.

C. The total 2018 DIMP book depreciation amount of $1,639,514 is comprised of both distribution and software projects, which utilize different depreciation rates. Please see Attachment A to this response for the calculation of 2018 monthly depreciation amounts, which agrees to the numbers shown in Petition Attachment G, page 3.

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Date: April 9, 2018

	Jan - 2016	Feb - 2016	Mar - 2016	Apr - 2016	May - 2016	Jun - 2016	Jul - 2016	Aug - 2016	Sep - 2016	Oct - 2016	Nov - 2016	Dec - 2016	Total
DIMP Depreciation													
Distribution													
Book Plant End Bal	11,591,891	11,546,320	11,589,091	11,749,440	12,241,642	12,261,514	12,492,320	13,376,189	14,023,043	19,401,948	22,695,413	22,829,753	22,829,753
Previous Book Plant End Bal	11,201,196	11,591,891	11,546,320	11,589,091	11,749,440	12,241,642	12,261,514	12,492,320	13,376,189	14,023,043	19,401,948	22,695,413	
Annual Distribution Depreciation Rate (Att. K)	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	
Monthly Distribution Depreciation Rate	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	2.52%
DIMP Distribution Book Depreciation	23,933	24,295	24,292	24,505	25,191	25,728	25,992	27,162	28,769	35,096	44,202	47,801	356,967
Software													
Book Plant End Bal					2,087,278	2,087,485	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483
Previous Book Plant End Bal						2,087,278	2,087,485	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	
Annual Software Depreciation Rate (Att. K)	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	
Monthly Software Depreciation Rate	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	20.00%
DIMP Software Book Depreciation					17,394	34,790	34,791	34,791	34,791	34,791	34,791	34,791	260,932
Total DIMP Book Depreciation (Att. G)	23,933	24,295	24,292	24,505	42,585	60,518	60,783	61,953	63,561	69,888	78,994	82,593	617,899

	Jan - 2017	Feb - 2017	Mar - 2017	Apr - 2017	May - 2017	Jun - 2017	Jul - 2017	Aug - 2017	Sep - 2017	Oct - 2017	Nov - 2017	Dec - 2017	Total
DIMP Depreciation													
Distribution													
Book Plant End Bal	24,092,041	24,084,057	23,935,755	24,112,772	25,341,828	26,558,953	27,594,739	29,004,650	32,008,551	33,940,860	35,422,537	36,312,416	36,312,416
Previous Book Plant End Bal	22,829,753	24,092,041	24,084,057	23,935,755	24,112,772	25,341,828	26,558,953	27,594,739	29,004,650	32,008,551	33,940,860	35,422,537	
Annual Distribution Depreciation Rate (Att. K)	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	
Monthly Distribution Depreciation Rate	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	2.52%
DIMP Distribution Book Depreciation	49,268	50,585	50,421	50,451	51,927	54,496	56,861	59,429	64,064	69,247	72,832	75,322	704,902
Software													
Book Plant End Bal	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483
Previous Book Plant End Bal	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	
Annual Software Depreciation Rate (Att. K)	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	
Monthly Software Depreciation Rate	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	20.00%
DIMP Software Book Depreciation	34,791	34,791	34,791	34,791	34,791	34,791	34,791	34,791	34,791	34,791	34,791	34,791	417,497
Total DIMP Book Depreciation (Att. G)	84,059	85,376	85,212	85,242	86,719	89,287	91,653	94,221	98,855	104,038	107,623	110,113	1,122,399

	Jan - 2018	Feb - 2018	Mar - 2018	Apr - 2018	May - 2018	Jun - 2018	Jul - 2018	Aug - 2018	Sep - 2018	Oct - 2018	Nov - 2018	Dec - 2018	Total
DIMP Depreciation													
Distribution													
Book Plant End Bal	36,782,087	37,292,616	37,790,888	38,747,108	41,049,288	44,302,838	47,713,176	53,137,413	58,407,873	64,009,550	68,806,998	71,434,093	71,434,093
Previous Book Plant End Bal	36,312,416	36,782,087	37,292,616	37,790,888	38,747,108	41,049,288	44,302,838	47,713,176	53,137,413	58,407,873	64,009,550	68,806,998	
Annual Distribution Depreciation Rate (Att. K)	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	
Monthly Distribution Depreciation Rate	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	2.52%
DIMP Distribution Book Depreciation	76,749	77,778	78,838	80,365	83,786	89,620	96,617	105,893	117,123	128,538	139,457	147,253	1,222,017
Software													
Book Plant End Bal	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483
Previous Book Plant End Bal	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	
Annual Software Depreciation Rate (Att. K)	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	
Monthly Software Depreciation Rate	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	20.00%
DIMP Software Book Depreciation	34,791	34,791	34,791	34,791	34,791	34,791	34,791	34,791	34,791	34,791	34,791	34,791	417,497
Total DIMP Book Depreciation (Att. G)	111,541	112,570	113,629	115,156	118,578	124,411	131,408	140,684	151,914	163,330	174,249	182,045	1,639,514

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Xcel Energy			
Docket No.:	G002/M-17-787		
Response To:	MN Department of Commerce	Information Request No.	45
Requestor:	Dorothy Morrissey, Danielle Winner		
Date Received:	March 29, 2018		

Question:

Topic: Revenue Requirement Category Descriptions – TIMP Book Depreciation
Reference(s): Attachment P, p. 2, Attachment K and Attachment F

Attachment K presents the Book Depreciation rate for transmission is 1.53 percent. Please provide in a live spreadsheet with formulae intact, each of the following:

A. the calculation of the monthly depreciation amount, including the depreciation rate used, for the 2016 book depreciation amounts reported in Attachment F, page 1, for each of the months in 2016; Please explain any discrepancies between depreciation rate used and the Attachment K stated rates;

B. the calculation of the monthly depreciation amount reported in Attachment F, page 2, including the depreciation rate used, for each of the months in 2017; Please explain any discrepancies between depreciation rate used and the Attachment K stated rates;

C. the calculation of the monthly depreciation amount reported in Attachment F, page 3, including the depreciation rate used, for each of the months in 2018; Please explain any discrepancies between depreciation rate used and the Attachment K stated rates.

Response:

A. The total 2016 TIMP book depreciation amount of $1,177,163 is comprised of both distribution and transmission projects, which utilize different depreciation rates. Please see Attachment A to this response for the calculation of 2016 monthly depreciation amounts. Attachment A is provided in live Excel spreadsheet format to show the exact calculations with the monthly book depreciation agreeing to Attachment F, page 1 filed with our original Petition.

B. The total 2017 TIMP book depreciation amount of $1,490,106 is comprised of both distribution and transmission projects, which utilize different depreciation rates. Please see Attachment A to this response for the calculation of 2017 monthly depreciation amounts, which agrees to the numbers shown in Petition Attachment F, page 2.

C. The total 2018 TIMP book depreciation amount of $1,689,498 is comprised of both distribution and transmission projects, which utilize different depreciation rates. Please see Attachment A to this response for the calculation of 2018 monthly depreciation amounts, which agrees to the numbers shown in Petition Attachment F, page 3.

Preparer: Ryan Cummings
Title: Senior Financial Analyst
Department: Revenue Analysis
Telephone: 612-330-1958
Date: April 9, 2018

Northern States Power Company

	Jan - 2016	Feb - 2016	Mar - 2016	Apr - 2016	May - 2016	Jun - 2016	Jul - 2016	Aug - 2016	Sep - 2016	Oct - 2016	Nov - 2016	Dec - 2016	Total
TIMP Depreciation													
Distribution													
Book Plant End Bal	39,738,259	39,959,403	39,954,187	40,089,383	40,091,429	47,376,740	45,781,626	51,402,464	53,435,658	51,257,659	53,893,255	54,494,240	54,494,240
Previous Book Plant End Bal	39,925,286	39,738,259	39,959,403	39,954,187	40,089,383	40,091,429	47,376,740	45,781,626	51,402,464	53,435,658	51,257,659	53,893,255	
Annual Distribution Depreciation Rate (Att. K)	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	
Monthly Distribution Depreciation Rate	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	2.52%
TIMP Distribution Book Depreciation	83,647	83,683	83,909	84,046	84,190	91,842	97,816	102,043	110,080	109,928	110,408	113,807	1,155,399
Transmission													
Book Plant End Bal	1,264,748	1,266,102	1,267,650	1,270,007	1,272,062	1,271,790	1,268,714	1,271,273	1,271,382	1,270,383	1,271,087	4,904,477	4,904,477
Previous Book Plant End Bal	1,232,467	1,264,748	1,266,102	1,267,650	1,270,007	1,272,062	1,271,790	1,268,714	1,271,273	1,271,382	1,270,383	1,271,087	
Annual Transmission Depreciation Rate (Att. K)	1.53%	1.53%	1.53%	1.53%	1.53%	1.53%	1.53%	1.53%	1.53%	1.53%	1.53%	1.53%	
Monthly Transmission Depreciation Rate	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	1.53%
TIMP Transmission Book Depreciation	1,595	1,617	1,619	1,621	1,624	1,625	1,623	1,623	1,624	1,624	1,624	3,945	21,765
Total TIMP Book Depreciation (Att. F)	85,242	85,299	85,528	85,667	85,814	93,467	99,439	103,666	111,704	111,552	112,032	117,752	1,177,163

	Jan - 2017	Feb - 2017	Mar - 2017	Apr - 2017	May - 2017	Jun - 2017	Jul - 2017	Aug - 2017	Sep - 2017	Oct - 2017	Nov - 2017	Dec - 2017	Total
TIMP Depreciation													
Distribution													
Book Plant End Bal	54,503,315	54,514,836	54,520,254	54,784,362	54,909,742	55,044,386	55,057,976	55,059,463	56,257,917	57,029,103	57,803,697	59,212,616	59,212,616
Previous Book Plant End Bal	54,494,240	54,503,315	54,514,836	54,520,254	54,784,362	54,909,742	55,044,386	55,057,976	55,059,463	56,257,917	57,029,103	57,803,697	
Annual Distribution Depreciation Rate (Att. K)	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	
Monthly Distribution Depreciation Rate	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	2.52%
TIMP Distribution Book Depreciation	114,447	114,469	114,487	114,770	115,179	115,452	115,607	115,623	116,883	118,951	120,574	122,867	1,399,311
Transmission													
Book Plant End Bal	4,902,622	4,977,396	4,979,997	4,986,591	5,238,399	5,416,341	5,705,829	5,898,250	6,516,540	7,310,610	8,167,063	9,013,997	9,013,997
Previous Book Plant End Bal	4,904,477	4,902,622	4,977,396	4,979,997	4,986,591	5,238,399	5,416,341	5,705,829	5,898,250	6,516,540	7,310,610	8,167,063	
Annual Transmission Depreciation Rate (Att. K)	1.53%	1.53%	1.53%	1.53%	1.53%	1.53%	1.53%	1.53%	1.53%	1.53%	1.53%	1.53%	
Monthly Transmission Depreciation Rate	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	1.53%
TIMP Transmission Book Depreciation	6,266	6,312	6,362	6,367	6,532	6,807	7,106	7,414	7,931	8,834	9,888	10,977	90,795
Total TIMP Book Depreciation (Att. F)	120,713	120,781	120,848	121,137	121,711	122,259	122,713	123,037	124,815	127,785	130,463	133,844	1,490,106

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	Jan - 2018	Feb - 2018	Mar - 2018	Apr - 2018	May - 2018	Jun - 2018	Jul - 2018	Aug - 2018	Sep - 2018	Oct - 2018	Nov - 2018	Dec - 2018	Total
TIMP Depreciation													
Distribution													
Book Plant End Bal	59,212,616	59,212,616	59,212,616	59,212,616	59,212,616	59,212,616	59,212,616	59,212,616	61,263,212	61,263,212	61,263,212	61,263,212	61,263,212
Previous Book Plant End Bal	59,212,616	59,212,616	59,212,616	59,212,616	59,212,616	59,212,616	59,212,616	59,212,616	59,212,616	61,263,212	61,263,212	61,263,212	
Annual Distribution Depreciation Rate (Att. K)	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	
Monthly Distribution Depreciation Rate	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	2.52%
TIMP Distribution Book Depreciation	124,346	124,346	124,346	124,346	124,346	124,346	124,346	124,346	126,500	128,653	128,653	128,653	1,507,230
Transmission													
Book Plant End Bal	9,514,813	9,810,480	10,038,505	10,318,267	10,623,994	11,121,668	11,760,810	12,756,560	13,788,464	14,758,820	15,551,689	16,193,852	16,193,852
Previous Book Plant End Bal	9,013,997	9,514,813	9,810,480	10,038,505	10,318,267	10,623,994	11,121,668	11,760,810	12,756,560	13,788,464	14,758,820	15,551,689	
Annual Transmission Depreciation Rate (Att. K)	1.53%	1.53%	1.53%	1.53%	1.53%	1.53%	1.53%	1.53%	1.53%	1.53%	1.53%	1.53%	
Monthly Transmission Depreciation Rate	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	1.53%
TIMP Transmission Book Depreciation	11,838	12,346	12,681	13,005	13,379	13,893	14,619	15,664	16,959	18,238	19,365	20,281	182,268
Total TIMP Book Depreciation (Att. F)	136,184	136,693	137,028	137,352	137,726	138,239	138,966	140,010	143,459	146,891	148,017	148,934	1,689,498

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Xcel Energy
Docket No.: G002/M-17-787
Response To: MN Department of Commerce Information Request No. 40
Requestors: Dorothy Morrissey, Danielle Winner
Date Received: March 27, 2018

Question:

Topic: TIMP/DIMP Capital Expenditures and TIMP/DIMP Plant-in-Service Balances
Reference(s): Attachments E, F and G; DOC IR Nos. 14 and 15

A. Response to Part D of DOC IR No. 14 indicates the Attachment E reported capital expenditures exclude both internal labor and removal work in progress (RWIP) costs. Please explain and reconcile the $9.231 million 2018 TIMP Plant-in-Service balance increase (2018 YE $77.453 – 2017 YE $68.222 shown in Attachment F) with the estimated $8.715 million 2018 capital expenditure (Attachment E).

B. Response to Part D of DOC IR No. 15 indicates the Attachment E reported capital expenditures exclude both internal labor and removal work in progress (RWIP) costs.

(1) Please explain and reconcile the $13.483 million 2017 DIMP Plant-in-Service balance increase (2017 YE $38.400 – 2016 YE $24.917 shown in Attachment G) with the estimated $12.969 million 2017 capital expenditure (Attachment E);

(2) Please explain and reconcile the $13.716 million 2016 DIMP Plant-in-Service balance increase (2016 YE $24.917 – 2015 YE $11.201 shown in Attachment G and response to DOC IR No. 15, Part D, Attachment A) with the actual $12.799 million 2016 capital expenditure (Attachment E).

Response:

A. & B. Capital expenditures and plant additions, while linked, are not perfectly correlated, and the amounts usually differ. Most of the capital work in TIMP and DIMP are placed into service on a closing pattern, where a specific percentage of the rolling construction work in progress (CWIP) balance for the project is closed to plant in service each month. In most cases for TIMP and DIMP projects, the specific percentage is less than 100 percent, meaning a residual CWIP balance carries over at the end of each month. Based on the timing of capital expenditures and the closing pattern being used, it is possible to have a greater or lesser increase in plant in service than the capital expenditures in a given year.

In Attachment A to this response (provided in live Excel spreadsheet format), the Company presents a CWIP rollforward for the requested variances with references to Petition Attachment E, F and G provided. The CWIP rollforward displays the CWIP beginning balance, CWIP expenditures, allowance for funds used during construction, closings-book, and CWIP ending balance. Additionally, the CWIP rollforward shows the internal labor amounts which have been excluded from the rate base amounts.

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Title:	Senior Rate Analyst
Department:	Revenue Requirements – North
Telephone:	612-337-2076
Date:	April 6, 2018

Northern States Power Company

Response to Part A:

TIMP	Jan - 2018	Feb - 2018	Mar - 2018	Apr - 2018	May - 2018	Jun - 2018	Jul - 2018	Aug - 2018	Sep - 2018	Oct - 2018	Nov - 2018	Dec - 2018	Total 2018	
CWIP BEG BAL	1,103,585	695,750	491,560	424,880	754,715	1,060,144	1,532,932	1,956,619	2,596,834	1,031,904	970,356	792,869	1,103,585	
CWIP EXPENDITURES	88,511	88,511	158,998	606,501	606,501	963,678	1,053,791	1,623,965	1,523,178	903,337	610,678	487,632	8,715,280	
AFUDC DEBT	1,644	1,092	863	1,139	1,713	2,496	3,325	4,415	3,728	2,013	1,731	1,407	25,566	
AFUDC EQUITY	2,825	1,876	1,483	1,957	2,942	4,288	5,713	7,585	6,405	3,458	2,974	2,417	43,924	
CLOSINGS-BOOK	(500,816)	(295,668)	(228,025)	(279,762)	(305,727)	(497,675)	(639,142)	(995,749)	(3,098,242)	(970,356)	(792,869)	(642,162)	(9,246,192)	
CWIP END BAL	695,750	491,560	424,880	754,715	1,060,144	1,532,932	1,956,619	2,596,834	1,031,904	970,356	792,869	642,162	642,162	
CWIP BEG BAL INTERNAL LABOR	249,539	249,539	249,539	249,539	249,539	249,539	249,539	249,539	249,539	233,797	233,797	233,797	249,539	
CWIP EXPENDITURES INTERNAL LABOR	-	-	-	-	-	-	-	-	-	-	-	-	-	
CLOSINGS-BOOK INTERNAL LABOR	-	-	-	-	-	-	-	-	(15,742)	-	-	-	(15,742)	
CWIP END BAL INTERNAL LABOR	249,539	249,539	249,539	249,539	249,539	249,539	249,539	249,539	233,797	233,797	233,797	233,797	233,797	
CWIP EXPENDITURES WITHOUT INTERNAL LABOR	88,511	88,511	158,998	606,501	606,501	963,678	1,053,791	1,623,965	1,523,178	903,337	610,678	487,632	8,715,280	*Att. E*
CLOSINGS-BOOK WITHOUT INTERNAL LABOR	(500,816)	(295,668)	(228,025)	(279,762)	(305,727)	(497,675)	(639,142)	(995,749)	(3,082,500)	(970,356)	(792,869)	(642,162)	(9,230,451)	*Att. F change in Plant In-Service*
PLANT ADDITIONS WITHOUT INTERNAL LABOR	500,816	295,668	228,025	279,762	305,727	497,675	639,142	995,749	3,082,500	970,356	792,869	642,162	9,230,451	*Att. F change in Plant In-Service*

Response to Part B (1):

DIMP	Jan - 2017	Feb - 2017	Mar - 2017	Apr - 2017	May - 2017	Jun - 2017	Jul - 2017	Aug - 2017	Sep - 2017	Oct - 2017	Nov - 2017	Dec - 2017	Total 2017	
CWIP BEG BAL	2,036,987	335,220	1,227,513	1,296,161	2,474,258	2,599,043	2,306,627	2,555,801	3,091,169	901,541	678,018	474,206	2,036,987	
CWIP EXPENDITURES	(410,137)	882,949	111,438	1,349,354	1,362,564	961,293	1,301,553	1,973,055	2,033,054	1,875,303	1,405,175	808,060	13,653,661	
AFUDC DEBT	918	1,306	2,132	2,119	2,217	2,206	2,249	2,276	1,335	355	398	382	17,893	
AFUDC EQUITY	1,751	2,539	4,395	4,115	4,383	4,361	4,325	4,437	2,624	698	783	752	35,163	
CLOSINGS-BOOK	(1,294,300)	5,501	(49,317)	(177,491)	(1,244,380)	(1,260,275)	(1,058,954)	(1,444,400)	(4,226,641)	(2,099,879)	(1,610,169)	(971,992)	(15,432,297)	
CWIP END BAL	335,220	1,227,513	1,296,161	2,474,258	2,599,043	2,306,627	2,555,801	3,091,169	901,541	678,018	474,206	311,407	311,407	
CWIP BEG BAL INTERNAL LABOR	1,454,866	1,425,616	1,428,742	1,238,091	1,242,233	1,266,082	1,260,577	1,295,088	1,301,997	241,495	223,573	207,215	1,454,866	
CWIP EXPENDITURES INTERNAL LABOR	2,762	5,609	6,969	4,615	39,173	37,645	57,678	41,398	162,238	149,649	112,133	64,483	684,353	
CLOSINGS-BOOK INTERNAL LABOR	(32,012)	(2,483)	(197,619)	(474)	(15,323)	(43,151)	(23,168)	(34,489)	(1,222,740)	(167,570)	(128,492)	(82,113)	(1,949,634)	
CWIP END BAL INTERNAL LABOR	1,425,616	1,428,742	1,238,091	1,242,233	1,266,082	1,260,577	1,295,088	1,301,997	241,495	223,573	207,215	189,585	189,585	
CWIP EXPENDITURES WITHOUT INTERNAL LABOR	(412,899)	877,339	104,469	1,344,739	1,323,391	923,648	1,243,875	1,931,657	1,870,816	1,725,654	1,293,042	743,577	12,969,308	*Att. E*
CLOSINGS-BOOK WITHOUT INTERNAL LABOR	(1,262,288)	7,984	148,302	(177,017)	(1,229,057)	(1,217,124)	(1,035,786)	(1,409,911)	(3,003,901)	(1,932,309)	(1,481,678)	(889,879)	(13,482,663)	*Att. G change in Plant In-Service*
PLANT ADDITIONS WITHOUT INTERNAL LABOR	1,262,288	(7,984)	(148,302)	177,017	1,229,057	1,217,124	1,035,786	1,409,911	3,003,901	1,932,309	1,481,678	889,879	13,482,663	*Att. G change in Plant In-Service*

Response to Part B (2):

DIMP	Jan - 2016	Feb - 2016	Mar - 2016	Apr - 2016	May - 2016	Jun - 2016	Jul - 2016	Aug - 2016	Sep - 2016	Oct - 2016	Nov - 2016	Dec - 2016	Total 2016	
CWIP BEG BAL	2,404,988	2,627,204	2,661,942	2,815,583	3,317,729	1,498,489	2,101,720	3,530,300	4,507,876	6,127,670	3,736,491	1,675,133	2,404,988	
CWIP EXPENDITURES	601,316	(23,507)	181,885	645,055	747,011	613,228	1,643,453	1,837,524	2,232,503	2,939,927	1,173,837	770,712	13,362,942	
AFUDC DEBT	3,958	3,998	4,528	5,301	4,075	3,108	4,918	7,390	10,546	14,764	17,998	(51,564)	29,020	
AFUDC EQUITY	7,637	8,676	9,999	12,140	9,154	6,975	11,013	16,530	23,599	33,035	40,272	(115,371)	63,659	
CLOSINGS-BOOK	(390,694)	45,571	(42,771)	(160,349)	(2,579,480)	(20,080)	(230,804)	(883,868)	(646,854)	(5,378,905)	(3,293,465)	(241,923)	(13,823,622)	
CWIP END BAL	2,627,204	2,661,942	2,815,583	3,317,729	1,498,489	2,101,720	3,530,300	4,507,876	6,127,670	3,736,491	1,675,133	2,036,987	2,036,987	
CWIP BEG BAL INTERNAL LABOR	998,620	998,801	1,016,813	1,080,599	1,088,817	1,104,676	1,137,771	1,213,942	1,303,772	1,338,137	1,451,948	1,549,627	998,620	
CWIP EXPENDITURES INTERNAL LABOR	181	18,012	63,786	8,218	15,858	33,095	76,172	89,830	34,365	113,811	97,679	12,822	563,828	
CLOSINGS-BOOK INTERNAL LABOR	-	-	-	-	-	-	-	-	-	-	-	(107,583)	(107,583)	
CWIP END BAL INTERNAL LABOR	998,801	1,016,813	1,080,599	1,088,817	1,104,676	1,137,771	1,213,942	1,303,772	1,338,137	1,451,948	1,549,627	1,454,866	1,454,866	
CWIP EXPENDITURES WITHOUT INTERNAL LABOR	601,135	(41,519)	118,098	636,837	731,152	580,133	1,567,281	1,747,694	2,198,138	2,826,116	1,076,158	757,890	12,799,113	*Att. E*
CLOSINGS-BOOK WITHOUT INTERNAL LABOR	(390,694)	45,571	(42,771)	(160,349)	(2,579,480)	(20,080)	(230,804)	(883,868)	(646,854)	(5,378,905)	(3,293,465)	(134,340)	(13,716,039)	*Att. G change in Plant In-Service*
PLANT ADDITIONS WITHOUT INTERNAL LABOR	390,694	(45,571)	42,771	160,349	2,579,480	20,080	230,804	883,868	646,854	5,378,905	3,293,465	134,340	13,716,039	*Att. G change in Plant In-Service*

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Xcel Energy
Docket No.: G002/M-17-787
Response To: MN Department of Commerce Information Request No. 37
Requestors: Dorothy Morrissey, Danielle Winner
Date Received: March 26, 2018

Question:

Topic: Universal Inputs used for revenue requirements
Reference(s): Attachment K

Please file revised schedules and attachments to reflect the following:

(1) new federal tax rates and applying its impact on current/deferred taxes, gross-up for revenue requirement and accumulated deferred income tax;

(2) depreciation method and rates from Docket D-17-581; and

(3) Commission Ordering requirements issued in Docket 16-891.

Response:

(1) Revised schedules reflecting the impact of new federal tax rates are provided in our March 27, 2018 Supplement to the Petition filed in this Docket. The table on page two of the Supplement provides the expected 2018 impact of the 2017 Tax Cut and Jobs Act.

(2) Please see Attachment A to this response for updated revenue requirement calculations reflecting the impact of the depreciation rates proposed in our 2017 Transmission, Distribution, and General Depreciation filing on our proposed 2018 GUIC Rider depreciation. The change in depreciation rates decreases revenue requirements in 2018 by approximately $540,000. Note these new depreciation rates are still being considered by the Commission and have not yet been authorized for depreciation calculations.

(3) The revised Petition attachments provided as Appendix A in our March 27, 2018 Supplement include the updated treatment for DIMP Software Costs

and QA/QC costs resulting from the Commission's February 8, 2018 Order in our 2017 GUIC Rider Filing (Docket 16-891). The table on page two of the Supplement provides the 2018 impact of this updated treatment.

Preparer:	Ryan Cummings
Title:	Senior Financial Analyst
Department:	Revenue Analysis
Telephone:	612-330-1958
Date:	April 5, 2018

MN GUIC Rider - 2018 Annual Tracker Summary

	2018 As Filed Supplement	2018 With Updated Book Depreciation	Difference
Operations & Maintenance Expenses			
TIMP	1,325,877	1,325,877	-
DIMP	3,533,000	3,533,000	-
Total Operations & Maintenance Expenses	4,858,877	4,858,877	-
Capital-Related Revenue Requirements			
TIMP	9,145,450	8,844,383	(301,067)
DIMP	6,254,352	6,018,511	(235,841)
Total Capital-Related Revenue Requirments	15,399,801	14,862,894	(536,908)
Deferred Gas Infrastructure Costs			
TIMP	820,227	820,227	-
DIMP	3,733,856	3,733,856	-
Total Deferred Gas Infrastructure Costs	4,554,083	4,554,083	-
ADIT Prorate	26,416	26,416	-
Revenue Requirement in Base Rates	(480,000)	(480,000)	-
Revenue Requirement Subtotal	**24,359,177**	**23,822,269**	**(536,908)**
Prior Year Carryover	-	-	
Revenue Requirement (RR)	**24,359,177**	**23,822,269**	**(536,908)**
Revenue Collections (RC)	24,359,177	23,822,269	(536,908)
Carryover Balance (RR - RC)	-	-	-

Northern States Power Company

TIMP - Capital Revenue Requirements	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Total
Rate Base													
CWIP	-	-	-	-	-	-	-	-	-	-	-	-	-
Plant In-Service	67,445,701	67,514,771	67,621,242	67,820,416	68,066,117	68,494,499	69,059,708	69,940,020	72,719,853	73,580,769	74,279,573	74,843,215	74,843,215
Less Accumulated Book Depreciation Reserve	(2,225,090)	(3,635,637)	(4,148,758)	(4,214,754)	(4,196,156)	(4,140,537)	(4,069,491)	(3,995,747)	(3,915,753)	(3,828,550)	(3,731,845)	(3,725,785)	(3,725,785)
Less Accumulated Deferred Taxes	7,063,971	7,145,986	7,228,001	7,310,016	7,392,031	7,474,045	7,556,060	7,638,075	7,720,090	7,802,105	7,884,120	7,966,135	7,966,135
End Of Month Rate Base	62,606,821	64,004,422	64,541,999	64,725,154	64,870,243	65,160,990	65,573,139	66,297,692	68,915,516	69,607,215	70,127,298	70,602,865	70,602,865
Average Rate Base (Prior Mo + Cur Month/2)	60,139,181	63,305,621	64,273,211	64,633,577	64,797,699	65,015,617	65,367,065	65,935,415	67,606,604	69,261,365	69,867,256	70,365,082	
Return on Rate Base													
Debt Return (Avg RB * Wtd Cost of Debt)	113,763	119,753	121,583	122,265	122,576	122,988	123,653	124,728	127,889	131,019	132,166	133,107	1,495,491
Equity Return (Avg RB * Wtd Cost of Equity)	263,109	276,962	281,195	282,772	283,490	284,443	285,981	288,467	295,779	303,018	305,669	307,847	3,458,734
Total Return on Rate Base	376,872	396,715	402,779	405,037	406,066	407,431	409,634	413,195	423,668	434,038	437,835	440,955	4,954,224
Income Statement Items													
AFUDC Pre-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-
Property Taxes	94,946	94,946	94,946	94,946	94,946	94,946	94,946	94,946	94,946	94,946	94,946	94,946	1,139,357
Book Depreciation	111,049	111,413	111,508	111,675	111,918	112,286	112,828	113,617	116,147	118,667	119,518	120,207	1,370,834
Deferred Taxes	82,015	82,015	82,015	82,015	82,015	82,015	82,015	82,015	82,015	82,015	82,015	82,015	984,179
Gross Up for Income Tax (see below)	29,261	35,025	35,954	29,436	30,140	26,638	25,373	22,529	24,954	40,268	46,878	49,333	395,789
Total Income Statement Expense	317,271	323,399	324,424	318,072	319,019	315,885	315,163	313,107	318,063	335,896	343,358	346,502	3,890,159
Total Revenue Requirement	**694,143**	**720,115**	**727,202**	**723,110**	**725,085**	**723,316**	**724,796**	**726,303**	**741,731**	**769,934**	**781,192**	**787,456**	**8,844,383**
Capital Structure													
Weighted Cost of Debt	2.27%												
Weighted Cost of Equity	5.25%												
Required Rate of Return	7.52%												
Current Income Tax Calculation													
Equity Return	263,109	276,962	281,195	282,772	283,490	284,443	285,981	288,467	295,779	303,018	305,669	307,847	3,458,734
Book Depreciation	111,049	111,413	111,508	111,675	111,918	112,286	112,828	113,617	116,147	118,667	119,518	120,207	1,370,834
Deferred Taxes	82,015	82,015	82,015	82,015	82,015	82,015	82,015	82,015	82,015	82,015	82,015	82,015	984,179
Less Tax Depreciation	383,763	383,763	385,899	404,531	404,936	416,440	423,246	435,584	438,965	408,620	395,521	391,971	4,873,238
Plus CPI-Tax Interest (If Applicable)	134	209	318	1,047	2,236	3,737	5,327	7,338	6,892	4,755	4,540	4,210	40,742
Total	72,544	86,836	89,138	72,978	74,723	66,041	62,905	55,853	61,868	99,834	116,222	122,308	981,251
Tax Rate (T/(1-T)	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351
Gross Up for Income Tax	29,261	35,025	35,954	29,436	30,140	26,638	25,373	22,529	24,954	40,268	46,878	49,333	395,789

Northern States Power Company

DIMP - Capital Revenue Requirements	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Total
Rate Base													
CWIP	-	-	-	-	-	-	-	-	-	-	-	-	-
Plant In-Service	37,253,149	37,917,701	38,406,452	39,164,233	40,874,026	43,217,516	45,620,116	49,255,621	52,710,885	56,362,264	59,507,734	61,121,272	61,121,272
Less Accumulated Book Depreciation Reserve	(5,909,857)	(5,907,980)	(5,928,762)	(5,905,682)	(5,930,433)	(5,981,675)	(6,025,210)	(6,098,015)	(6,150,872)	(6,202,893)	(6,234,909)	(6,184,776)	(6,184,776)
Less Accumulated Deferred Taxes	5,530,086	5,617,495	5,704,904	5,792,313	5,879,722	5,967,131	6,054,540	6,141,949	6,229,358	6,316,767	6,404,176	6,491,585	6,491,585
End Of Month Rate Base	37,632,920	38,208,186	38,630,310	39,277,602	40,924,737	43,232,060	45,590,785	49,211,687	52,632,399	56,248,390	59,338,468	60,814,463	60,814,463
Average Rate Base (Prior Mo + Cur Month/2)	36,752,869	37,920,553	38,419,248	38,953,956	40,101,170	42,078,399	44,411,423	47,401,236	50,922,043	54,440,394	57,793,429	60,076,465	
Return on Rate Base													
Debt Return (Avg RB * Wtd Cost of Debt)	69,524	71,733	72,676	73,688	75,858	79,598	84,012	89,667	96,328	102,983	109,326	113,645	1,039,038
Equity Return (Avg RB * Wtd Cost of Equity)	160,794	165,902	168,084	170,424	175,443	184,093	194,300	207,380	222,784	238,177	252,846	262,835	2,403,061
Total Return on Rate Base	230,318	237,635	240,761	244,111	251,301	263,691	278,312	297,048	319,111	341,160	362,172	376,479	3,442,099
Income Statement Items													
AFUDC Pre-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-
Property Taxes	50,433	50,433	50,433	50,433	50,433	50,433	50,433	50,433	50,433	50,433	50,433	50,433	605,194
Book Depreciation	66,990	68,911	69,870	70,906	72,957	76,326	80,271	85,290	91,184	97,091	102,740	106,696	989,230
Deferred Taxes	87,409	87,409	87,409	87,409	87,409	87,409	87,409	87,409	87,409	87,409	87,409	87,409	1,048,908
Gross Up for Income Tax (see below)	7,275	7,474	8,923	(1,127)	(29,054)	(36,830)	(23,926)	(54,304)	(17,825)	(13,676)	16,538	69,611	(66,920)
Total Income Statement Expense	212,106	214,227	216,635	207,621	181,745	177,337	194,187	168,828	211,200	221,257	257,120	314,149	2,576,411
Total Revenue Requirement	**442,424**	**451,862**	**457,395**	**451,732**	**433,045**	**441,029**	**472,499**	**465,875**	**530,312**	**562,416**	**619,293**	**690,628**	**6,018,511**
Capital Structure													
Weighted Cost of Debt	2.27%												
Weighted Cost of Equity	5.25%												
Required Rate of Return	7.52%												
Current Income Tax Calculation													
Equity Return	160,794	165,902	168,084	170,424	175,443	184,093	194,300	207,380	222,784	238,177	252,846	262,835	2,403,061
Book Depreciation	66,990	68,911	69,870	70,906	72,957	76,326	80,271	85,290	91,184	97,091	102,740	106,696	989,230
Deferred Taxes	87,409	87,409	87,409	87,409	87,409	87,409	87,409	87,409	87,409	87,409	87,409	87,409	1,048,908
Less Tax Depreciation	298,255	304,545	304,465	333,716	412,773	447,994	433,769	533,514	471,161	488,032	438,140	321,696	4,788,061
Plus CPI-Tax Interest (If Applicable)	1,098	853	1,226	2,184	4,934	8,856	12,472	18,803	25,591	31,450	36,146	37,339	180,953
Total	18,036	18,530	22,123	(2,794)	(72,031)	(91,311)	(59,317)	(134,632)	(44,193)	(33,906)	41,002	172,582	(165,910)
Tax Rate (T/(1-T)	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351
Gross Up for Income Tax	7,275	7,474	8,923	(1,127)	(29,054)	(36,830)	(23,926)	(54,304)	(17,825)	(13,676)	16,538	69,611	(66,920)

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Xcel Energy
Docket No.: G002/M-17-787
Response To: MN Department of Commerce Information Request No. 43
Requestor: Dorothy Morrissey, Danielle Winner
Date Received: March 29, 2018

Question:

Topic: Revenue Requirement Category Descriptions – Property Taxes
Reference(s): Attachment P, p. 2 and Attachment K

In Attachment P, the petition states "the estimated annual 2018 property tax amount for GUIC projects, the $1,159,565 for TIMP (Attachment F) and $652,677 for DIMP (Attachment G) reflect property tax rates from the pay-2017 tax year using plan in service as of December 31,2015 for property taxation." In Attachment K, the universal input for property taxes is 1.7 percent.

A. Please provide the calculation for the 2018 TIMP and DIMP property tax amounts.

B. Please provide support for the property tax rate of 1.7 percent.

C. Please provide the calculation for the 2016 TIMP property taxes (Attachment F, page 1).

D. Please provide the calculation for the 2016 DIMP property taxes (Attachment G, p. 1).

E. Please provide support that depreciation on the plant-in-service is not considered by the Minnesota Department of Revenue when determining Minnesota utility property tax assessment.

Response:

A. Please see Attachment A to this response for the calculation. The property tax amount is calculated as the Plant Balance multiplied by the Property Tax Rate.

B. Total tax paid for gas personal property was $17,153,282, and when divided by total original cost of personal property of $1,009,203,759, a 1.7percent tax rate is derived.

C. See Attachment A to this response for the calculation. The property tax amount is calculated as the Plant Balance multiplied by the Property Tax Rate.

D. See Attachment A to this response for the calculation. The property tax amount is calculated as the Plant Balance multiplied by the Property Tax Rate.

E. Depreciation is used by the MNDOR in calculating our assessed value, but it is not considered when apportioning that value to the local taxing jurisdictions. In Minnesota administrative rule 8100.0600 Apportionment, Subpart 4 Market value of the operating utility property states:

"The total market value of each company's operating utility property in Minnesota shall be:

The current original cost in each taxing district as of the last assessment date plus original cost of new construction reduced by the original cost of property retired since the last assessment date. The Minnesota portion of the unit value as adjusted under this rule shall be divided by the total current original cost to determine a percentage. The resulting percentage shall be multiplied by the current original cost in each taxing district to determine the market value in each district."

Preparers:	Ryan Cummings / Paul Koepke
Title:	Senior Financial Analyst / Consultant, Tax Reporting
Department:	Revenue Analysis / Tax Services
Telephone:	612-330-1958 / 612-330-6835
Date:	April 9, 2018

	Jan - 2016	Feb - 2016	Mar - 2016	Apr - 2016	May - 2016	Jun - 2016	Jul - 2016	Aug - 2016	Sep - 2016	Oct - 2016	Nov - 2016	Dec - 2016	Total
DIMP													
Plant Balance	11,201,196	11,201,196	11,201,196	11,201,196	11,201,196	11,201,196	11,201,196	11,201,196	11,201,196	11,201,196	11,201,196	11,201,196	11,201,196
Property Tax Calculated	15,865	15,865	15,865	15,865	15,865	15,865	15,865	15,865	15,865	15,865	15,865	15,865	190,385
Property Tax Rate	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	1.70%
TIMP													
Plant Balance	41,156,947	41,156,947	41,156,947	41,156,947	41,156,947	41,156,947	41,156,947	41,156,947	41,156,947	41,156,947	41,156,947	41,156,947	41,156,947
Property Tax Calculated	58,295	58,295	58,295	58,295	58,295	58,295	58,295	58,295	58,295	58,295	58,295	58,295	699,538
Property Tax Rate	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	1.70%

	Jan - 2017	Feb - 2017	Mar - 2017	Apr - 2017	May - 2017	Jun - 2017	Jul - 2017	Aug - 2017	Sep - 2017	Oct - 2017	Nov - 2017	Dec - 2017	Total
DIMP													
Plant Balance	24,917,235	24,917,235	24,917,235	24,917,235	24,917,235	24,917,235	24,917,235	24,917,235	24,917,235	24,917,235	24,917,235	24,917,235	24,917,235
Property Tax Calculated	35,293	35,293	35,293	35,293	35,293	35,293	35,293	35,293	35,293	35,293	35,293	35,293	423,514
Property Tax Rate	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	1.70%
TIMP													
Plant Balance	59,397,911	59,397,911	59,397,911	59,397,911	59,397,911	59,397,911	59,397,911	59,397,911	59,397,911	59,397,911	59,397,911	59,397,911	59,397,911
Property Tax Calculated	84,131	84,131	84,131	84,131	84,131	84,131	84,131	84,131	84,131	84,131	84,131	84,131	1,009,577
Property Tax Rate	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	1.70%

	Jan - 2018	Feb - 2018	Mar - 2018	Apr - 2018	May - 2018	Jun - 2018	Jul - 2018	Aug - 2018	Sep - 2018	Oct - 2018	Nov - 2018	Dec - 2018	Total
DIMP													
Plant Balance	38,399,899	38,399,899	38,399,899	38,399,899	38,399,899	38,399,899	38,399,899	38,399,899	38,399,899	38,399,899	38,399,899	38,399,899	38,399,899
Property Tax Calculated	54,390	54,390	54,390	54,390	54,390	54,390	54,390	54,390	54,390	54,390	54,390	54,390	652,677
Property Tax Rate	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	1.70%
TIMP													
Plant Balance	68,222,346	68,222,346	68,222,346	68,222,346	68,222,346	68,222,346	68,222,346	68,222,346	68,222,346	68,222,346	68,222,346	68,222,346	68,222,346
Property Tax Calculated	96,630	96,630	96,630	96,630	96,630	96,630	96,630	96,630	96,630	96,630	96,630	96,630	1,159,565
Property Tax Rate	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	1.70%

From: Peterson, Lisa R
To: Morrissey, Dorothy (COMM)
Subject: RE: Clarification of response to DOC IR 43 in Dkt 17-787
Date: Wednesday, April 11, 2018 3:45:54 PM
Attachments: image001.png

Hi Dorothy,

The $17,153,282 amount represents the actual property taxes paid in 2017. The $1,009,203,709 amount represents the original cost of gas utility property as of 12/31/15. The 1.7% property tax rate is the property taxes paid of $17.2 million divided by the $1.0 billion in property costs.

Please let me know if you have any questions.
Thanks,
Lisa

From: Morrissey, Dorothy (COMM) [mailto:dorothy.morrissey@state.mn.us]
Sent: Tuesday, April 10, 2018 2:51 PM
To: Peterson, Lisa R
Subject: Clarification of response to DOC IR 43 in Dkt 17-787

Hi Lisa,

Welcome back. I have a question on the response to DOC IR #43 in Dkt 17-787. I'd like the values $17,153,282 and $1,009,203,709 within the response clarified. It is not clear to me what year the tax paid amount of $17,153,282 is related to and what was measurement date for the $1,009,203,709 personal property amount.

Thank you for your assistance,

Dorothy Morrissey
Public Utilities Financial Analyst
651-539-1797
mn.gov/commerce
Minnesota Department of Commerce
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COMMERCE DEPARTMENT

BEFORE THE MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS
600 North Robert Street
St. Paul, MN 55101

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION
121 7th Place East, Suite 350
St Paul MN 55101-2147

IN THE MATTER OF THE APPLICATION OF CENTERPOINT ENERGY RESOURCES CORP., D/B/A CENTERPOINT ENERGY MINNESOTA GAS FOR AUTHORITY TO INCREASE RATES FOR NATURAL GAS SERVICE IN MINNESOTA

MPUC Docket No. G008/GR-17-285
OAH Docket No. 19-2500-34684

DIRECT TESTIMONY AND ATTACHMENTS OF MARK A. JOHNSON

ON BEHALF OF

THE MINNESOTA DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

FINANCIAL ISSUES

JANUARY 8, 2018

Q. What is the effect of your recommendation on the test year?

A. My recommendation reduces CPE's test-year workers compensation expense by $700,466 on a total Company basis or $393,314 on a regulated Company basis. DOC Ex.___at MAJ-19 (Johnson Direct).

XIII. NORMALIZATION AND PRORATED ACCUMULATED DEFERRED INCOME TAXES

Q. What is normalization?

A. CPE Witness, Mr. Charles W. Pringle, provided the following definition of normalization in his testimony:

> Normalized accounting is based on requirements set forth in Generally Accepted Accounting Principles ("GAAP"), to recognize the amount of taxes payable or refundable in the current year and to recognize deferred tax liabilities and assets for the future tax consequences of events that have been recognized in an entity's financial statements or tax returns. For regulatory purposes those deferred tax liabilities and/or assets impact the rate base upon which the utility is allowed to earn a return. FERC Order No. 144, issued in 1981, requires companies under FERC regulatory jurisdiction to determine their income tax allowance on a fully normalized basis. Normalization matches the income tax expense or benefit with items as they are recorded on the books. As a result, the customers paying for an expense item also receive the related income tax benefit – the most equitable result.
>
> Furthermore, the Internal Revenue Code ("IRC") requires the use of normalization as a prerequisite to claiming accelerated depreciation and certain tax credits. The IRC normalization rules basically require inclusion of deferred income tax expense in cost of service with the resulting ADIT [Accumulated Deferred Income Taxes] reducing rate base. If the tax benefits are not normalized in the ratemaking process, CNP loses the right to claim these benefits in its income tax filings. The loss of accelerated

> depreciation would significantly increase rate base to the detriment of our ratepayers, due to the elimination of the ADIT offset to rate base.

CPE Ex.___ at 6-7 (Pringle Direct).

Q. What are Accumulated Deferred Income Taxes (ADIT)?

A. Mr. Pringle stated that:

> ADIT represents a net deferred tax liability for the estimated future tax effects attributable to temporary differences based on the provisions of the enacted tax law. The effects of future changes in tax laws or rates are not contemplated as part of the calculation of ADIT.
>
> ….
>
> ADIT arises from the interaction of the IRC [Internal Revenue Code], the Company's accounting practices under GAAP, and the Company's operations. To be specific, ADIT assets and liabilities are created because of differences in the treatment of certain items between the IRC and the Company's accounting under GAAP. The Company's accounting books and records are kept under GAAP, which provides guiding principles and requirements as to when and how CenterPoint Energy Minnesota Gas records its financial results. By contrast, the IRC and the related regulations provide the rules and requirements CNP follows when completing its tax filings. These differences in methodology create temporary differences that result in recognition of deferred income taxes.

CPE Ex.___ at 7 (Pringle Direct).

In other words, normalization accounts for tax timing differences between GAAP accounting/ratemaking and tax accounting/income tax filings. Specifically, the Internal Revenue Code allows utilities to depreciate assets quickly (accelerated depreciation) while ratemaking requires an equal amount of the asset to be depreciated each year (uniform depreciation). As a result, for tax purposes CPE pays a lower level of income tax expense due to higher depreciation at the beginning of an asset's life. For ratemaking, income tax expense is more levelized due to straight-line or uniform depreciation. This difference between income tax expense for tax purposes and income tax expense for book/ ratemaking purposes results in the recording of deferred income taxes on the income statement (deferred income tax expense) and balance sheet (accumulated deferred income taxes).

Q. How have ADIT balances generally been treated for ratemaking purposes in Minnesota?

A. Similar to other rate base items, utilities have used a simple average of their beginning and ending test-year ADIT balances (or a 13 month average) to determine the amount to include in test-year rate base.

Q. Did CPE use a simple average of its beginning and ending test-year ADIT balances or a 13-month average to determine the amount to include in test-year rate base in this proceeding?

A. No. As explained in the Direct Testimony of Company Witness, Mr. Charles W. Pringle, there are specific normalization requirements for periods that employ a future test year. Internal Revenue Service Regulation Section 1.167(l)-1(h)(6) provides that ratemaking procedures and adjustments must be consistent with normalization accounting. When a utility chooses to use a forecast test year to determine depreciation, the IRS requires that "the amount of the reserve account for the period is the amount of the reserve at the beginning of the period and a pro rata portion of the amount of any projected increase to be credited or decrease to be charged to the account during such period." This is generally referred to as the "Proration Rule."

The pro rata amount of any increase or decrease during the future portion of the period is determined by multiplying the increase or decrease by a fraction, the numerator of which is the number of days remaining in the period at the time the increase is to accrue, and the denominator of which is the total number of days in the future portion of the period. This is generally referred to as the "Proration Methodology." CPE Ex.___ at 11-13 (Pringle Direct).

Q. Does the Proration Methodology apply to all ADIT balances included in rate base?

A. No. The Proration Methodology only applies to federal income tax ADIT balances that are related to depreciation expense. CPE Ex.___ at 12 (Pringle Direct).

Q. What effect does the Proration Methodology have on CPE's proposed test-year federal ADIT balances in this proceeding?

A. The Proration Methodology reduces CPE's proposed test-year federal ADIT credit balance, which increases rate base by $2,870,801. CPE Ex.___ (DAP-WP), Sch. 7, Workpaper 2, p. 2 of 5 (Poppie Direct Workpapers). This reduction in ADIT results in a test-year revenue requirement increase of $322,678. CPE Ex.___ at 13 (Pringle Direct).

Q. Is this the first time CPE has applied the Proration Rule in a Minnesota rate case proceeding?

A. Yes. CPE stated that since the preparation and filing of its 2015 Rate Case it became aware of several IRS private letter rulings (PLRs) that required utilities to use the Proration Methodology for future test years. Based on these PLRs, CPE stated that it was concerned that it too must apply the Proration Methodology to in order to ensure compliance with normalization rules. In order to gain clarity on this issue and ensure compliance with normalization rules, CPE stated that it filed its own PLR request with the IRS. Although at the time of filing its rate case CPE had yet to receive the IRS's response, the Company requested that the Commission approve the use of the Proration Methodology in this proceeding in order to avoid the risk of violating normalization rules. CPE Ex.___ at 13 (Pringle Direct).

Q. When did CPE file its PLR request with IRS and when will it receive its formal response?

A. CPE filed its PLR request with the IRS on July 28, 2017. Since the IRS normally takes about six months to issue its formal response, I expect the formal response in approximately late January, 2018.

Q. Has the Commission addressed the prorated ADIT issue before in a Minnesota rate case proceeding?

A. Yes. The Commission recently addressed this issue in Otter Tail Power Company's 2015 Rate Case (Docket No. E017/GR-15-1033). Similar to CPE, Otter Tail Power Company (OTP) filed its own PLR request with the IRS. In its PLR response, the IRS ruled that prorated ADIT did not need to be reflected in OTP's final rates because final rates were implemented after the future test-year period had ended. However, the IRS ruled that prorated ADIT applied to interim rates because they were implemented before the end of the future test-year period. Moreover, the IRS ruled that the effects of proration included in interim rates could not be undone or returned to ratepayers in the interim rate refund process.[31]

Q. What do conclude?

A. While I expect that the IRS will rule the same in CPE's PLR and determine that prorated ADIT does not need to be included in final rates, I recommend that the Commission accept CPE's test-year proration of ADIT until the IRS issues its formal response to CPE's PLR request. I will make my final recommendations later in this proceeding after I have reviewed the IRS's formal response.

[31] See Docket No. E017/GR-15-1033, OTP Supplemental Reply Comments at 2 (October 4, 2017).

Surrebuttal Testimony
Mr. Charles Pringle

Before the Public Utilities Commission of
The State of Minnesota

In the Matter of the Application of
CenterPoint Energy Resources Corp., d/b/a
CenterPoint Energy Minnesota Gas
For Authority to Increase Rates for Natural Gas Utility
Service in Minnesota

Docket No. G-008/GR-17-285
Exhibit______(CWP-S)

Income Taxes/ADIT Proration

February 27, 2018

reported on Table 4 and Table 5 of my Rebuttal Testimony. Between the date of filing the Rebuttal Testimony and the filing of our annual financial statements (Form 10-K), these amounts were remeasured. Please see the updates to Tables 4 and 5 in section III of my Surrebuttal Testimony.

II. ADIT Proration

Q. Mr. Johnson, in his Direct Testimony, recommended that the Commission accept the proration of ADIT until the IRS issues its response to the Company's request for a PLR. Has the IRS issued its response?

A. Yes. As I stated in my Rebuttal Testimony, the Company received the IRS PLR on January 29, 2018. [1]

Q. Why did the Company request a PLR?

A. The Company requested several specific rulings to interpret and apply the IRS regulations. Primarily, the requested rulings applied to the proper proration of ADIT to avoid a violation of IRS normalization requirements. It is important to avoid a violation of normalization requirements so the Company can continue to make use of accelerated depreciation which provides significant benefits to ratepayers.

Q. Please explain proration of ADIT.

[1] Exhibit___(CWP-S) Schedule 1- IRS PLR-12344-17, dated January 25, 2018.

A. The Treasury regulations provide a specific formula to prorate the additions or reductions to ADIT reserve over a future test period for purposes of setting utility rates.[2] The formula requires that a pro rata portion of any increase or decrease to the reserve be adjusted by a fraction. The numerator in the fraction is the number of days remaining in the period from when the adjustment to the reserve is accrued. The denominator is the total number of days in the future period. If balances to the ADIT depreciation reserve account are increasing, the proration formula has the effect of reducing ADIT and increasing rate base. If the ADIT deprecation reserve balances are decreasing the formula will have the opposite effect and will increase ADIT and decrease rate base.

Q. What determinations were made by the IRS in the PLR?

A. The PLR determined, subject to the specific facts and circumstances presented in the Company's request, that:

- The test period for interim rates is a future test period and *is* subject to the ADIT proration rules,
- Because the interim rate refund process is implemented after the end of the test period, it uses a historical test period and is *not* required to employ the proration methodology, and

[2] *See* Treas. Reg. § 1.167(l)-1(h)(6).

- Because final rates are implemented after the end of the test year, the computation uses an historical period and is therefore *not* required to employ the proration methodology.

Q. Did the PLR make other determinations?

A. Yes. The PLR further found:

- That the Consistency Rule[3] does not require the use of the same averaging procedure used for other components of rate base to be applied to prorated ADIT,
- That use of a simple average for certain components of rate base and a 13-month average for ADIT is not a violation of the Consistency Rule,
- That the proration requirement does not apply only to the difference between the ADIT balance used to set interim rates and the balance used to compute final rates, and
- The Company's failure to comply with the Normalization Rules in its prior general rate case was inadvertent and because the Company took corrective action in this rate filing, which was its earliest available opportunity, that it was not appropriate to apply the sanction of denial of accelerated depreciation.

Q. Did the Company prorate ADIT in its original filing?

[3] As described in the PLR, the "Consistency Rule" means "In order to satisfy the requirements of 168(i)(9)(B), there must be consistency in the treatment of costs for rate base, regulated depreciation expense, tax expense, and deferred tax revenue purposes."

A. Yes. This information was used as the basis for interim rates and was therefore consistent with the PLR. In addition, the Company used this information as the basis for its proposed final rates.

Q. Should the calculation of ADIT for purposes of setting final rates use proration?

A. No. To be consistent with the PLR, ADIT for final rates should not be prorated.

Q. How does the PLR apply to the calculation of the interim rate refund?

A. As noted above, the PLR stated that the interim rate refund process uses a historical test period and therefore does not employ the proration methodology. The Company intends to discuss with parties how this can be accomplished and will further address this issue in its compliance filing and interim rate refund plan.

Q. You stated that ADIT for final rates should not be prorated, but the original filing includes ADIT proration. Have you calculated the difference between prorating and not prorating ADIT?

A. Yes. Using the information in our original filing, proration of ADIT results in a 13-month average ADIT of $319.3 million. If ADIT is not prorated, the 13-month average ADIT is $322.2 million. The difference of $2.9 million is an increase in ADIT and therefore a corresponding decrease in rate base if proration is not utilized. I have attached these calculations as Exhibit___(CWP-S) Schedule 2. Mr. Poppie discussed the relationship between ADIT and rate base in his Rebuttal Testimony.

Q. Is the difference of $2.9 million the adjustment you recommend?

A. No. This amount reflects the original filed information and does not reflect adjustments recommended by the Company or any other party. The final ADIT amount should be determined after all other adjustments have been calculated and the additions to ADIT in the test year should not be prorated for purposes of determining final rates.

III. REVISED UNPROTECTED OTHER EDIT

Q. What updates or corrections do you have from your Rebuttal Testimony?

A. As I noted in my rebuttal testimony, the information related to the impact of the TCJA to the Company was preliminary and subject to change. Since filing my rebuttal testimony, the December 31, 2017 balance of unprotected other EDIT and subsequent 2018 amortization were revised slightly, resulting in a small increase in the amount of funds that will be returned to ratepayers.

Q. What is the total amount of EDIT and associated regulatory liability due to the TCJA?

A. The EDIT and associated regulatory liabilities recorded per book as of December 31, 2017 are shown in Table 4 below. Note that the balance of Unprotected (Other using 2-year) is updated. Other amounts on the table are unchanged.

AUTHENTICATED U.S. GOVERNMENT INFORMATION GPO

criteria given in § 388.4 of MARAD's regulations at 46 CFR part 388.

Privacy Act

Anyone is able to search the electronic form of all comments received into any of our dockets by the name of the individual submitting the comment (or signing the comment, if submitted on behalf of an association, business, labor union, etc.). You may review DOT's complete Privacy Act Statement in the **Federal Register** published on April 11, 2000 (Volume 65, Number 70; Pages 19477–78).

By Order of the Maritime Administrator.

Dated: April 26, 2012.

Julie P. Agarwal,

Secretary, Maritime Administration.

[FR Doc. 2012–10864 Filed 5–4–12; 8:45 am]

BILLING CODE 4910–81–P

DEPARTMENT OF TRANSPORTATION

Maritime Administration

[Docket No. MARAD–2012–0056]

Requested Administrative Waiver of the Coastwise Trade Laws: Vessel LONGWOOD BATEAU; Invitation for Public Comments

AGENCY: Maritime Administration, Department of Transportation.

ACTION: Notice.

SUMMARY: As authorized by 46 U.S.C. 12121, the Secretary of Transportation, as represented by the Maritime Administration (MARAD), is authorized to grant waivers of the U.S.-build requirement of the coastwise laws under certain circumstances. A request for such a waiver has been received by MARAD. The vessel, and a brief description of the proposed service, is listed below.

DATES: Submit comments on or before June 6, 2012.

ADDRESSES: Comments should refer to docket number MARAD–2012–0056. Written comments may be submitted by hand or by mail to the Docket Clerk, U.S. Department of Transportation, Docket Operations, M–30, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE., Washington, DC 20590. You may also send comments electronically via the Internet at *http://www.regulations.gov.* All comments will become part of this docket and will be available for inspection and copying at the above address between 10 a.m. and 5 p.m., E.T., Monday through Friday, except federal holidays. An electronic version of this document and all documents entered into this docket is available on the World Wide Web at *http://www.regulations.gov.*

FOR FURTHER INFORMATION CONTACT: Joann Spittle, U.S. Department of Transportation, Maritime Administration, 1200 New Jersey Avenue SE., Room W21–203, Washington, DC 20590. Telephone 202–366–5979, Email *Joann.Spittle@dot.gov.*

SUPPLEMENTARY INFORMATION: As described by the applicant the intended service of the vessel LONGWOOD BATEAU is: INTENDED COMMERCIAL USE OF VESSEL: ''Day outings, harbor cruises and sightseeing cruises for no more than six passengers with one licensed captain on a seasonal basis.'' GEOGRAPHIC REGION: ''Massachusetts, Rhode Island, Connecticut and New York.''

The complete application is given in DOT docket MARAD–2012–0056 at *http://www.regulations.gov.* Interested parties may comment on the effect this action may have on U.S. vessel builders or businesses in the U.S. that use U.S.-flag vessels. If MARAD determines, in accordance with 46 U.S.C. 12121 and MARAD's regulations at 46 CFR Part 388, that the issuance of the waiver will have an unduly adverse effect on a U.S.-vessel builder or a business that uses U.S.-flag vessels in that business, a waiver will not be granted. Comments should refer to the docket number of this notice and the vessel name in order for MARAD to properly consider the comments. Comments should also state the commenter's interest in the waiver application, and address the waiver criteria given in § 388.4 of MARAD's regulations at 46 CFR Part 388.

Privacy Act

Anyone is able to search the electronic form of all comments received into any of our dockets by the name of the individual submitting the comment (or signing the comment, if submitted on behalf of an association, business, labor union, etc.). You may review DOT's complete Privacy Act Statement in the **Federal Register** published on April 11, 2000 (Volume 65, Number 70; Pages 19477–78).

By Order of the Maritime Administrator.

Dated: April 26, 2012.

Julie P. Agarwal,

Secretary, Maritime Administration.

[FR Doc. 2012–10867 Filed 5–4–12; 8:45 am]

BILLING CODE 4910–81–P

DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

[Docket No. PHMSA–2012–0068]

Pipeline Safety: Verification of Records

AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA), DOT.

ACTION: Notice; Issuance of Advisory Bulletin.

SUMMARY: PHMSA is issuing an Advisory Bulletin to remind operators of gas and hazardous liquid pipeline facilities to verify their records relating to operating specifications for maximum allowable operating pressure (MAOP) required by 49 CFR 192.517 and maximum operating pressure (MOP) required by 49 CFR 195.310. This Advisory Bulletin informs gas operators of anticipated changes in annual reporting requirements to document the confirmation of MAOP, how they will be required to report total mileage and mileage with adequate records, when they must report, and what PHMSA considers an adequate record. In addition, this Advisory Bulletin informs hazardous liquid operators of adequate records for the confirmation of MOP.

FOR FURTHER INFORMATION CONTACT: John Gale by phone at 202–366–0434 or by email at *john.gale@dot.gov.* Information about PHMSA may be found at *http://phmsa.dot.gov.*

SUPPLEMENTARY INFORMATION:

Background

On January 10, 2011, PHMSA issued Advisory Bulletin 11–01. This Advisory Bulletin reminded operators that if they are relying on the review of design, construction, inspection, testing and other related data to establish MAOP and MOP, they must ensure that the records used are reliable, traceable, verifiable, and complete. If such a document and records search, review, and verification cannot be satisfactorily completed, the operator cannot rely on this method for calculating MAOP or MOP and must instead rely on another method as allowed in 49 CFR 192.619 or 49 CFR 195.406.

Section 192.619 currently contains four methods for establishing MAOP: (1) The design pressure of the weakest element in the segment; (2) pressure testing; (3) the highest actual operating pressure in the five years prior to the segment becoming subject to regulation under Part 192; and (4) the maximum safe pressure considering the history of the segment, particularly known corrosion and the actual operating

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pressure. The third method, often referred to as the ''grandfather clause,'' allows pipelines that had safely operated prior to the pipeline safety MAOP regulations to continue to operate under similar conditions without retroactively applying recordkeeping requirements or requiring pressure tests.

Many of the pipelines being newly subjected to safety regulation in the 1970's were relatively new and had demonstrated a safe operating history. PHMSA is now considering whether these pipelines should be pressure tested to verify continued safe MAOP. In its August 20, 2011, accident investigation report on the September 9, 2010, Pacific Gas and Electric Company natural gas transmission pipeline rupture and fire, the National Transportation Safety Board (NTSB) recommended that PHMSA should:

> Amend Title 49 CFR 192.619 to delete the grandfather clause and require that all gas transmission pipelines constructed before 1970 be subjected to a hydrostatic pressure test that incorporates a spike test. (P–11–14)

PHMSA will be addressing this recommendation in a future rulemaking.

On January 3, 2012, President Obama signed the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (Act), which requires PHMSA to direct each owner or operator of a gas transmission pipeline and associated facilities to provide verification that their records accurately reflect MAOP of their pipelines within Class 3 and Class 4 locations and in Class 1 and Class 2 locations in High Consequence Areas (HCAs). Beginning in 2013, PHMSA intends to require operators to submit data regarding verification of records in these class locations via the Gas Transmission and Gathering Systems Annual Report.

Operators of both gas and hazardous liquid pipelines should review their records to determine whether they are adequate to support operating parameters and conditions on their pipeline systems or if additional action is needed to confirm those parameters and assure safety. The Research and Special Programs Administration and the Materials Transportation Bureau, PHMSA's predecessor agencies, recognized the importance of verifying MAOP. Prior to 1996, there was a regulatory requirement titled: ''Initial Determination of Class Location and Confirmation or Establishment of Maximum Allowable Operating Pressure'' at 49 CFR 192.607. This regulation required operators to confirm the MAOP on their systems relative to class locations no later than January 1, 1973. The regulatory requirement was removed in 1996 because the compliance dates had long since passed. PHMSA believes documentation that was used to confirm MAOP in compliance with this requirement may be useful in the current verification effort.

Advisory Bulletin (ADB–2012–06)

To: Owners and Operators of Gas and Hazardous Liquid Pipeline Systems.

Subject: Verification of Records Establishing MAOP and MOP.

Advisory: As directed in the Act, PHMSA will require each owner or operator of a gas transmission pipeline and associated facilities to verify that their records confirm MAOP of their pipelines within Class 3 and Class 4 locations and in Class 1 and Class 2 locations in HCAs.

PHMSA intends to require gas pipeline operators to submit data regarding mileage of pipelines with verifiable records and mileage of pipelines without records in the annual reporting cycle for 2013. On April 13, 2012, (77 FR 22387) PHMSA published a **Federal Register** Notice titled: ''Information Collection Activities, Revision to Gas Transmission and Gathering Pipeline Systems Annual Report, Gas Transmission and Gathering Pipeline Systems Incident Report, and Hazardous Liquid Pipelines Systems Accident Report.'' PHMSA plans to use information from the 2013 Gas Transmission and Gathering Pipeline Systems Annual Report to develop potential rulemaking for cases in which the records of the owner or operator are insufficient to confirm the established MAOP of a pipeline segment within Class 3 and Class 4 locations and in Class 1 and Class 2 locations in HCAs. Owners and operators should consider the guidance in this advisory for all pipeline segments and take action as appropriate to assure that all MAOP and MOP are supported by records that are traceable, verifiable and complete.

Information needed to support establishment of MAOP and MOP is identified in § 192.619, § 192.620 and § 195.406. An owner or operator of a pipeline must meet the recordkeeping requirements of Part 192 and Part 195 in support of MAOP and MOP determination.

Traceable records are those which can be clearly linked to original information about a pipeline segment or facility. Traceable records might include pipe mill records, purchase requisition, or as-built documentation indicating minimum pipe yield strength, seam type, wall thickness and diameter. Careful attention should be given to records transcribed from original documents as they may contain errors. Information from a transcribed document, in many cases, should be verified with complementary or supporting documents.

Verifiable records are those in which information is confirmed by other complementary, but separate, documentation. Verifiable records might include contract specifications for a pressure test of a line segment complemented by pressure charts or field logs. Another example might include a purchase order to a pipe mill with pipe specifications verified by a metallurgical test of a coupon pulled from the same pipe segment. In general, the only acceptable use of an affidavit would be as a complementary document, prepared and signed at the time of the test or inspection by an individual who would have reason to be familiar with the test or inspection.

Complete records are those in which the record is finalized as evidenced by a signature, date or other appropriate marking. For example, a complete pressure testing record should identify a specific segment of pipe, who conducted the test, the duration of the test, the test medium, temperatures, accurate pressure readings, and elevation information as applicable. An incomplete record might reflect that the pressure test was initiated, failed and restarted without conclusive indication of a successful test. A record that cannot be specifically linked to an individual pipe segment is not a complete record for that segment. Incomplete or partial records are not an adequate basis for establishing MAOP or MOP. If records are unknown or unknowable, a more conservative approach is indicated.

PHMSA is aware that other types of records may be acceptable and that certain state programs may have additional requirements. Operators should ensure all records establish confidence in the validity of the records. If a document and records search, review, and verification cannot be satisfactorily completed to meet the need for traceable, verifiable, and complete records, the operator may need to conduct other activities such as in-situ examination, measuring yield and tensile strength, pressure testing, and nondestructive testing or otherwise verify the characteristics of the pipeline to support a MAOP or MOP determination.

PHMSA is supportive of the use of alternative technologies to verify pipe characteristics. Owners and operators seeking to use alternative or non-traditional technologies in the determination of MAOP or MOP, or to meet other regulatory requirements, should first discuss the proposed approach with the appropriate state or Federal regulatory agencies to determine its acceptability under regulatory requirements.

PHMSA will issue more direction regarding how operators will be required to bring into compliance gas and hazardous liquid pipelines without verifiable records for the entire mileage of the pipeline. Further details will also be provided on the manner in which PHMSA intends to require operators to reestablish MAOP as discussed in Section 23(a) of the Act.

Finally, PHMSA notes that on September 26, 2011, NTSB issued Recommendation P–11–14: Eliminating Grandfather Clause. Section 192.619(a)(3) allows gas transmission operators to establish MAOP of pipe installed before July 1, 1970, by use of records noting the highest actual operating pressure to which the segment was subjected during the five years preceding July 1, 1970. NTSB Recommendation P–11–14 requests that PHMSA delete § 192.619(a)(3), also known as the ''grandfather clause,'' and require gas transmission pipeline operators to reestablish MAOP using hydrostatic pressure testing. PHMSA reminds operators that this recommendation will be acted upon following the collection of data, including information from the 2013 Gas Transmission and Gathering Pipeline Systems Annual Report, which will allow PHMSA to determine the impact of the requested change on the public and industry in conformance with our statutory obligations.

Issued in Washington, DC, on May 1, 2012.

Alan K. Mayberry,

Deputy Associate Administrator for Field Operations.

[FR Doc. 2012–10866 Filed 5–4–12; 8:45 am]

BILLING CODE 4910–60–P

DEPARTMENT OF TRANSPORTATION

Research & Innovative Technology Administration

[Docket ID Number RITA 2008–0002]

Agency Information Collection; Activity Under OMB Review; Reporting Required for International Civil Aviation Organization (ICAO)

AGENCY: Research & Innovative Technology Administration (RITA), Bureau of Transportation Statistics (BTS), DOT.

ACTION: Notice.

SUMMARY: In compliance with the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*), this notice announces that the Information Collection Request (ICR) abstracted below has been forwarded to the Office of Management and Budget (OMB) for extension of currently approved collections. The ICR describes the nature of the information collection and its expected burden. The **Federal Register** Notice with a 60-day comment period soliciting comments on the following collection of information was published on February 29, 2012 (77 FR 12364). No comments were received.

DATES: Written comments should be submitted by June 6, 2012.

FOR FURTHER INFORMATION CONTACT: Jeff Gorham, Office of Airline Information, RTS–42, Room E34, RITA, BTS, 1200 New Jersey Avenue SE., Washington, DC 20590–0001, Telephone Number (202) 366–4406, Fax Number (202) 366–3383 or Email *jeff.gorham@dot.gov.*

Comments: Send comments to the Office of Information and Regulatory Affairs, Office of Management and Budget, 725–17th Street NW., Washington, DC 20503, Attention: RITA/BTS Desk Officer.

SUPPLEMENTARY INFORMATION:

OMB Approval No.: 2138–0039.

Title: Reporting Required for International Civil Aviation Organization (ICAO).

Form No.: BTS Form EF.

Type of Review: Extension of a currently approved collection.

Respondents: Large certificated air carriers.

Number of Respondents: 40.

Number of Responses: 40.

Total Annual Burden: 26 hours.

Needs and Uses: As a party to the Convention on International Civil Aviation (Treaty), the United States is obligated to provide ICAO with financial and statistical data on operations of U.S. air carriers. Over 99% of the data filed with ICAO is extracted from the air carriers' Form 41 submissions to BTS. BTS Form EF is the means by which BTS supplies the remaining 1% of the air carrier data to ICAO.

The Confidential Information Protection and Statistical Efficiency Act of 2002 (44 U.S.C. 3501), requires a statistical agency to clearly identify information it collects for non-statistical purposes. BTS hereby notifies the respondents and the public that BTS uses the information it collects under this OMB approval for non-statistical purposes including, but not limited to, publication of both Respondent's identity and its data, submission of the information to agencies outside BTS for review, analysis and possible use in regulatory and other administrative matters.

Comments are invited on: Whether the proposed collection of information is necessary for the proper performance of the functions of the Department concerning consumer protection. Comments should address whether the information will have practical utility; the accuracy of the Department's estimate of the burden of the proposed information collection; ways to enhance the quality, utility and clarity of the information to be collected; and ways to minimize the burden of the collection of information on respondents, including the use of automated collection techniques or other forms of information technology.

Issued in Washington, DC on May 1, 2012.

Pat Hu,

Director, Bureau of Transportation Statistics, Research and Innovative Technology Administration.

[FR Doc. 2012–10909 Filed 5–4–12; 8:45 am]

BILLING CODE 4910–HY–P

DEPARTMENT OF TRANSPORTATION

Research & Innovative Technology Administration

[Docket ID Number RITA 2008–0002]

Agency Information Collection; Activity Under OMB Review; Submission of Audit Reports—Part 248

AGENCY: Research & Innovative Technology Administration (RITA), Bureau of Transportation Statistics (BTS), DOT.

ACTION: Notice.

SUMMARY: In compliance with the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*), this notice announces that the Information Collection Request (ICR) abstracted below has been forwarded to the Office of Management and Budget (OMB) for extension of currently approved collections. The ICR describes the nature of the information collection and its expected burden. The **Federal Register** Notice with a 60-day comment period soliciting comments on the following collection of information was published on February 29, 2012 (77 FR 12365). No comments were received.

DATES: Written comments should be submitted by June 6, 2012.

FOR FURTHER INFORMATION CONTACT: Jeff Gorham, Office of Airline Information, RTS–42, Room E34, RITA, BTS, 1200 New Jersey Avenue SE., Washington,

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

Xcel Energy
Docket No.: G002/M-17-787
Response To: MN Department of Commerce Information Request No. 35
Requestors: Dorothy Morrissey, Danielle Winner
Date Received: March 26, 2018

Question:

Topic: DIMP Quantitative Risk Assessment – Problematic Steel Project
Reference(s): Attachment D2(a)

A. On Page 2, it states "lower risk pipe segments in the same block as higher risk segments may be done as part of the same project to minimize disruption to the local community." Please identify the cost amount of each DIMP pipeline replacement project attributed to replacement of low-risk-scored pipeline and/or services that is included in GUIC recovery request.

B. Pages 5: Please explain how the demarcation values for the three risk level ranges were decided.

C. Pages 6-7, reports that a Manufacturing/Construction Defect Risk Factor score of "2" is assigned if pipeline documentation of pressure test is not Traceable, Verifiable and Complete (TVC). Of the jurisdictional operating system subject to 49 CFR 192.619 requirement, please provide each of the following:

(1) the percentage of the pipeline system that lacks the required TVC documentation of pressure test; Please identify the feasible remedies and their relative costs that are available to the particular pipeline segments lacking needed documentation;

(2) the vintage of newest pipeline that lacks required TVC documentation of pressure test and explain why this segment lacks such documentation.

D. Page 8, regarding the risk matrix, Likelihood of Failure scenarios, specifically the baseline score of "3" assigned to the third-described conditions combination "Mechanical Coupled OR No TVC Test to criteria AND

Corrosion/Leakage/3rd Party." It appears the base line score, given the multiple condition inclusions, could range from a minimum of 3 to a maximum of 5. If this is correct, how was the assigned value of 3 decided for this combination; and how does use of the fixed value of 3 impact the relative accuracy of quantified risk assessment outcomes and project priority based decisions?

Response:

A. Attachment A to this response shows the capital cost for each DIMP pipeline replacement project attributed to replacement of low-risk-scored pipeline and/or services in order to minimize disruption to the local community.

B. For the Likelihood of Failure, the demarcation for the top three risk levels is the pressure of the system they are operating in; with higher pressures resulting in a higher Likelihood of Failure Score.

C. 1) Approximately 53 percent of the Intermediate Pressure pipeline system lacks traceable, verifiable and complete (TVC) documentation of a pressure test. Feasible remedies for segments lacking documentation include pressure testing to a pressure that supports the Maximum Allowable Operating Pressure (MAOP) or replacement of the segment. For some segments, due to the presence of vintage mechanical couplings, there are no acceptable alternatives remedies other than replacement. Pressure test costs are generally expected to range from $150,000 per mile to $2.0 million per mile depending on pipe size and project location. Intermediate Pressure replacement costs are generally expected to range from $3.0 million per mile to $8 million per mile depending on pipe size and project location.

(2) The newest pipeline that lacks the required TVC documentation of pressure test is a segment of the Highway 96 Line installed in 1982. The pressure is not verifiable due to the fact that there are no pressure test charts in the project documentation files.

D. The likelihood of failure score ranges from 0 to 5 based upon the relative risk scores that Company subject matter experts placed on five different combinations of risk factors. The Likelihood of Failure score considers the status of three risk conditions; these include (1) whether the pipeline is mechanically coupled, (2) whether TVC records exist of a satisfactory post construction pressure test, and (3) whether there is a history of corrosion, leakage, or third-party damage. The Likelihood of Failure score of 3 was given to the pipeline condition where the presence of either mechanical couplings or No TVC test in combination with a history of corrosion, leakage or third-party damage. The score of 3 was assigned as a relative score between conditions considered to be a greater Likelihood of Failure (conditions scoring 4 and 5) and conditions considered to be a lesser Likelihood of Failure (conditions scoring 1 and 2).

Preparer:	Eric Kirkpatrick
Title:	Director
Department:	Gas Engineering & Project Management
Telephone:	303-571-3223
Date:	April 5, 2018

Northern States Power Company

Docket No. G002/M-17-787
DOC Information Request No. 35
Attachment A - Page 1 of 1

Capital Costs - DIMP Pipeline Replacement Projects
Replacement of Low-Risk-Scored Pipeline and/or Services

Project Name	Total Install Footage	Footage of Low Risk	Cost of Low Risk Segments
FARIBAULT 109442 - IRVING AVE	4,200	400	$14,968
RED WING 189336 - REDING AVE	4,330	300	$11,226
WINONA 98082 -CONRAD DR	5,300	300	$11,226
WINONA 106932 - 44TH AVE	4,300	50	$1,871
WINONA 98162 - W 9TH ST	3,400	350	$13,097
WINONA 98341 - E 8TH ST	4,000	200	$7,484
NORTHFIELD - 321 ST W	3,950	50	$1,871
RED WING - CENTRAL PARK ST	1,600	30	$1,123
WINONA - SUNSET DR	15,050	225	$8,420
MAPLEWOOD- MARNIE & HIGHWOOD	13,300	375	$14,033

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Xcel Energy			
Docket No.:	G002/M-17-787		
Response To:	MN Department of Commerce	Information Request No.	24
Requestors:	Dorothy Morrissey, Danielle Winner		
Date Received:	February 7, 2018		

Question:

Topic: MAOP benefit
Reference(s): Attachment C1(e)

The projects East County Line Renewal (SSP to RR) and County Road B (NSP to Rice) both note that a benefit of each project is "MAOP established through uprate."

A. For each project, please explain the benefit "MAOP established through uprate."

B. Please explain whether these existing pipeline segments being replaced have uncertain/unknown/or unproven MAOPs.

C. Please explain whether the replacement pipeline segments expected MAOPs will support future customer or sales growth that cannot be served through, or is limited by, the existing MAOP status of these pipeline segments.

Response:

A. The benefit of both projects is to ensure that the maximum allowable operating pressure (MAOP) of the pipeline is confirmed by a traceable, verifiable and complete pressure test record that substantiates that a completed pressure test was conducted at a pressure greater than the MAOP of the pipeline by a safety factor of 1.25 or the factor established in 49CFR Part 192.619(a)(2), whichever is greater. Both pipelines have MAOPs based on pressure uprates that do not satisfy this criteria, and the benefit of both projects is that the new pipelines will.

B. Both pipelines were installed between 1957 and 1959 prior to the establishment of federal code requirements for gas pipeline safety under 49CFR Part 192 in 1970. The existing record evidence required to support MAOP are not certain, as they do not meet the traceable, verifiable and complete criteria set forth in PHMSA Advisory Bulletin ADB-11-01 in January of 2011. In addition, neither pipeline has a pressure test that achieves a safety factor of 1.25 or the factor established in 49CFR Part 192.619(a)(2), whichever is greater.

C. Each pipe segment will be designed and pressure tested to an MAOP of 740 psig as a common and prudent engineering practice that establishes a greater factor of safety between the pressure test and normal operating pressures. Elevating the level of the pressure test is easily achieved during the hydrotest of the pipeline by pumping in a small incremental amount of water during the test. The East County Line will continue to operate at a normal operating pressure of 220 psig, and the County Road B Line will continue to operate at a normal operating pressure of 175 psig due to limitations of interconnected pipe systems. Because the areas served by these pipelines are fully populated, they are expected to be able to support the long-term needs of the community at the existing operating pressures.

Preparer: Eric Kirkpatrick
Title: Director
Department: Gas Engineering & Project Management
Telephone: (303) 571-3223
Date: February 20, 2018

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Xcel Energy
Docket No.: G002/M-17-787
Response To: MN Department of Commerce Information Request No. 59
Requestor: Dorothy Morrissey, Danielle Winner
Date Received: April 9, 2018

Question:

Topic: DIMP – Intermediate Pressure Pipeline Assessments
Reference(s): DOC IR #35

Request:

Response to Part C of DOC IR No. 35: Please provide the total number of miles of the Intermediate pressure pipeline system that makes up the 53 percent lacking traceable, verifiable and complete documentation of a pressure test.

Response:

There are 40.5 miles (53 percent) of the intermediate pressure pipeline system that lack traceable, verifiable and complete documentation of a pressure test in the Metro area. The Metro area intermediate pressure pipeline system has been the Company's central focus due to pipeline age and higher population density. The Company has an additional 207 miles of intermediate pressure pipelines in outstate Minnesota that have not yet been evaluated to determine if they have pressure test information that is traceable, verifiable, and complete.

Preparer: Eric Kirkpatrick
Title: Director
Department: Gas Engineering & Project Management
Telephone: 303-571-3223
Date: April 16, 2018

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Xcel Energy
Docket No.: G002/M-17-787
Response To: MN Department of Commerce Information Request No. 17
Requestors: Dorothy Morrissey, Danielle Winner
Date Received: January 30, 2018

Question:

Topic: Transmission Pipeline Assessments
Reference(s): Attachment C, p. 7

Regarding the Island Line (South of River) ILI assessment project of 1.9 mile segment installed in 1952:

A. Please identify the service life of this pipe segment;

B. Please explain the economic analysis conducted that supports expending funds to allow for "proving" this 65-year old pipe and for preparations necessary to use ILI technology assessments, over investing in pipe replacement; and

C. Please support the justification for ILI assessment project expenditures given that the variance explanation statement on page 19 of Attachment C indicates the Island South pipeline is being scoped for replacement.

Response:

A. The Company is currently approved to use an average service life of 75 years for the purpose of depreciating gas transmission mains. However, the Company does not have a defined service life for these assets. The actual service life of a given asset can vary significantly based on factors including but not limited to, original installation practices, maintenance history, cathodic protection, and coating condition.

B. In-line inspection (ILI) "proving tools" are designed to traverse pipelines that have not been modified to be assessable by ILI tools and are utilized to identify restrictions though which a "smart pig" would not be able to pass. The Company utilized a "proving pig" in 2017 to determine the extent of modifications that would be necessary to make the remaining 1952 portion of the Island Line South assessable by ILI tools. No restrictions were identified that might prohibit a full ILI assessment. As such, the Company plans to proceed with a full ILI assessment of the pipeline in 2018. This assessment will be utilized to verify proper installation of the new pipeline construction and provide a condition assessment of the 1952 portion of the line. Based on the results of the ILI assessment, the Company will either repair or proceed with replacement of the 1952 portion of the line.

The total cost to complete ILI assessment of the pipeline is estimated at $0.6 million. Approximately 1.1 miles of the original 1952 pipe remains in service. The estimated unit cost for replacement of this pipe is $1,160 per foot for a total cost of $6.7 million.

C. In 2017 a portion of the 1.5 miles referenced on page 19 of Attachment C was replaced to reduce risks of failure that may occur with Union Pacific Railroad trestle work using pile driving equipment within 18 inches of the Company's pipelines. The Company originally scoped the project to account for the risk that the remaining 1.1 miles may not be assessable by ILI tools and may not be feasible to modify. The Company plans to proceed with a full ILI assessment of the pipeline in 2018. Based on the results of the ILI assessment the Company will either repair or proceed with replacement of the 1952 portion of the line.

Preparer: Ray Gardner
Title: Director
Department: Integrity Management Programs
Telephone: 303-571-3904
Date: February 9, 2018

From:	Kirschner, Brandon M
To:	Morrissey, Dorothy (COMM)
Cc:	Peppin, Michael A; Peterson, Lisa R; Liberkowski, Amy A
Subject:	Xcel Gas - Island Line
Date:	Thursday, April 05, 2018 2:32:02 PM

Dorothy,

With Lisa Peterson out on vacation, Michael Peppin forwarded your questions about our Island Line transmission project on to me. I have been working closely with our GUIC docket, so I am happy to provide some additional clarification.

The entire length of our Island Line is approximately 1.9 miles. This includes approximately 0.4 miles of the line that were replaced in 2016 in order to make the line accessible to in-line inspection equipment. The 7,900 feet referenced in Attachment B1(f) and the 1.5 miles referenced in Attachment B both represented the total scope of the Island Line Project remaining to be completed in 2017 and beyond. These amounts excluded the 0.4 miles already completed.

In our response to DOC-017 in the current docket, the 1.1 miles of pipeline mentioned was the part of the project that was slated to be worked on in 2018, while the 1.5 miles mentioned was the total remaining project for 2017 and 2018. An additional 0.34 miles (1800 feet) of pipeline was replaced in 2017. Rerouting of the line during this part of the project added approximately 300 feet to the total length of the line. The remaining 1.15 miles (6100 feet) of pipeline is slated to be replaced in 2018. With the additional 300 feet added in 2017, the total Island Line will be closer to 2.0 miles rather than 1.9 miles.

I hope this helps answer your questions surrounding the Island Line project. If you have any additional questions while Lisa is out, feel free to contact Mike Peppin or myself. Thanks!

Brandon Kirschner
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Xcel Energy
Docket No.: G002/M-17-787
Response To: MN Department of Commerce   Information Request No. 33
Requestors: Dorothy Morrissey, Danielle Winner
Date Received: March 20, 2018

Question:

Topic: DIMP Project – Intermediate Pressure Line Assessments
Reference(s): Attachment D, p. 9

Please break down the 2018 overall $19.82 million capital and $1.03 million O&M expenditures among the IP Line Assessment projects tabled on page 9 of Attachment D.

Response:

A breakdown of the 2018 overall $19.82 million capital and $1.03 million O&M expenditures among the IP Line Assessment projects is provided in the table below. Project detail for each DIMP – Intermediate Pressure Line Assessment Project is included in Petition Attachment D1(e).

IP Line Assessments (In Millions - $M)		As Filed, Docket 17-0787		
Program	Sub-Project	Program Total	GUIC Rider Recoverable Total	Non-GUIC Recoverable Total*
DIMP	Langdon Line	$ 12.5	$ 11.8	$ 0.7
	Colby Lake Lateral	$ 4.8	$ 3.4	$ 1.4
	H005 - Lexington to Snelling	$ 4.9	$ 4.6	$ 0.3
	IP Line Assessments - Total Capital	**$ 22.2**	**$ 19.8**	**$ 2.4**
	H08 - Lake Elmo 1A TBS	$ 0.2	$ 0.2	$ -
	T009 - Cottage Grove TBS	$ 0.2	$ 0.2	$ -
	Montreal Line North	$ 0.63	$ 0.63	$ -
	IP Line Assessments - Total O&M	**$ 1.03**	**$ 1.03**	**$ -**

**Note – Non-GUIC recoverable costs include betterment, internal labor, and Engineering and Supervision (E&S) overheads associated with internal labor.*

Preparer: Ray Gardner
Title: Director
Department: Integrity Management Programs
Telephone: 303-571-3904
Date: March 30, 2018

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Xcel Energy
Docket No.: G002/M-17-787
Response To: MN Department of Commerce Information Request No. 17
Requestors: Dorothy Morrissey, Danielle Winner
Date Received: January 30, 2018

Question:

Topic: Transmission Pipeline Assessments
Reference(s): Attachment C, p. 7

Regarding the Island Line (South of River) ILI assessment project of 1.9 mile segment installed in 1952:

A. Please identify the service life of this pipe segment;

B. Please explain the economic analysis conducted that supports expending funds to allow for "proving" this 65-year old pipe and for preparations necessary to use ILI technology assessments, over investing in pipe replacement; and

C. Please support the justification for ILI assessment project expenditures given that the variance explanation statement on page 19 of Attachment C indicates the Island South pipeline is being scoped for replacement.

Response:

A. The Company is currently approved to use an average service life of 75 years for the purpose of depreciating gas transmission mains. However, the Company does not have a defined service life for these assets. The actual service life of a given asset can vary significantly based on factors including but not limited to, original installation practices, maintenance history, cathodic protection, and coating condition.

B. In-line inspection (ILI) "proving tools" are designed to traverse pipelines that have not been modified to be assessable by ILI tools and are utilized to identify restrictions though which a "smart pig" would not be able to pass. The Company utilized a "proving pig" in 2017 to determine the extent of modifications that would be necessary to make the remaining 1952 portion of the Island Line South assessable by ILI tools. No restrictions were identified that might prohibit a full ILI assessment. As such, the Company plans to proceed with a full ILI assessment of the pipeline in 2018. This assessment will be utilized to verify proper installation of the new pipeline construction and provide a condition assessment of the 1952 portion of the line. Based on the results of the ILI assessment, the Company will either repair or proceed with replacement of the 1952 portion of the line.

The total cost to complete ILI assessment of the pipeline is estimated at $0.6 million. Approximately 1.1 miles of the original 1952 pipe remains in service. The estimated unit cost for replacement of this pipe is $1,160 per foot for a total cost of $6.7 million.

C. In 2017 a portion of the 1.5 miles referenced on page 19 of Attachment C was replaced to reduce risks of failure that may occur with Union Pacific Railroad trestle work using pile driving equipment within 18 inches of the Company's pipelines. The Company originally scoped the project to account for the risk that the remaining 1.1 miles may not be assessable by ILI tools and may not be feasible to modify. The Company plans to proceed with a full ILI assessment of the pipeline in 2018. Based on the results of the ILI assessment the Company will either repair or proceed with replacement of the 1952 portion of the line.

Preparer:	Ray Gardner
Title:	Director
Department:	Integrity Management Programs
Telephone:	303-571-3904
Date:	February 9, 2018

From: Kirschner, Brandon M
To: Morrissey, Dorothy (COMM)
Cc: Peppin, Michael A; Peterson, Lisa R; Liberkowski, Amy A
Subject: Xcel Gas - Island Line
Date: Thursday, April 05, 2018 2:32:02 PM

Dorothy,

With Lisa Peterson out on vacation, Michael Peppin forwarded your questions about our Island Line transmission project on to me. I have been working closely with our GUIC docket, so I am happy to provide some additional clarification.

The entire length of our Island Line is approximately 1.9 miles. This includes approximately 0.4 miles of the line that were replaced in 2016 in order to make the line accessible to in-line inspection equipment. The 7,900 feet referenced in Attachment B1(f) and the 1.5 miles referenced in Attachment B both represented the total scope of the Island Line Project remaining to be completed in 2017 and beyond. These amounts excluded the 0.4 miles already completed.

In our response to DOC-017 in the current docket, the 1.1 miles of pipeline mentioned was the part of the project that was slated to be worked on in 2018, while the 1.5 miles mentioned was the total remaining project for 2017 and 2018. An additional 0.34 miles (1800 feet) of pipeline was replaced in 2017. Rerouting of the line during this part of the project added approximately 300 feet to the total length of the line. The remaining 1.15 miles (6100 feet) of pipeline is slated to be replaced in 2018. With the additional 300 feet added in 2017, the total Island Line will be closer to 2.0 miles rather than 1.9 miles.

I hope this helps answer your questions surrounding the Island Line project. If you have any additional questions while Lisa is out, feel free to contact Mike Peppin or myself. Thanks!

Brandon Kirschner
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Xcel Energy
Docket No.: G002/M-17-787
Response To: MN Department of Commerce Information Request No. 33
Requestors: Dorothy Morrissey, Danielle Winner
Date Received: March 20, 2018

Question:

Topic: DIMP Project – Intermediate Pressure Line Assessments
Reference(s): Attachment D, p. 9

Please break down the 2018 overall $19.82 million capital and $1.03 million O&M expenditures among the IP Line Assessment projects tabled on page 9 of Attachment D.

Response:

A breakdown of the 2018 overall $19.82 million capital and $1.03 million O&M expenditures among the IP Line Assessment projects is provided in the table below. Project detail for each DIMP – Intermediate Pressure Line Assessment Project is included in Petition Attachment D1(e).

IP Line Assessments (In Millions - $M)		As Filed, Docket 17-0787		
Program	Sub-Project	Program Total	GUIC Rider Recoverable Total	Non-GUIC Recoverable Total*
DIMP	Langdon Line	$ 12.5	$ 11.8	$ 0.7
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	IP Line Assessments - Total Capital	**$ 22.2**	**$ 19.8**	**$ 2.4**
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	T009 - Cottage Grove TBS	$ 0.2	$ 0.2	$ -
	Montreal Line North	$ 0.63	$ 0.63	$ -
	IP Line Assessments - Total O&M	**$ 1.03**	**$ 1.03**	**$ -**

**Note – Non-GUIC recoverable costs include betterment, internal labor, and Engineering and Supervision (E&S) overheads associated with internal labor.*

Preparer:	Ray Gardner
Title:	Director
Department:	Integrity Management Programs
Telephone:	303-571-3904
Date:	March 30, 2018

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Xcel Energy
Docket No.: G002/M-17-787
Response To: MN Department of Commerce Information Request No. 31
Requestors: Dorothy Morrissey, Danielle Winner
Date Received: March 20, 2018

Question:

Topic: DIMP Project – Intermediate Pressure Line Assessments
Reference(s): Attachment D, p. 9; Langdon Line Replacement

A. Please identify the amount of the estimated project's costs attributed to enhanced features and/or capabilities that the 12" replacement pipeline will have over the existing pipeline.

B. Please explain how replacement of the 6-inch and 8-inch pipe supports additional reliability of the Metro area bulk system.

C. Regarding reliability, please discuss the Metro area bulk system failures or near failures that this designed pipe replacement project will diminish.

D. Please discuss whether modern day 8-inch pipe would be adequate for this project; if not please explain why; if so, please identify the cost differential between use of 12-inch pipe over 8-inch pipe for this portion of the gas operating system.

Response:

A. The estimated cost difference between replacing this segment of the Langdon pipeline with 12-inch instead of matching the existing diameters segment by segment is $4.4 million. However, this cost comes with integrity and safety benefits. Replacing the line with one continuous diameter will allow In-Line-Inspection (ILI) to be run on the entire Langdon pipeline. ILI will allow the Company to inspect the line more efficiently to ensure the integrity and safety of the pipeline. The favorable impact of associated system reliability is an additional benefit but not the basis for selection of pipe size.

B. Replacing the 6-inch and 8-inch pipe with a continuous 12-inch diameter pipe will allow ILI to be used on the entire line. ILI will enable the Company to identify and remediate flaws or pipe deterioration in advance of a pipeline failure, helping to ensure that the gas system is safe and reliable.

C. The Company recorded 17 pipeline leak repairs on the Metro Area Bulk system from 2012 through 2017. Six of the leaks were recorded as being on the main. The Langdon pipeline itself has a history of third-party damage and corrosion. Replacement of the line will eliminate pipe that has mechanical couplings, lacks records of a post construction pressure test, and has a history of corrosion and third-party damage, as well as allow for more efficient inspections via ILI.

D. The cost difference between using 8-inch diameter pipe and 12-inch diameter pipe is estimated to be approximately $3.6 Million. While 8-inch diameter pipe would be adequate for the capacity needs of the pipeline, the installation of 12-inch pipe ensures a continuous diameter for the entire Langdon pipeline. This will allow for ILI to be used on the entire line, which helps ensure gas system safety and reliability.

Preparer:	Eric Kirkpatrick
Title:	Director
Department:	Gas Engineering & Project Management
Telephone:	303-571-3223
Date:	March 30, 2018

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Xcel Energy
Docket No.: G002/M-17-787
Response To: MN Department of Commerce Information Request No. 32
Requestors: Dorothy Morrissey, Danielle Winner
Date Received: March 20, 2018

Question:

Topic: DIMP Project – Intermediate Pressure Line Assessments
Reference(s): Attachment D, pp. 10-11; Lexington to Snelling pipeline replacement

A. Please explain and distinguish the characteristics of distribution pipelines for which alternate safety inspection methods must be used and conducted on the limited segments that cannot be inspected by using the external corrosion direct assessment (ECDA) method, in order to satisfy regulatory requirements.

B. Please provide the total amount of base rate cost savings expected, and identify the plant equipment in rates that will be eliminated, as a result of removing numerous services served directly off the high pressure system.

C. Please indicate if the H005 pipeline replacement will continue to have some services directly connected to it, and if so, explain why.

D. Please identify the federal or state agency directive that requires services to not be connected to distribution pipeline having characteristics of the replaced H005 pipeline.

E. Please identify the portion of this project's costs included in the GUIC recovery request attributed to the extension of the nearby 60 psi system being undertaken in order to facilitate transfer of services.

Response:

A. In order to perform in-line-inspection (ILI) a pipeline must be constructed in a manner that allows for passage of the ILI tool. These construction limitations include the need for long radius elbows (a steel fitting that turns the pipeline) and typically constructed of one diameter. ILI tools are designed for passage inside of the pipe. For existing pipelines that are not constructed in a manner that will allow ILI, the only integrity inspection technique available is ECDA. ECDA is only able to detect locations where external corrosion may be impacting the pipeline.

By contrast, ILI tools allow the Company to inspect lines for multiple threats that include external corrosion, internal corrosion, manufacturing defects, material defects, construction defects and third party damage. Therefore, to reduce the risk from all threat types, ILI is the preferred inspection method. In order to reduce the risk associated with operating a large diameter, high-pressure distribution line in a highly populated area, the Company will be constructing the new pipeline in a manner that allows for ILI.

B. Removing services from the larger diameter, high-pressure pipeline and placing them on the lower-pressure plastic system will not result in rate base cost savings or elimination of plant equipment. In constructing the new pipeline, the Company will be removing the services from the large diameter, high-pressure pipeline in order to allow ILI to be performed without disrupting service to large volume commercial customers. Approximately 20 services will be relocated to a new 2-inch and 4-inch plastic main.

C. The new 8-inch and 12-inch steel high-pressure pipeline will not have services directly connected to it. This is being done in order to allow the pipeline to be inspected with ILI technology.

D. There are no federal or state directives that require services not be installed to the new 8-inch and 12-inch steel high-pressure pipeline. The Company has opted to not directly connect services to the pipeline in order to maintain the ability to inspect the line with ILI technology.

E. The portion of this project's capital costs included in the GUIC recovery request attributed to the extension of the nearby 60 psi system being undertaken in order to facilitate transfer of services is estimated to be $420,000.

Preparer:	Eric Kirkpatrick
Title:	Director
Department:	Gas Engineering & Project Management
Telephone:	303-571-3223
Date:	March 30, 2018

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Xcel Energy
Docket No.: G002/M-17-787
Response To: MN Department of Commerce Information Request No. 49
Requestor: Danielle Winner, Dorothy Morrissey
Date Received: April 2, 2018

Question:

Topic: Contracts/Work Orders/Invoices
Reference(s): Xcel Gas Initial Filing Attachments C and D

Request:

Please provide all contracts, work orders, and invoices from 2017 and 2018 for the following TIMP Projects:

A. 11649521 (Transmission Pipeline Assessments – Capital)
B. 11649797 (Transmission Pipeline Assessments – Capital)
C. 34000342 (Transmission Pipeline Assessments – Capital)
D. 11984286 (Transmission Pipeline Assessments – O&M)
E. 11503515 (ASVs and RCVs – Capital)
F. 11651650 (Programmatic Replacement and MAOP Remediation – Capital)
G. 11810375 (Programmatic Replacement and MAOP Remediation – Capital)
H. 34003261 (Programmatic Replacement and MAOP Remediation – Capital)

Please provide all contracts, work orders, and invoices from 2017 and 2018 for the following DIMP Projects:

A. 11649522 (Poor Performing Main Replacements – Capital)
B. 12173831 (Poor Performing Main Replacements – Capital)
C. 34000462 (Poor Performing Main Replacements – Capital)
D. 11649766 (Poor Performing Service Replacements – Capital)
E. 12173830 (Poor Performing Service Replacements – Capital)
F. 11980562 (Intermediate Pressure Line Assessments – Capital)
G. 11984278 (Intermediate Pressure Line Assessments – O&M)

H. 11649520 (Distribution Valve Replacement Project – Capital)
I. 12173704 (Distribution Valve Replacement Project – Capital)
J. 11984282 (Sewer and Gas Line Conflict Investigation- O&M)
K. 12173409 (Federal Code Mitigation- Capital)

Response:

The Company has attached all actual work order charges and contracts from 2017 for all of its GUIC projects as Attachment A and Attachment B to this response, respectively. Due to the volume of invoices related to these contracts and work orders, we have not included invoices as part of this response. Doing so would entail the assembly of many thousands of documents, and we estimate that this process would take at least a month to complete. In addition, the Company is not providing 2018 work order information at this time due to the limited scope of work completed to date related to its GUIC programs. The set of contracts provided for 2017 continue to govern the 2018 scope of work, unless otherwise stated.

Included in Attachment A is a detailed summary of all GUIC capital and O&M work order charges from 2017. Therein, the Company has specified charges corresponding to all work invoiced from and paid to contractors (see column D of "Capital Data" and "O&M Data" tabs) on GUIC-related projects. These charges are governed by the contracts provided in Attachment B. Individual invoiced amounts and corresponding invoice reference and purchase numbers are found on the respective "COV Invoice/SAP PO" tabs for both capital and O&M in Attachment A, which is provided in live Excel spreadsheet format.

The Company can readily provide specific invoices for invoice and purchase numbers identified by the Department using the information provided in this response. As another alternative, the Company would be happy to arrange an onsite inspection of the invoices with the Department and produce documents requested as a result of the inspection.

Attachments A and B are marked as "Not-Public" because they include confidential contract and pricing terms and vendor detail considered to be trade secret data as defined by Minn. Stat. § 13.37(1)(b). This information has independent economic value, from not being generally known to, and not being readily ascertainable by other parties, who could obtain economic value from its disclosure or use. The disclosure of this information could adversely impact contract negotiations, potentially increasing costs for these services for our customers. Thus, Xcel Energy maintains this information as a trade secret pursuant to Minn. Rule 7829.0500.

Attachment B is marked as "Not-Public" in its entirety. Pursuant to Minn. R. 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material:** Attachment B is a PDF collection of contracts between the Company and its vendors for 2017 work on TIMP and DIMP projects listed in this inquiry.
2. **Authors:** The contracts included in the Attachment B collection were drafted by Xcel Energy Services legal and sourcing personnel.
3. **Importance:** We protect these contract terms, as disclosure can adversely affect negotiations and increase costs for services.
4. **Date the Information was Prepared:** The Attachment B contract collection was prepared for this response April 2018.

Preparer: Andrew Sudbury
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Department: Gas System Strategy and Bus Ops XS
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Date: April 19, 2018

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

Xcel Energy
Docket No.: G002/M-17-787
Response To: MN Department of Commerce Information Request No. 62
Requestor: Dorothy Morrissey, Danielle Winner
Date Received: May 8, 2018

<u>Question:</u>

Topic: Contracts, Work Orders, Invoices
Reference(s): Xcel Trade Secret response to Department IR 49
Xcel March 27 Supplemental Filing Attach E
Xcel Initial Filing, Attach D, page 4.

In response to the Department's IR 49, the Company provided 14 contracts that govern specific parent projects for the years 2017 and 2018. However, all contracts provided have start dates prior to 2016, with some as far back as 2008.

A. Please describe, in as much detail as possible, the Company's process for renewing contracts, including how this process interacts with competitive bidding processes.

B. Please provide any contract renewal documentation related to the contracts provided in response to IR 49.

All contracts provided to the Department list at least one of Xcel's executing affiliates as "NSP-MN," which includes MN, ND, and SD. However, 12 of the 14 contracts provided also include either NSP-WI, PSCo, and/or SW PSC-NM. Further, 5 contracts contain a geographic scope of work that includes both MN and other states, and 8 contracts contain pricing schedules that include both MN and other states.

C. Please describe, in as much detail as possible, how the Company parses out MN-specific work in the contracts that govern multiple jurisdictions.

D. If any sub-contracts exist for purposes of designating MN-specific work, please provide those sub-contracts.

[TRADE SECRET BEGINS

TRADE SECRET ENDS]

E. Please explain why there are more vendors in the dataset than in the contracts provided to the Department.

F. Please also explain why the contracts provided to the Department contain contract, master agreement, and work order numbers that do not match those recorded in the dataset.

G. How can the "Outside Vendor Contract" data be traced back to a particular contract?

[TRADE SECRET BEGINS

TRADE SECRET ENDS]

H. Please confirm the Department's understanding of 2017 capital expenditures, or provide an alternative explanation reconciling these different totals found in the dataset and reported in the Supplemental Filing.

I. Please also clarify which categories and charges in the Capital Data dataset are considered "Materials, Transportation, Construction Overhead, and Other," and which are considered "Internal Labor."

Response:

See Appendix A for a list of attachments included with this response.

A. The Company's process for renewing contracts is governed by our "Procurement of Normal Goods and Services" policy. Please reference the Change Orders or Amendments section on Page 10 of Attachment A to this response for the portion of the policy that governs the change order process, which is used to amend or extend a contract term.

B. Please reference Attachment B1 to this response for contract renewal documentation for the contracts provided in our response to Information Request DOC-49. Change orders, the document used for contract renewals, are only completed when a change is made to a contract. As such not all the provided contracts have a corresponding change order. The Company has additionally provided Attachment B2, "Supply Chain Operating Requirements (SCOR)", which describes the change order process in more detail (See Section 10, Pages 77-79).

C. For contracts that govern work in multiple jurisdictions, the Company utilizes jurisdictional-specific work orders to track costs for each jurisdiction. When the Company is designing, estimating, and executing work each jurisdictional-specific work order is used for the planned work. The system maintains a reference within the work order that can tie the work back to the relevant contract.

D. Sub-contracts are not used to designate work as being Minnesota-specific. Rather the Company uses jurisdiction-specific work orders to track charges by state, as described in our response to Part C above.

E. The primary cause of our listing vendors without corresponding contracts in our DOC-49 dataset was the inadvertent omission of contracts from our response. These additional contracts are included as Attachment C to this response. Any relevant renewal documentation for the additional agreements is provided in Attachment B1 to this response.

[TRADE SECRET BEGINS

TRADE SECRET ENDS]

F. The Company utilizes different systems for the contract creation process in the Supply Chain area and the work management processing in the accounting/construction areas. Each of these systems utilizes different numbering conventions, but the work management systems have fields which provide references that link contracts from the Supply Chain system to the work management system.

Each new contract in Emptoris, our Supply Chain system, is assigned a unique, five-digit number. On the other hand, our legacy work management system, Passport, would also assign a unique, six-digit Passport number when work was tracked. Some contracts reference the Emptoris number while others reference the Passport number. Our new work management system, SAP, utilizes Outline Agreements (OA) to represent the contract (from Emptoris) in the work management system. SAP has its own unique numbering convention that is assigned to each OA. Despite the systems using different numbering systems, through references made in each system the Company is able to track work back to the contracts to ensure that charges are being assigned to the relevant contract.

To aid in tracking charges back to the contracts, we have developed Attachment D to this response. Attachment D, provided in live Excel spreadsheet format, is a subset of the information that was initially provided in the "Capital Data" and "O&M Data" tabs of DOC-49, Attachment A, but with the addition of contract numbers and vendor for each charge. The "Guide" tab of Attachment D provides instructions on how to map individual vendor-related charges to the contracts and explains the information provided in each tab of the Attachment. ***[TRADE SECRET BEGINS***

TRADE SECRET ENDS]

It should be noted that during the preparation of this response, it was discovered that two work orders related entirely to work completed in Colorado were incorrectly assigned accounting strings for Minnesota-related work in our new SAP work management system. The work orders relate to work performed by ***[TRADE SECRET BEGINS***

TRADE SECRET ENDS] The Company proposes to remove these charges in the final compliance version of this filing. The revenue requirement impact of these projects is approximately $213 in 2017 and $501 in 2018.

G. The "Capital Data" and "O&M" data tabs of Attachment D provide a listing of charges for outside vendor contract work. The Contract Number can be found in column A of each tab. For further information on how to track the individual charges to the relevant contracts, please refer to the "Guide" tab of Attachment D.

H. The intention of the data provided in DOC-49 was to provide the Department with individual charges including purchase order, vendor, and invoice number characteristics. With our response here, we hope to provide clarification as to the information provided and how it ties back to previously provided GUIC information.

Using DOC-49 data as the starting point for segregating into cost categories and type is not accurate, because the individual charge data at times mixes both capital and O&M expense types, and a portion of categories Materials, Transportation, Construction Overhead and Other relate to internal labor. Additional data is needed to breakdown the 2017 Capital Expenditures into cost categories and type, and Table 1 below summarizes the entirety of 2017 GUIC capital expenditures (i.e., recoverable and non-recoverable) by cost element group. The individual 2017 monthly charges totaling $25,643,640 can be found by cost element and internal order in Attachment E to this response.

Attachment E is provided in live Excel spreadsheet format. See the "2017 GUIC by Cost Element" and "2017 GUIC by Order" worksheet tabs. The Company is providing details underlying Table 1 below as Attachment E to this response. The Department can utilize this information to tie back to the figures included in Attachment E of the Company's Supplemental Filing.
[TRADE SECRET BEGINS

TRADE SECRET ENDS]

Table 1

2017 GUIC Capital Expenditures	Amount
Outside Vendor Contract	$17,366,758
Internal Labor (not eligible for recovery)	$489,849
Materials, Transportation, Construction Overhead, and Other Outside Services (not traceable to vendor master service agreements)	$7,787,033
Subtotal GUIC Expenditures	**$25,643,640**
RWIP	($3,684,742)
Sartell Betterment 28.1% Removal (not eligible for recovery)	($210,205)
Internal Labor (as of Supplemental Filing)	($1,374,082)
Supplemental Filing Total GUIC Expenditures, excluding internal labor	**$20,374,611**
Internal Labor (Reconciliation Difference)	$884,233
Reconciliation Total GUIC Expenditures	$21,258,844

The $17,366,758 for Contractor charges noted above is different than the ***[TRADE SECRET BEGINS*** ***TRADE SECRET ENDS]*** for Outside Vendor Contract charges that the Department summed from the data in DOC-49 partially due to mixed capital and O&M work orders in the respective capital and O&M datasets that could not be separated in that dataset. In addition, the cost element description, "Service Consumption" was used for additional outside vendor charges. The total of these charges, $3.7 million, has been included in the outside vendor contract total above and in the information provided in Attachment E, which includes data that captures all capital expenditures for Outside Vendor Contracts.[1] ***[TRADE SECRET BEGINS***

TRADE SECRET ENDS]

In the supplemental filing, we inadvertently removed too much internal labor from September 2017 to December 2017, due to both actual and forecasted amounts being included. As such, the GUIC capital expenditures were

[1] The $3.7 million amount initially labeled as service consumption in DOC-49, Attachment A, can be found on line 218 of the "A-2017 GUIC by Cost Element" tab of Attachment E to this response.

understated by approximately $900,000. We will not be requesting a modification to the requested revenue requirement to correct the error. In Table 1 and Attachment E to this response, the corrected capital expenditures and internal labor amounts will be incorporated in order to properly reconcile the differences in Total GUIC expenditures.

We believe that the additional information provided in this response and its attachments provides a clearer path for mapping vendor contracts/master service agreements to the corresponding charges for work completed. If after reviewing this response the Department would like further clarity on the relationships in the provided information, the Company would be happy to facilitate any desired discussions.

I. The categories included in the Capital Data tab provided in DOC-49, Attachment A cannot be easily separated into two categories of "Internal Labor" and "Materials, Transportation, Construction Overhead, and Other." The Company has provided Attachment E to this response, which is summarized in Table 1 above. The categories of Company Labor Loadings, Company OT Labor, and Company ST Labor are all considered internal labor. The remaining categories make up the "Materials, Transportation, Construction Overhead, and Other" bucket.

However, these amounts differ from the $489,849 of non-recoverable internal labor stated in Table 1, since a portion of the "Materials, Transportation, Construction Overhead, and Other" relate to internal labor. The Company identifies these amounts through a specialized query from our capital asset accounting database. Attachment E includes the detail of internal labor included in Table 1.

Portions of this inquiry and response, Attachments B1, B2, C and D are marked as "Not-Public" because they include confidential contract and pricing terms as well as vendor detail or confidential Company sourcing policy information considered to be trade secret data as defined by Minn. Stat. § 13.37(1)(b). This information has independent economic value, from not being generally known to, and not being readily ascertainable by other parties, who could obtain economic value from its disclosure or use. The disclosure of this information could adversely impact contract negotiations, potentially increasing costs for these services for our customers. Thus, Xcel Energy maintains this information as a trade secret pursuant to Minn. Rule 7829.0500.

Attachments B1, B2 and C are marked as "Not-Public" in their entirety. Pursuant to Minn. R. 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material:** Attachment B1 is a collection of change orders to contracts between the Company and its vendors for 2017 work on TIMP and DIMP projects. Attachment B2 is a confidential internal document detailing Company supply chain operating requirements. Attachment C is a collection of contracts between the Company and its vendors for 2017 work on TIMP and DIMP projects.
2. **Authors:** The contract renewal documentation included in Attachment B1, the supply chain requirements document, and the contract collection included in Attachment C were drafted by Xcel Energy Services legal and sourcing personnel.
3. **Importance:** We protect these contract terms, as disclosure can adversely affect negotiations and increase costs for services.
4. **Date the Information was Prepared:** Attachments B1 and C were prepared for this response May 2018. Attachment B2 was published in January 2016.

Preparer:	Austin Kerns / Ryan Cummings
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Xcel Energy			
Docket No.:	G002/M-17-787		
Response To:	MN Department of Commerce	Information Request No.	63
Requestor:	Danielle Winner, Dorothy Morrissey		
Date Received:	June 7, 2018		

<u>Question:</u>

Topic:	Invoices, Cost Data
Reference(s):	IR 49 Response, Attachment A; IR 62 Response, Attachment E

Note that the Attachment to this IR is Trade Secret in its entirety.

A. Please provide copies of the invoices and work orders affiliated with each of the capital and O&M data entries listed in the trade secret Attachment A to this IR.

B. In IR 49 Response, Attachment A, in the tab labeled "2017 GUIC O&M Summary," the Company identified $3,444,087 of non-amortized O&M DIMP expenses. The Company also pointed out that the corresponding data produced a slightly higher figure of $3,502,807 due to mixed capital/O&M work orders being included in the O&M dataset.

In the data contributing to the $3.5 million figure, the Department observes the following cost elements: Contract Labor, Employee Expenses Meals, Employee Expenses Per Diem, License Fees and Permits, Materials, NonProd Bargaining Labor G1_OH Alloc, Non-Prod Labor Bargaining Benefit Grp 1, Other Compensation Craft Welfare Fund, Outside Vendor Contract, Overtime, Postage, Premium, Prod Labor Bargaining Benefit Group 1, Purchasing-Overhead, Purchasing_OH Allocation, Transportation Fleet Cost, Warehouse – Overhead, Warehouse Energy Supply_OH Allocation, and Warehouse_OH Allocation.

Of the above-listed cost elements, the Department understands how License Fees and Permits, Materials, and Outside Vendor Contract costs (approximately $3.25 million) would be incremental to costs already captured in base rates. However, it is unclear how the remaining cost elements (totaling approximately $249,000) are incremental to costs captured in base rates.

1. Please identify which O&M expenses have mixed O&M/capital w work orders.
2. Please demonstrate how the approximately $249,000 corresponding to the above-referenced cost elements (all but License Fees and Permits, Materials, and Outside Vendor Contract) are costs that are incremental to costs captured in base rates.

C. In response to IR 62, the Company provided the Department with a live workbook, Attachment E. Please explain how the figures in the tab labeled "D-2017 GUIC RWIP" were reached.

D. In IR 62 Response, Attachment E, tab A-2017 GUIC by Cost Element, approximately $6 million in capital expenditure projects have one or more of the following labels:

Asset Type: "Gas New Business"

Program Type: "Gas New Service"

Expenditure Type: "Non-Trans New Main," "Gas Trans New Main," and "New Main."

These descriptions used for such projects are distinguished from other projects labeled as "Renewal" or "Replacement" within same spreadsheet, which indicates that projects labeled "new" must not be a type of replacement. The GUIC statute specifies that gas utility projects are "replacement" and "modification" of old equipment, and may not connect new customers or add new revenue. For each of the projects with the "new" labels, please demonstrate (1) how they are eligible as a GUIC project under the statute, or (2) that they are not included in the Company's GUIC-eligible projects.

E. In the Company's response to IR 62, in Attachment E, the Company states that approximately $7,787,033 of total GUIC expenditures (before ineligible expenditures are backed out) are attributable to Materials, Transportation, Construction Overhead, and Other Outside Services, and that these services are not traceable to vendor master service agreements. The Company also stated that a portion of these costs "relate to internal labor."

1. Please identify which expenditures that have a Resource Group of Materials, Transportation, Overhead, or Other are for internal labor.

2. Please identify which expenditures that have a Resource Group of Materials, Transportation, Overhead, or Other have been backed out of the Company's calculation of GUIC-eligible capital expenditures.
3. For any expenditures with a Resource Group of Overhead that are not considered internal labor, please explain why non-internal overhead costs do not trace back to a master contract.
4. The Department observes approximately $5,000 costs with a Resource Group of Other have Cost Elements related to various Employee Expenses. Please demonstrate that these employee expenses are above and beyond the representative allowance included in the Company's last rate case.

<u>Response:</u>

A. Please note: We will supplement this response with the Company's Attachment A, which will provide information regarding invoices and work orders affiliated with each of the capital and O&M data entries listed in the Department of Commerce's Attachment A to this inquiry, and we will also then provide Attachment B, which will include copies of the listed invoices.

B-1. To clarify, the difference between the figures of $3,444,087 and $3,502,807 of non-amortized O&M DIMP expenses listed in the Company's response to DOC IR 49, Attachment A is due to non-GUIC recoverable internal labor related to the Sewer Conflict Investigation Program (WBS A.0008410.163.001.004 and A.0008510.114.001.002), as shown in Attachment C to the present response. Attachment C is provided in live Excel spreadsheet format.

The O&M expenses resulting from mixed capital/O&M work orders totaled $15,978.61. Cost and accounting details of these amounts are provided in Attachment C to this response. These expenses were not included in the DIMP O&M expenses of $3,444,087 and $3,502,807 in the response to DOC IR 49, Attachment A, and they are not part of the Company's GUIC request.

B-2. Our current base rates were approved in our previous general gas rate case, Docket No. G002/GR-09-1153. The approved revenue requirements were based on a 2010 test year that did not include any O&M costs for DIMP activities. The 2010 test year included O&M cost elements shown in our response to DOC IR 49; however these O&M costs levels were intended for non-DIMP related work. Since there is no DIMP work intended in the cost estimates used to develop our current base rates; all of the DIMP costs shown in our response to DOC IR 49 are incremental to the base rate cost levels.

C. The Company identifies these amounts through our capital asset accounting system. As an asset is being constructed, costs are charged against a specific work order, and for each work order there is a unit estimate set up by the project engineer. A percentage split between CWIP and RWIP for the project is assigned to each unit estimate. The Company uses this unit estimate to split actual expenditures between CWIP and RWIP. The revenue requirement calculation picks up both the CWIP and RWIP items for rider eligible projects for inclusion in the GUIC rider.

D. An Asset Type of "Gas New Business", Program Type of "Gas New Service", or Expenditure Type of "Non-Trans New Main", "Gas Trans New Main", and "New Main" does not specifically mean that those assets are used for serving new customers. They refer to the installation of new assets that are not retiring assets of the same type. For instance, a distribution main replacing an existing distribution main would be classified as a "Main Renewal" since there is an asset of like-type being installed and retired. In the case of some GUIC projects, existing Transmission or Non-Transmission Assets are being replaced with distribution assets. In this case, a "New Main" of the distribution asset class is installed and no distribution assets are being retired. In other cases such as the installation of 4-inch and 6-inch emergency valves, the valve asset on the main did not exist, so a "New Main" asset is installed. If no valve was existing, there is no asset to specifically "Renew."

The $6 million figure referenced in the question is comprised of five projects that relate to the replacement of transmission assets with distribution assets and three projects that relate to the installation of new distribution valves: These projects are listed in the table below. GUIC recovery of projects for the replacement of transmission assets with distribution assets is permissible per Minn. Stat. § 216B.1635, subd. 1(c)(2), and recovery of new distribution valve projects is allowable per Minn. Stat. § 216B.1635, subd. 1(b)(3).

WBS 2	Parent	Parent Descr	Sub-Projects
Transmission Asset Replacements with Distribution			
E.0000004.019	11649797	TL0206 High Bridge Lateral Replacement	High Bridge Lateral Replacement
E.0000009.018	34000342	TL0206 High Bridge Lateral Replacement	High Bridge Lateral Replacement
E.0000004.048	34003261	NSPM Trans and IP Pipe	Montreal/Island Line Replacement
E.0000004.064	11810375	Repl 12in Upper 55 to S. St. Paul Reg Stat	Crossover Line
E.0000030.004	12013233	East Metro Pipeline Repl Regr Station Install	East Metro Replacement Project
Installation of New Distribution Valves			
E.0010011.005	50000646	NSPM Install 6" and 4" Distribution Valves	Distribution Valve Installation
E.0000004.075	11649520	NSPM Install 6" and 4" Distribution Valves	Distribution Valve Installation
E.0000004.054	11649520	NSPM Install 6" and 4" Distribution Valves	Distribution Valve Installation

E-1. Within the "Materials, Transportation, Overhead, or Other" resource groups, overhead includes a small amount of costs for internal labor identified by the cost element (approximately $100 in the Company's response to DOC IR 62, Attachment E). However, while included in this resource group, the revenue requirement model specifically identifies internal labor by cost element and excludes all internal labor from the revenue requirement calculation. Please see Attachment D to the present response. Attachment D is provided in live Excel spreadsheet format.

E-2. Within the "Materials, Transportation, Overhead, or Other" resource groups, costs related to the Sartell Betterment 28.1 percent not eligible for recovery has been backed out (approximately $49,000 are backed out and included in the overall Sartell Betterment Removal). Please see Attachment D.

E-3. Overhead cost (or indirect costs) allocation is a method of allocating costs that are incurred in normal business but cannot be directly assigned to a particular function or activity without excessive cost for the benefit received. These expenses are assigned to all functions using an allocation method. Each capital work order install or removal is assigned an overhead code. This code determines the type of overhead costs the project receives. This policy reflects consistent accounting that complies with FERC guidelines and SEC regulations for the addition of overhead costs to capital assets across all Xcel Energy utility subsidiary companies. A majority of these charges are associated with internal costs only.

E-4. No costs are being recovered in our current base rates for DIMP work. As such the approximately $3,300 DIMP-related employee expenses for the Other resource group are incremental to base rate cost levels. Please see our response to Part B-2. above.

There was approximately $480,000 in annual O&M expenditures for TIMP related work included in our base rates approved in the last general gas rate case. These costs have been removed from our GUIC request. As such all TIMP costs included in our request are incremental to costs levels recovered in our base rates. As such any of the approximately $1,300 in employee expenses for the Other resource group are incremental to our base rate cost levels.

Attachments A and B to this response are marked as "Not-Public" because they include confidential contract and pricing terms as well as vendor detail considered to be trade secret data as defined by Minn. Stat. § 13.37(1)(b). This information has independent economic value, from not being generally known to, and not being readily ascertainable by other parties, who could obtain economic value from its disclosure or use. The disclosure of this information could adversely impact contract negotiations, potentially increasing costs for these services for our customers. Thus, Xcel Energy maintains this information as a trade secret pursuant to Minn. Rule 7829.0500.

Attachments A and B are marked as "Not-Public" in their entirety. Pursuant to Minn. R. 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material:** Attachment A is a list of vendor invoice and Company payment information for work on a selected group of capital and O&M TIMP and DIMP projects. Attachment B is a collection of copies of invoices listed in Attachment A.
2. **Authors:** The invoice information was prepared by Xcel Energy sourcing and distribution finance personnel.
3. **Importance:** We protect this invoicing information, as disclosure can adversely affect negotiations and increase costs for services.
4. **Date the Information was Prepared:** Attachments A and B were prepared for this response in June 2018.

Preparer: Austin Kerns / Brandon Kirschner / Ryan Cummings
Title: Manager / Policy Specialist / Sr. Accounting Analyst
Department: Gas System Strategy & Bus Ops / NSPM Reg / Rev Requirements North
Telephone: (303) 571-7666 / (612) 215-5361 / (612) 330-1958
Date: June 18, 2018

Table 1. Contract Jurisdiction (PUBLIC)

Vendor	Contract	Effective Date	Emptoris/Other Number	Contract or Master Agreement Number (Passport)	Work Order Numbers	Xcel Affiliates in Contract	Geographic Scope of Work	Pricing Schedules Included
						NSP-MN	MN, ND	
					293978 (NSP-MN) 293979 (NSP-WI) 293980 (PSCo)	NSP-MN, NSP-WI, PSCo	MN, ND, WI, CO	NSP, PSCo
					331053 (NSP-MN) 331054 (NSP-WI) 331055 (PSCo)	NSP-MN, NSP-WI, PSCo	MN, WI, CO	NSP, PSCo
						NSP-MN, NSP-WI		
					271512 (NSP-MN) 272164 (NSP-WI)	NSP-MN, NSP-WI	MN, ND, SD, WI	NSP-MN, NSP-WI
						NSP-MN, NSP-WI	MN, ND, WI	NSP-MN, NSP-WI
						NSP-MN, NSP-WI	MN, ND, WI	NSP-MN, NSP-WI
						NSP-MN, NSP-WI	MN, ND, WI	NSP-MN, NSP-WI
						NSP-MN, NSP-WI, PSCo, SW PSC-NM		NSP, PSCo
					369277	NSP-MN, NSP-WI, PSCo, SW PSC-NM		
						NSP-MN, NSP-WI, PSCo, SW PSC-NM		NSP, PSCo
					370422 28106	NSP-MN, NSP-WI, PSCo, SW PSC-NM		
						NSP-MN, NSP-WI, PSCo, SW PSC-NM		
						NSP-MN		
						NSP-MN, NSP-WI, PSCo, SW PSC-NM		
						NSP-MN, NSP-WI, PSCo, SW PSC-NM		
						NSP-MN		
						NSP-MN, NSP-WI, PSCo, SW PSC-NM		
						NSP-MN, NSP-WI		
						NSP-MN and Xcel Energy Services Inc (DE)		
						NSP-MN, NSP-WI, PSCo, SW PSC-NM		
						NSP-MN, NSP-WI, PSCo, SW PSC-NM		
						NSP-MN, NSP-WI, PSCo, SW PSC-NM		
						PSCo		
						NSP-MN, NSP-WI		
						NSP-MN		
						NSP-MN, NSP-WI, PSCo, SW PSC-NM, Xcel (DE)		
						NSP-MN		
						NSP-MN		
						NSP-MN, NSP-WI, PSCo, SW PSC-NM, Xcel (DE)		
						NSP-MN, NSP-WI, PSCo, SW PSC-NM		
						NSP-MN, NSP-WI, PSCo		
						NSP-MN, NSP-WI		
						NSP-MN		
						NSP-MN, NSP-WI, PSCo, SW PSC-NM, Xcel (DE)		
	Work not in MN- proposed for removal							
	non-contract vendor							
	non-contract vendor							
	non-contract vendor							
	Work not in MN- proposed for removal							

Table 2. Data Jurisdiction (PUBLIC)

Vendor	Emptoris/Other Number	Contract or Master Agreement Number (Passport)	Work Order Numbers	Data Discrepancies	Amount in "Capital Data"	Amount in O&M Data	MN Work?
					21,686	2,960,275	Cap work appears to be MN, O&M Work unclear
			293978 (NSP-MN) 293979 (NSP-WI) 293980 (PSCo)		3,784,928	79,160	Appears to be all MN
			331053 (NSP-MN) 331054 (NSP-WI) 331055 (PSCo)		359,833	23,294	Appears to be all MN
					35,676	9,442	Appears to be all MN
			271512 (NSP-MN) 272164 (NSP-WI)		8,295,196	1,206,494	Appears to be all MN
				Two different contracts provided for vendor, neither of which have a passport number that match the data (393141)	3,719,656		Appears to be all MN
						1,531	Appears to be all MN
					24,365		Appears to be all MN
				Data has different passport number from contract (355435)	77,933		Appears to be all MN
			369277		219,359		Appears to be all MN
				Two different contracts provided for vendor, neither of which have a passport number that match the data (393141)	-		n/a
			370422 28106		1,049,726		Appears to be all MN
					256,079		Appears to be all MN
					308,563		Appears to be all MN
				Two different contracts provided for vendor, neither of which have a passport number that match the data (393399)	116,199		Appears to be all MN
					1,368		Appears to be all MN
					5,077		Appears to be all MN
					96,720		Appears to be all MN
				passport number not in contract, only data	30,148		Appears to be all MN
					552		Appears to be all MN
					48,572		Appears to be all MN
					11,760		Appears to be all MN
					14,450		Appears to be all MN
							n/a
					4,958		Appears to be all MN
				different company names for same contract numbers		1,499	Appears to be all MN
					513,752		Appears to be all MN
						2,945	Appears to be all MN

					1,396	5,799	Cap work appears to be MN, O&M Work unclear
				no passport number in contract		6,550	unlcear
					106		Appears to be all MN
					2,475		Appears to be all MN
					7,735		Appears to be all MN
					22,216		Appears to be all MN
					5,936		Appears to be all MN
					4,012		Work not in MN- proposed for removal
	non-contract vendor				10,230	10,230	Appears to be all MN
	non-contract vendor				6,754		Appears to be all MN
	non-contract vendor				175		Appears to be all MN
					450		Work not in MN- proposed for removal

Table 3. Jurisdictionally Unclear Data (PUBLIC)

Contract No.	Vendor	Filing Order with Name	Posting Date	Cost element descr.	Name	Vbl. value/Obj. curr	Order	CO object name	WBS Name	WBS LV 2 name
		12440381-SEWER REPAIR - GUIC RELATED	1/5/2017	Outside Vendor Contract		677.50	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	1/5/2017	Outside Vendor Contract		620.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	1/17/2017	Outside Vendor Contract		677.50	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	1/17/2017	Outside Vendor Contract		677.50	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	1/17/2017	Outside Vendor Contract		562.50	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12285039-16 SEWER MITIGATION - DIMP / GUIC -	1/22/2017	Outside Vendor Contract		8,255.33	200002198915	CONTRACTOR COSTS - SERVICES	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	1/22/2017	Outside Vendor Contract		1,370.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	1/22/2017	Outside Vendor Contract		895.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	1/26/2017	Outside Vendor Contract		1,630.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	1/26/2017	Outside Vendor Contract		1,105.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	1/26/2017	Outside Vendor Contract		1,000.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	1/26/2017	Outside Vendor Contract		1,210.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	1/26/2017	Outside Vendor Contract		6,841.19	200002575565	CONTRACTOR COSTS - SERVICES	MNGUIC -	MN GUIC
		12440381-SEWER REPAIR - GUIC RELATED	2/5/2017	Outside Vendor Contract		1,105.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	2/5/2017	Outside Vendor Contract		790.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	2/5/2017	Outside Vendor Contract		685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	2/5/2017	Outside Vendor Contract		895.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	2/5/2017	Outside Vendor Contract		562.50	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	2/5/2017	Outside Vendor Contract		505.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	2/5/2017	Outside Vendor Contract		7,054.86	200002575565	CONTRACTOR COSTS - SERVICES	MNGUIC -	MN GUIC
		12440381-SEWER REPAIR - GUIC RELATED	2/19/2017	Outside Vendor Contract		1,105.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	2/19/2017	Outside Vendor Contract		1,000.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	2/19/2017	Outside Vendor Contract		1,210.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	2/19/2017	Outside Vendor Contract		895.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	2/19/2017	Outside Vendor Contract		1,210.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	2/19/2017	Outside Vendor Contract		895.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	2/19/2017	Outside Vendor Contract		790.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	2/19/2017	Outside Vendor Contract		7,401.71	200002575565	CONTRACTOR COSTS - SERVICES	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	2/19/2017	Outside Vendor Contract		5,850.11	200002575565	CONTRACTOR COSTS - SERVICES	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	3/1/2017	Outside Vendor Contract		6,076.62	200002575565	CONTRACTOR COSTS - SERVICES	MNGUIC -	MN GUIC
		12440381-SEWER REPAIR - GUIC RELATED	3/1/2017	Outside Vendor Contract		1,945.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	3/1/2017	Outside Vendor Contract		1,945.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	3/1/2017	Outside Vendor Contract		790.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	3/1/2017	Outside Vendor Contract		1,420.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	3/2/2017	Outside Vendor Contract		1,370.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	3/2/2017	Outside Vendor Contract		1,315.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	3/21/2017	Outside Vendor Contract		685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	3/12/2017	Outside Vendor Contract		1,105.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	3/12/2017	Outside Vendor Contract		1,000.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	3/12/2017	Outside Vendor Contract		1,105.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	3/12/2017	Outside Vendor Contract		6,778.12	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12440381-SEWER REPAIR - GUIC RELATED	3/28/2017	Outside Vendor Contract		790.00	200002485112	CONTRACTOR REPAIRS TO MAIN SEWER LATERA	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	3/28/2017	Outside Vendor Contract		790.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	3/28/2017	Outside Vendor Contract		685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	3/28/2017	Outside Vendor Contract		685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	3/28/2017	Outside Vendor Contract		580.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	3/28/2017	Outside Vendor Contract		790.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	3/28/2017	Outside Vendor Contract		15,905.40	200002575565	CONTRACTOR COSTS - SERVICES	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	3/28/2017	Outside Vendor Contract		6,937.28	200002575565	CONTRACTOR COSTS - SERVICES	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	3/31/2017	Outside Vendor Contract		10,760.98	200002575565	CONTRACTOR COSTS - SERVICES	MNGUIC -	MN GUIC
		12440381-SEWER REPAIR - GUIC RELATED	3/31/2017	Outside Vendor Contract		790.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	5/10/2017	Outside Vendor Contract		685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	3/31/2017	Outside Vendor Contract		1,000.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	3/31/2017	Outside Vendor Contract		895.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	4/11/2017	Outside Vendor Contract		895.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	4/11/2017	Outside Vendor Contract		1,050.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	4/11/2017	Outside Vendor Contract		1,000.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	4/11/2017	Outside Vendor Contract		1,000.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	4/11/2017	Outside Vendor Contract		25,357.54	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	4/13/2017	Outside Vendor Contract		47,821.96	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12440381-SEWER REPAIR - GUIC RELATED	4/17/2017	Outside Vendor Contract		790.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	4/13/2017	Outside Vendor Contract		895.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	4/13/2017	Outside Vendor Contract		1,210.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	4/13/2017	Outside Vendor Contract		790.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	4/13/2017	Outside Vendor Contract		895.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	4/13/2017	Outside Vendor Contract		790.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	4/17/2017	Outside Vendor Contract		685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	4/17/2017	Outside Vendor Contract		685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	4/17/2017	Outside Vendor Contract		895.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	4/25/2017	Outside Vendor Contract		685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	4/25/2017	Outside Vendor Contract		895.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	4/25/2017	Outside Vendor Contract		1,000.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	4/25/2017	Outside Vendor Contract		24,851.80	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	5/1/2017	Outside Vendor Contract		34,195.28	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12440381-SEWER REPAIR - GUIC RELATED	5/1/2017	Outside Vendor Contract		790.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	5/1/2017	Outside Vendor Contract		790.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	5/1/2017	Outside Vendor Contract		677.50	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	5/4/2017	Outside Vendor Contract		790.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	5/4/2017	Outside Vendor Contract		685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	5/14/2017	Outside Vendor Contract		284.84	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	5/14/2017	Outside Vendor Contract		142.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	5/23/2017	Outside Vendor Contract		685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	5/23/2017	Outside Vendor Contract		790.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	5/29/2017	Outside Vendor Contract		1,000.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	6/4/2017	Outside Vendor Contract		35,043.37	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	6/4/2017	Outside Vendor Contract		57,961.71	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	6/4/2017	Outside Vendor Contract		29,655.09	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	6/4/2017	Outside Vendor Contract		88,053.26	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	6/4/2017	Outside Vendor Contract		63,149.69	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12440381-SEWER REPAIR - GUIC RELATED	6/4/2017	Outside Vendor Contract		1,420.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	6/4/2017	Outside Vendor Contract		1,000.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	6/4/2017	Outside Vendor Contract		895.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	6/4/2017	Outside Vendor Contract		580.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	6/4/2017	Outside Vendor Contract		685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	6/4/2017	Outside Vendor Contract		580.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	7/21/2017	Outside Vendor Contract		69,684.69	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	6/26/2017	Outside Vendor Contract		92,219.95	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	6/26/2017	Outside Vendor Contract		86,794.47	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	6/26/2017	Outside Vendor Contract		176.24	200002575565	CONTRACTOR COSTS - SERVICES	MNGUIC -	MN GUIC
		12440381-SEWER REPAIR - GUIC RELATED	6/26/2017	Outside Vendor Contract		1,000.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	6/26/2017	Outside Vendor Contract		790.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	6/26/2017	Outside Vendor Contract		790.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	6/26/2017	Outside Vendor Contract		580.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	6/26/2017	Outside Vendor Contract		580.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	6/26/2017	Outside Vendor Contract		790.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	6/26/2017	Outside Vendor Contract		1,000.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	6/26/2017	Outside Vendor Contract		685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	6/26/2017	Outside Vendor Contract		790.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	7/21/2017	Outside Vendor Contract		86,317.20	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12440381-SEWER REPAIR - GUIC RELATED	7/21/2017	Outside Vendor Contract		895.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	7/21/2017	Outside Vendor Contract		895.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	7/21/2017	Outside Vendor Contract		580.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	7/21/2017	Outside Vendor Contract		176.24	200002575565	CONTRACTOR COSTS - SERVICES	MNGUIC -	MN GUIC
		12440381-SEWER REPAIR - GUIC RELATED	7/21/2017	Outside Vendor Contract		685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	7/21/2017	Outside Vendor Contract		95,702.77	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	7/21/2017	Outside Vendor Contract		88,124.92	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	7/21/2017	Outside Vendor Contract		66,218.68	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12440381-SEWER REPAIR - GUIC RELATED	7/21/2017	Outside Vendor Contract		895.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	7/21/2017	Outside Vendor Contract		685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	7/21/2017	Outside Vendor Contract		580.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	7/21/2017	Outside Vendor Contract		895.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	7/31/2017	Outside Vendor Contract		102,765.21	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12440381-SEWER REPAIR - GUIC RELATED	7/31/2017	Outside Vendor Contract		685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	7/31/2017	Outside Vendor Contract		580.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	8/15/2017	Outside Vendor Contract		90,876.67	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	8/15/2017	Outside Vendor Contract		108,099.31	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12440381-SEWER REPAIR - GUIC RELATED	8/15/2017	Outside Vendor Contract		580.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	8/15/2017	Outside Vendor Contract		580.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	8/28/2017	Outside Vendor Contract		87,973.75	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	8/31/2017	Outside Vendor Contract		84,876.03	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12440381-SEWER REPAIR - GUIC RELATED	8/30/2017	Outside Vendor Contract		685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	9/6/2017	Outside Vendor Contract		105,445.35	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12440381-SEWER REPAIR - GUIC RELATED	9/8/2017	Outside Vendor Contract		685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009

		12440381-SEWER REPAIR - GUIC RELATED	9/8/2017	Outside Vendor Contract	620.00	200002485112	CONTRACTOR REPAIRS TO MAIN SEWER LATERA	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	9/8/2017	Outside Vendor Contract	790.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	9/8/2017	Outside Vendor Contract	89,859.42	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	9/15/2017	Outside Vendor Contract	82,444.87	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	9/27/2017	Outside Vendor Contract	90,659.76	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12440381-SEWER REPAIR - GUIC RELATED	9/25/2017	Outside Vendor Contract	620.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	9/25/2017	Outside Vendor Contract	685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	9/25/2017	Outside Vendor Contract	790.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	10/2/2017	Outside Vendor Contract	97,523.83	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12440381-SEWER REPAIR - GUIC RELATED	10/2/2017	Outside Vendor Contract	685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	10/4/2017	Outside Vendor Contract	685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	10/7/2017	Outside Vendor Contract	125,654.90	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12440381-SEWER REPAIR - GUIC RELATED	10/16/2017	Outside Vendor Contract	685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	10/16/2017	Outside Vendor Contract	685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	10/16/2017	Outside Vendor Contract	790.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	10/20/2017	Outside Vendor Contract	96,012.28	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	10/23/2017	Outside Vendor Contract	103,759.63	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12440381-SEWER REPAIR - GUIC RELATED	10/23/2017	Outside Vendor Contract	685.00	200002485112	CONTRACTOR REPAIRS TO MAIN SEWER LATERA	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	10/23/2017	Outside Vendor Contract	580.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	10/23/2017	Outside Vendor Contract	685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	10/23/2017	Outside Vendor Contract	685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	10/23/2017	Outside Vendor Contract	685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	10/23/2017	Outside Vendor Contract	790.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	10/30/2017	Outside Vendor Contract	114,448.05	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	11/13/2017	Outside Vendor Contract	101,803.98	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	11/13/2017	Outside Vendor Contract	123,240.59	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12440381-SEWER REPAIR - GUIC RELATED	11/13/2017	Outside Vendor Contract	685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	11/13/2017	Outside Vendor Contract	580.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	11/13/2017	Outside Vendor Contract	580.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	11/13/2017	Outside Vendor Contract	685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	11/13/2017	Outside Vendor Contract	685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	11/13/2017	Outside Vendor Contract	580.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	11/13/2017	Outside Vendor Contract	685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	11/21/2017	Outside Vendor Contract	99,054.40	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	11/21/2017	Outside Vendor Contract	79,738.75	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12440381-SEWER REPAIR - GUIC RELATED	11/21/2017	Outside Vendor Contract	685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	11/21/2017	Outside Vendor Contract	580.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	11/21/2017	Outside Vendor Contract	475.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	11/10/2017	Outside Vendor Contract	3,275.00	200002575491	ENGINEERING - OTHER COSTS	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	12/12/2017	Outside Vendor Contract	3,275.00	200002575491	ENGINEERING - OTHER COSTS	MNGUIC -	MN GUIC
		12440381-SEWER REPAIR - GUIC RELATED	1/17/2017	Outside Vendor Contract	518.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	1/31/2017	Outside Vendor Contract	349.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	2/20/2017	Outside Vendor Contract	518.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	2/21/2017	Outside Vendor Contract	349.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	3/1/2017	Outside Vendor Contract	518.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	3/1/2017	Outside Vendor Contract	518.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	5/1/2017	Outside Vendor Contract	349.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	5/31/2017	Outside Vendor Contract	518.00	200002485112	CONTRACTOR REPAIRS TO MAIN SEWER LATERA	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	7/10/2017	Outside Vendor Contract	777.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	10/2/2017	Outside Vendor Contract	518.00	200002485112	CONTRACTOR REPAIRS TO MAIN SEWER LATERA	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	10/13/2017	Outside Vendor Contract	349.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	11/6/2017	Outside Vendor Contract	518.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	1/29/2017	Outside Vendor Contract	1,499.46	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	9/15/2017	Outside Vendor Contract	349.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	11/6/2017	Outside Vendor Contract	-349.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12411154-TL0209 / E COUNTY LINE CASING PRES	4/28/2017	Outside Vendor Contract	20,000.00	200002436291	OUTSIDE SERVICES	MNGUIC -	MNGUIC - 1009
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	12/2/2017	Outside Vendor Contract	250.20	200002575491	ENGINEERING - OTHER COSTS	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	8/31/2017	Outside Vendor Contract	136.35	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	3/7/2017	Outside Vendor Contract	75.85	200002575491	ENGINEERING - OTHER COSTS	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	3/7/2017	Outside Vendor Contract	40.25	200002575491	ENGINEERING - OTHER COSTS	MNGUIC -	MN GUIC
		200002062451-Mapping-880771-880771	8/31/2017	Outside Vendor Contract	-361.96	200002062451	Mapping-880771-880771	Table 11-101	Table 11-1012-0010

Table 4. Audit of Capital Invoice/Work Order Jurisdiction (PUBLIC)

Contract No.	Vendor	Purchasing Doc/Contract Auth.	Filing Order with Name	Posting Date	Cost element descr.	Vbl. value/Obj. curr	MN Jurisdiction on Invoice Copy
			100362538-Montreal Line S Renewal - Construction	12/7/2017	Service Consumption	1,954,069.82	confirmed
			100404773-Island Line S Renewal - Construction	12/13/2017	Service Consumption	799,717.61	confirmed
			100404773-Island Line S Renewal - Construction	12/15/2017	Service Consumption	772,760.38	confirmed
			12403875-SARTELL RIVER CROSSING / GAS MAIN RE-INFORCEMENT	2/1/2017	Outside Vendor Contract	609,695.58	confirmed
			11818868-EAST METRO PIPELINE REPLACEMENT PROJECT (2016 INSTALLATION)	4/30/2017	Outside Vendor Contract	233,650.25	confirmed
			12403875-SARTELL RIVER CROSSING / GAS MAIN RE-INFORCEMENT	3/28/2017	Outside Vendor Contract	210,256.00	confirmed
			12505914-WINONA-3RD ST. BTN. WINONA ST. & LIBERTY ST.-2017 DIMP	8/16/2017	Outside Vendor Contract	139,215.19	confirmed
			11818868-EAST METRO PIPELINE REPLACEMENT PROJECT (2016 INSTALLATION)	6/20/2017	Outside Vendor Contract	120,086.75	confirmed
			12359008-IMP - TL0206 ISLAND LINE SOUTH MAKE PIGGABLE	1/9/2017	Outside Vendor Contract	112,192.87	confirmed
			11818868-EAST METRO PIPELINE REPLACEMENT PROJECT (2016 INSTALLATION)	7/25/2017	Outside Vendor Contract	108,219.92	confirmed
			100404773-Island Line S Renewal - Construction	12/17/2017	Service Consumption	103,783.23	confirmed
			12526379-INSTALL NEW MONTREAL LINE SOUTH	11/7/2017	Outside Vendor Contract	56,505.49	confirmed
			100382714-01432348 NO ST PAUL 18TH AVE INSTALL 560	10/20/2017	Outside Vendor Contract	19,597.48	confirmed
			12531351-COLBY LAKE LATERAL RENEWAL (WOODLANE TO COLBY LK)	11/29/2017	Outside Vendor Contract	17,333.01	confirmed
			12356426-JSW:LKC:DIMP:LAKEWOOD AVE: RENEW PEA MAIN	10/23/2017	Outside Vendor Contract	16,763.43	confirmed
			12359008-IMP - TL0206 ISLAND LINE SOUTH MAKE PIGGABLE	7/21/2017	Outside Vendor Contract	15,262.67	confirmed
			12366775-IMP - TL0200 ROSEMOUNT LINE INVER HILLS LATERAL ILI	11/20/2017	Outside Vendor Contract	13,052.50	confirmed
			12356426-JSW:LKC:DIMP:LAKEWOOD AVE: RENEW PEA MAIN	12/15/2017	Outside Vendor Contract	10,164.20	confirmed
			12523417-CROSSOVER LINE RELOCATION PROJECT (UPPER 55 TO SSTP ST)	10/19/2017	Outside Vendor Contract	9,385.05	confirmed
			12364289-RCV ACTUATOR INSTALLATION - LAKE ELMO 1B TBS	1/31/2017	Outside Vendor Contract	3,746.02	confirmed
			12320752-ST. PAUL-ETNA-BIRMINGHAM-WINCHELL BTN HOYT & ARLINGTON-2016	11/30/2017	Outside Vendor Contract	-7,686.58	confirmed
			12526379-INSTALL NEW MONTREAL LINE SOUTH	10/7/2017	Outside Vendor Contract	-11,784.94	not applicable
			12364484-IMP - TL0209 E COUNTY LINE CASING REMOVAL	4/28/2017	Outside Vendor Contract	-20,000.00	not applicable
			12344852-ROSEVILLE/ CO RD C PROJECT/ INSTALL 19850' OF 2" & 3550' 4"	4/27/2017	Service Consumption	-21,400.00	confirmed
			12317856-SHOREVIEW/ NANCY PL/ INSTALL 7600' OF 2" PE MAIN	1/30/2017	Outside Vendor Contract	-29,397.60	confirmed

Table 5. Audit of O&M Invoice/Work Order Jurisdiction (PUBLIC)

Posting Date	Cost element descr.	Name	Vbl. value/Obj. curr	CO object name	MN Jurisdiction on Invoice Copy?
2/1/2017	Outside Vendor Contract	03512024~UMN0760803 WALKER 01/06/17 1/26/17	609,695.58	SARTELL RIVER CROSSING / GAS MAIN RE-INF	confirmed
2/28/2017	Engineering and Super - Overhead	MN-E&S-Gas Dist	320,588.47	SARTELL RIVER CROSSING / GAS MAIN RE-INF	not applicable
7/1/2017	Outside Vendor Contract	FERC 874 - Sewer Conflict Amor	292,886.62	Sewer Conflict Amort-Dist Op Mains&Svcs	not applicable
5/1/2017	Outside Vendor Contract	FERC 874 - Sewer Conflict Amor	292,886.62	Sewer Conflict Amort-Dist Op Mains&Svcs	not applicable
5/31/2017	Outside Vendor Contract	NNNL01 accrual 5/2017	143,746.67	CONTRACTOR COSTS - MAINS	confirmed
5/31/2017	Outside Vendor Contract	NNNL01 accrual 5/2017	130,116.44	CONTRACTOR COSTS - SERVICES	confirmed
6/30/2017	Contract Outside Vendors-Settle_Indir		83,815.20	CONTRACTOR COSTS - SERVICES	confirmed
12/31/2017	Outside Vendor Contract	t3088 Dec Q3 - 2 Accruals	45,000.00	SLEEVE RISER / ST CLOUD RISER SLEEVES 20	confirmed
5/31/2017	Outside Vendor Contract	tc258 CPA accrual May 2017 co10	44,075.20	SLEEVE RISER / ST CLOUD RISER SLEEVES 20	confirmed
8/31/2017	Purchasing_OH Allocation	200031 Purch Overhead Load-Alloc	10,361.20	CONTRACTOR COSTS - MAINS	not applicable
3/13/2017	Materials	MANAGED SERVICES 03/01/1	3,275.00	ENGINEERING - OTHER COSTS	unclear
11/10/2017	Outside Vendor Contract	DATA BASE MANAGEMENT 2010-2012 I	3,275.00	ENGINEERING - OTHER COSTS	unclear
6/1/2017	Outside Vendor Contract	NNNL01accrual 5/2017	-143,746.67	CONTRACTOR COSTS - MAINS	not applicable
9/30/2017	Contract Outside Vendors-Settle_Indir		-368,409.40	CONTRACTOR COSTS - MAINS	confirmed

CERTIFICATE OF SERVICE

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

Minnesota Department of Commerce
Public Comments

Docket No. G002/M-17-787

Dated this 2nd day of July 2018

/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_17-787_M-17-787
Alison C	Archer	aarcher@misoenergy.org	MISO	2985 Ames Crossing Rd Eagan, MN 55121	Electronic Service	No	OFF_SL_17-787_M-17-787
Gail	Baranko	gail.baranko@xcelenergy.com	Xcel Energy	414 Nicollet Mall7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_17-787_M-17-787
Ryan	Barlow	Ryan.Barlow@ag.state.mn.us	Office of the Attorney General-RUD	445 Minnesota Street Bremer Tower, Suite 1400 St. Paul, Minnesota 55101	Electronic Service	No	OFF_SL_17-787_M-17-787
William A.	Blazar	bblazar@mnchamber.com	Minnesota Chamber Of Commerce	Suite 1500 400 Robert Street North St. Paul, MN 55101	Electronic Service	No	OFF_SL_17-787_M-17-787
John	Coffman	john@johncoffman.net	AARP	871 Tuxedo Blvd. St, Louis, MO 63119-2044	Electronic Service	No	OFF_SL_17-787_M-17-787
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_17-787_M-17-787
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_17-787_M-17-787
George	Crocker	gwillc@nawo.org	North American Water Office	PO Box 174 Lake Elmo, MN 55042	Electronic Service	No	OFF_SL_17-787_M-17-787
Carl	Cronin	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_17-787_M-17-787

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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_17-787_M-17-787
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_17-787_M-17-787
Edward	Garvey	garveyed@aol.com	Residence	32 Lawton St Saint Paul, MN 55102	Electronic Service	No	OFF_SL_17-787_M-17-787
Edward	Garvey	edward.garvey@AESLconsulting.com	AESL Consulting	32 Lawton St Saint Paul, MN 55102-2617	Electronic Service	No	OFF_SL_17-787_M-17-787
Todd J.	Guerrero	todd.guerrero@kutakrock.com	Kutak Rock LLP	Suite 1750 220 South Sixth Street Minneapolis, MN 554021425	Electronic Service	No	OFF_SL_17-787_M-17-787
Kimberly	Hellwig	kimberly.hellwig@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_17-787_M-17-787
Annete	Henkel	mui@mnutilityinvestors.org	Minnesota Utility Investors	413 Wacouta Street #230 St.Paul, MN 55101	Electronic Service	No	OFF_SL_17-787_M-17-787
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COMMERCE DEPARTMENT

July 3, 2018

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101-2147

RE: **Request for Acceptance of Late Filed Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. G002/M-17-787

Dear Mr. Wolf:

The Minnesota Department of Commerce, Division of Energy Resources (Department) respectfully requests that the Minnesota Public Utilities Commission (Commission) accept the Department's late-filed comments in this docket. We apologize that we did not file the Department's comments until after the 4:30PM deadline; hence the filing date for the comments is Tuesday, July 3, 2018.

Moreover, the Department made a few minor corrections to its Comments and requests that the corrected version be used, for clarity. The Department apologizes for any inconvenience and is available to answer any questions that the Commission may have.

Sincerely,

/s/ Dorothy Morrissey	/s/ Danielle Winner
Financial Analyst	Rates Analyst

DM/DW/ja

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
Request for Acceptance of Late-Filed Comments

Docket No. G002/M-17-787

Dated this 3rd day of July 2018

/s/Sharon Ferguson

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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_17-787_M-17-787

July 3, 2018 **PUBLIC DOCUMENT**

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101-2147

RE: **PUBLIC Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. G002/M-17-787

Dear Mr. Wolf:

Attached are the corrected **PUBLIC** 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 2016, Revenue Requirements for 2017, and Revised Adjustment Factors (*Petition*).

The *Petition* was filed on November 1, 2017 and supplemented on March 27, 2018 and May 29, 2018 by:

> Amy Liberkowski
> Manager, Regulatory Analysis
> Xcel Energy
> 414 Nicollet Mall, 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 the Commission may have.

Sincerely,

/s/ DOROTHY MORRISSEY
Rates Analyst

/s/ DANIELLE WINNER
Rates Analyst

DM/DW/ja
Attachment

Before the Minnesota Public Utilities Commission

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

Docket No. G002/M-17-787

I. BACKGROUND

The Gas Utility Infrastructure Cost (GUIC) Recovery Rider was established under Minn. Stat. § 216B.1635.[1] It allows natural gas utilities expedited recovery of certain projects between rate cases. Eligible projects can constitute either replacement or modification of 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 or the Company), filed its inaugural GUIC recovery petition requesting approval to establish a rider (2015 GUIC Rider). This request was the first GUIC recovery proposal before the Minnesota Public Utilities Commission (Commission) for rate treatment under Minn. Stat. § 216B.1635. On January 27, 2015, the 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.

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

On November 1, 2016, in Docket No. G002/M-16-891 (Docket 16-891), Xcel filed its most recently approved GUIC Rider petition, in which the Company requested approval of a 2017 GUIC Rider and a true up of its revenue requirements for 2017 (2017 GUIC Rider). On February 8, 2018, the Commission issued its *Order Approving Rider with Modifications*, in which the Commission approved the 2017 GUIC Rider petition with the following modifications:

[1] The GUIC statute was established in 2005 and amended in 2014.

- Approved an overall rate of return of 7.02 percent for the 2017 GUIC Rider;
- Rejected the Company's proposed level of distribution-related software costs in the 2017 GUIC Rider, and directed Xcel to adjust distribution-related software costs included in rate base for recovery through the 2017 GUIC Rider to $444,543;
- Rejected all Quality Assurance/Quality Control (QA/QC) related costs included in the 2017 GUIC Rider since they represent duplicative services;
- Accepted Xcel's cost/revenue study based on 2015 actuals, which the Commission directed the Company to perform in its 2016 GUIC Rider Order;
- Directed Xcel to, in future GUIC filings, continue to discuss with parties, including the Minnesota Department of Commerce, Division of Energy Resources (Department) and the Office of Attorney General (OAG), proposed performance metrics and ongoing evaluation of reporting requirements;
- Directed Xcel to continue to provide, in future GUIC Filings, specific information about each individual GUIC project;
- Denied Xcel's proposed Accumulated Deferred Income Tax (ADIT) proration for the forecasted year in the instant petition, and instead determined that Xcel's 2017 GUIC Rider must not be effective prior to January 1, 2018;
- Approved Xcel's revised sales forecast based on the Company's regression model before adjustments to monthly sales and demand-side management, as presented in Attachment F of Xcel's Reply Comments filed March 13, 2017 in Docket 16-891;
- Approved sewer conflict inspection program costs, and directed Xcel to provide a cost-benefit analysis of these costs in future GUIC filings;
- Approved $2,249,926 in distribution valve replacement project costs to be recovered through the 2017 GUIC; and
- Required Xcel to recover 2017 revenue requirements over the 12 months following the effective date of the order.

Xcel implemented its 2017 GUIC Rider beginning March 1, 2018, which, per the Commission-directed 12 month recovery period, will be in effect through the end of February, 2019. The 2017 GUIC Rider is set to recover the Company's 2017 revenue requirement, in addition to any carryover balance from the 2016 GUIC Rider.

Since the 2017 GUIC Order was released after Xcel filed this instant *Petition*, Xcel filed a Supplement on March 27, 2018 (*Petition Supplement*) in the instant *Petition* to incorporate the Commission's directives from the 2017 GUIC Rider Order. The Department's Comments respond to Xcel's *Petition*, as updated by the *Petition Supplement*.

The first Section of these Comments provides background, Section II provides a summary of the Company's *Petition*, and Section III provides the Department's Analysis of the *Petition*. Section IV responds to Xcel's May 29, 2018 supplemental comments, filed per Commission Notice, regarding rate treatment considerations with respect to expense reductions related to Xcel Gas' annual depreciation study approved in Docket No. E,G002/D-17-581. Finally, in Section V, the Department provides a summary of conclusions and recommendations, and recommends approval, with modification, of the current 2018 GUIC Rider proposal.

II. SUMMARY OF PETITION

Xcel's forecasted 2018 revenue requirement is $24.36 million, compared to the prior year's actual 2017 revenue requirement of $20.1 million. [2] The 2018 figure from the *Petition Supplement* incorporates the newly enacted federal tax rate and the Commission's 2017 GUIC Rider Order in Docket 16-891.

In previous Orders, the Commission approved recovery of a number of projects under Minn. Stat. § 216B.1635 (GUIC Statute). Xcel's individual projects fall into two major categories: transmission- and distribution-integrity management programs (TIMP and DIMP, respectively). These programs carry out pipeline risk mitigation requirements of the U.S. Department of Transportation (USDOT), and are overseen by its agency, the Pipeline and Hazardous Materials Safety Administration (PHMSA).

In the TIMP category, the following initiatives are underway or planned:

- **Transmission pipeline assessments,** including in-line inspections (ILI), pressure tests, and direct assessment;
- **Automatic-shutoff and remote-controlled valve installation,** allows more expedient gas shutoff in an emergency; and
- **Programmatic Replacement/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.

In the DIMP category, Xcel has undertaken or plans to undertake the following projects to assess and improve the integrity of its distribution assets:

[2] The GUIC revenue requirement calculations are shown in the *Petition Supplement*, Attachments N and O.

- **Poor-performing main and service-line replacement,** identify high-risk pipeline segments and prioritizing their replacement in concert with city and county road maintenance;
- **Intermediate-pressure line assessments,** determine the health and condition of medium-sized distribution pipelines,
- **Distribution-valve replacements,** maintain Xcel's ability to isolate sections of the system in case of an emergency;
- **Federal Code Mitigation (FCM)**, conduct field work to maintain compliance with Federal Code; FCM identified project work is expected to be completed in 2018; and
- **Sewer and gas line conflict-remediation program,** identify and correct situations where natural gas lines intersect with sewer lines; this project is expected to be completed in 2019.

Table 1 presents the Company's estimated expenditures for each of these programs, divided between capital expenditures and operations and maintenance (O&M) expenditures:

Table 1: Estimated 2018 TIMP and DIMP Expenditures by Program in Xcel Gas's *Petition*

	Program	**Capital Expenditures ($ millions)**	**Operations and Maintenance ($ millions)**
TIMP	Transmission Pipeline Assessments	$0.30	$1.51
	ASVs and RCVs	$1.00	$0
	Programmatic Replacement and MAOP Remediation	$8.00	$0
	Total TIMP	$9.30	$1.51
DIMP	Poor Performing Main Replacements	$11.05	$0
	Poor Performing Service Replacements	$6.91	$0
	Intermediate Pressure (IP) Line Assessments	$19.82	$1.03
	Distribution Valve Replacement Project	$0.50	$0
	Sewer and Gas Line Conflict Investigation	$0	$2.31
	Federal Code Mitigation	$0	$0.20
	Total DIMP	$38.28	$3.54
Total, Initial	All Program Expenditures, *Petition*	$47.58	$5.05
Total, Final	**All Program Expenditures, *Petition Supplement***	**$45.53**	**$4.86**

All individual program expenditures reflect the Company's initial filing. The Company appears to have updated certain expenditures between the time of the initial filing and the time of the *Petition Supplement*, but did not specify which specific programs were affected by the changes. Table 2 presents the Company's proposed 2018 GUIC revenue requirement:

Table 2: Total Proposed 2018 GUIC Revenue Requirement, *Petition Supplement*

Project	**2018 Capital ($ Millions)**	**2018 O&M ($ Millions)**
Total TIMP Incremental Revenue Requirements	9.15	1.33
Total DIMP Incremental Revenue Requirements	6.25	3.53
O&M in Base Rates	n/a	(0.48)
5-Year Amortization of Deferred TIMP and DIMP Costs[3]	$4.55	
Pro-rated ADIT	0.03	
Total 2017 Revenue Requirements Combined before True Up	$24.36	
True-Up Carryover from 2017	$0	
GUIC Total 2018 Revenue Requirements	**$24.36**	

More precisely, Xcel's proposed 2018 GUIC revenue requirements total $24,359,177.

Xcel proposed an implementation date of August 1, 2018 for the proposed 2018 GUIC Rider, and proposed recovering its 2018 revenue requirement by the end of March, 2019.[4] Since the currently approved 2017 GUIC Rider will be in place until February 28, 2019, this proposal means that the Company would overlap two different GUIC Rider recovery year's factors from August 1, 2018 through February 28, 2019. Essentially, the overlapped, separately-tracked factors would be recovering different periods' revenue requirements: the 2017 GUIC Rider would recover the 2017 revenue requirement, and the 2018 GUIC Rider would recover the 2018 revenue requirement. The Department responds to this proposal in Section III.F.2 of these comments.

Xcel proposed to allocate the revenue requirements within the 2018 GUIC Rider to its various customer classes in the same manner as revenue responsibilities were apportioned in its most recent natural gas rate case,[5] consistent with the Commission's previous GUIC orders.[6]

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[3] In the 2015 GUIC Order, the Commission allowed the Company to amortize recovery of GUIC-eligible costs incurred prior to the 2014 GUIC Statute amendments. These amortized costs will be recovered through 2019.
[4] *Petition,* Page 7.
[5] Docket No. G002/GR-09-1153.
[6] 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.

However, for purposes of the GUIC Rider, the Company groups different classes together to create five class groups. Xcel then calculated rates for each class group by dividing the class group's revenue responsibility by the forecasted Minnesota sales for each class group over the course of the proposed 8-month recovery period, August 1, 2018 through February 28, 2019 (2018 GUIC Class Factors).[7]

The GUIC Rider rate is part of the Resource Adjustment line on customer bills.[8] The figures in Table 3, columns A – C, demonstrate that the increases in the proposed 2018 GUIC Class Factors over the 2017 GUIC Class Factors alone range between a 94.6% increase to a 125.1% increase in this charge.[9] However, since the Company is proposing to overlap the 2017 and 2018 GUIC Riders (that is, charge both the 2017 and 2018 rates simultaneously), ratepayers would actually experience a greater increase, as shown in Table 3, columns D and E. The subsequent Table 4 shows the average bill impacts for those rates.

Xcel's proposed GUIC Class Factor calculations assume that the current 2017 GUIC Class Factors would remain in effect for a 12-month period, or through February 28, 2019, and that the proposed 2018 GUIC Class Factors would become effective August 1, 2018, but recover the 2018 revenue requirements over a 8-month period, through February 28, 2019.

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[7] In these Comments, the Department refers to the overall rider as the "GUIC Rider" and the rates charged to different customer groupings as "GUIC Class Factors."
[8] *Petition*, Page 37.
[9] The Department notes that though the 2018 GUIC revenue requirement ($24.36 million) is approximately 21 percent higher than the 2017 GUIC revenue requirement ($20.1 million), much of the comparative change in factor rates is due to Xcel's proposed use of a 8-month recovery period for the proposed 2018 revenue requirements.

Table 3: Percentage Increase from 2017 GUIC Class Factors to 2018 Class Factors, Overlapped 2017 and 2018 Class Factors

	2017 GUIC Rider (Docket 16-891)	**2018 GUIC Rider (Docket 17-787)**		**Overlapped 2017 and 2018 GUIC Riders**	
	A	B	C	D	E
	Approved 2017 Class Factors ($/therm)	Proposed [10] 2018 Class Factors ($/therm)	Percent Increase/ (Decrease) from 2017 Class Factors	Proposed Overlapping of 2017 and 2018 Class Factors ($/therm)	Percent Increase/ (Decrease) from 2017 Class Factors
Residential	0.027634	0.053784	94.6%	0.081419	194.6%
Commercial Firm	0.015080	0.030490	102.2%	0.045569	202.2%
Commercial Demand	0.011332	0.025143	121.9%	0.036475	221.9%
Interruptible	0.008114	0.018265	125.1%	0.026379	225.1%
Transport	0.003276	0.006870	109.0%	0.010157	209.0%

[10] *Petition Supplement*, Attachment Q

Table 4: Customer Bill Impacts - Percentage Increase from 2017 GUIC Class Monthly Bill to 2018 Class Monthly Bill, Overlapped 2017 and 2018 Class Monthly Bill

		2017 GUIC Rider (Docket 16-891)	**2018 GUIC Rider (Docket 17-787)**		**Overlapped 2017 and 2018 GUIC Riders**	
	Average Monthly Usage (therms)[11]	Current Monthly Bill due to 2017 GUIC	Proposed [12] Monthly Bill Increase due to 2018 GUIC	Percent Increase/ (Decrease) from 2017 Monthly Bill	Total Proposed Monthly Bill due overlapped 2017 and 2018 GUIC Riders	Percent Increase/ (Decrease) from 2017 Monthly Bill
Residential	70	$1.93	$3.76	94.6%	$5.70	194.6%
Commercial Firm	480	$7.24	$14.64	102.2%	$21.87	202.2%
Commercial Demand	16,990	$192.53	$427.18	121.9%	$619.71	221.9%
Interruptible	22,775	$184.80	$415.99	125.1%	$600.78	225.1%
Transport	663,538	$2,173.75	$4,558.51	109.0%	$6,732.26	209.0%

III. DEPARTMENT ANALYSIS

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 a 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.[13] The Department notes that the Commission interpreted this Statute in its January 27, 2015 *Order* in

[11] DOC IR No. 51.A included as DOC Attachment 2.
[12] *Petition Supplement*, Attachment Q.
[13] Minn. Stat. § 216B.1635, Subd. 1(b), (c).

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.[14]

A utility seeking approval of a GUIC Rider must file a petition with the Commission detailing the projects and costs proposed for recovery.[15] The petition for rate recovery is to be of only incremental costs.[16] 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.[17]

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.[18] Costs eligible for rider recovery include a rate of return, income

[14] Minn. Stat. § 216B.1635, Subd. 1(b) (3).
[15] *Id.*, Subd. 2-3.
[16] *Id.,* Subd. 2
[17] *Id.*, Subd. 4.
[18] *Id.,* Subd. 5.

taxes on the rate of return, incremental property taxes, incremental depreciation expense, and any incremental operation and maintenance costs.[19]

Xcel included a compliance matrix for the filing requirements specified in Minn. Stat. § 216B.1635 and in prior Commission orders (Attachment A to its initial *Petition*).
The Department concluded that Xcel Gas' filing reasonably complies with the filing requirements, with the exception of Minn. Stat. § 216B.1635, Subd. 4 (2) (iii), which reads:

> (2) a gas utility must file sufficient information to satisfy the commission regarding the proposed GUIC. The information includes, but is not limited to:
> …
> (iii) 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; [emphasis added]

Xcel's *Petition* omitted a report of the costs and salvage value associated with the existing infrastructure replaced or modified. Rather, Xcel's compliance matrix refers to Section IV.H of its petition where the Company provides estimated costs and salvage value of the new infrastructure projects it is undertaking, as complying with this statutory requirement.[20] The statute clearly requires the petitioners to provide this information on *existing infrastructure replaced or modified*. This required information would aid the Department in conducting its analysis. In fact, the Department raises issues related to the consideration of existing plant replaced/retired by GUIC projects in Section III.D.1 to which the upfront disclosure of such data would have been useful.

The Department requests that the Company file the required information in its Reply Comments. Also, the Department recommends that the Commission direct the Company to include such a report in future GUIC Rider petitions.

In addition to statutory filing requirements, prior Commission orders have required Xcel to include certain reports in its GUIC petitions. In its February 8, 2018 Order in Docket 16-891, the Commission directed Xcel to file a cost/benefit analysis of the sewer conflict inspection program in future GUIC petitions if the Company wishes to recover costs of the project through the rider mechanism. This directive was responsive to the Department's comments in that docket describing the challenges faced to obtain information to fully evaluate this particular program. In Attachment I to this instant *Petition*, the Company complied and provided the required analysis. Xcel's analysis demonstrated that the cumulative cost savings of $1.4 million has been realized through 2017 by using contractor services over in-house costs for specialized

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[19] *Id.*, Subds. 2 and 4.
[20] See Xcel's compliance matrix provided in initial filing, Attachment A, p. 2.

equipment ownership and increased workforce needs. Xcel expects this 10-year project to be completed in 2019 and expects continued year-over-year comparable cost savings. The Department reviewed and concluded that the Company's analysis is reasonable. The Department appreciates Xcel's upfront provision of the information.

B. PROJECT ELIGIBILITY

Xcel's *Petition* includes projects previously approved for recovery in earlier GUIC filings and does not propose new projects. Further, Xcel has fully completed its East Metro Pipeline Replacement Project. 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.[21] However, as discussed in Section III.D.5 below, the Department has identified cost-related concerns regarding Xcel's proposal.

C. PROJECTED GUIC ACTIVITY AND RIDER DURATION

Regarding the GUIC Rider duration, the Commission stated in its *Order* in Docket 14-336 that it would:

> …have an opportunity to review the GUIC rider on an annual basis and to make any needed adjustments or require the Company to file a rate case, if that is appropriate. For this reason, the Commission finds it unnecessary to set a definite end date for the GUIC rider.

Due to this conclusion, the Department makes it a habit each year to review whether or not the GUIC Rider should have an end date prior to its statutory end date of 2023, and also whether the Company should come in for a rate case. To this end, the Department reviewed the Company's projected GUIC expenditures and revenue requirements, as well as its recent effective return on rate base.

In its *Petition Supplement*, Xcel provided its updated plan for TIMP and DIMP project expenditures. The total TIMP and DIMP projected expenditures from 2019 through 2022 are shown in Table 5 below.

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[21] Sometimes projects need to be reevaluated when new information arises. For example, the Crossover Pipeline Project was originally assessed as a high-risk pipeline, thus needed remediation to address safety risks; therefore, the Crossover Project costs were included in the GUIC Rider. However, Xcel recently discovered additional information, and once the overlooked pressure test documentation was taken into account, the project was re-scored and assessed as a low-risk item. Xcel will remove this projects' costs from the GUIC Rider in its Reply Comments. DOC IR No. 55 included as DOC Attachment 3.

Table 5
Xcel's Projected 2019-2022 TIMP and DIMP Expenditures
($ Millions)

	2019		2020		2021		2022	
	Capital[22]	**O&M**[23]	**Capital**	**O&M**	**Capital**	**O&M**	**Capital**	**O&M**
TIMP	$26.82	$2.55	$20.47	$1.49	$30.94	$1.48	$30.79	$1.48
DIMP	$34.14	$2.78	$26.85	$0.58	$17.27	$0.58	$17.27	$0.58
Total	$60.96	$5.33	$47.32	$2.07	$48.21	$2.06	$48.05	$2.06

The above table indicates that the Company is planning to continue to use the GUIC Rider.

The Department also reviewed Xcel's Annual Jurisdictional Report for 2017.[24] The weather-normalized overall return on rate base for 2017 was 7.01 percent, and is projected to be 6.75 percent in 2018. While neither of these figures are audited by regulators, both are less than the rate of return authorized in the Company's last gas rate case (8.28 percent). While the Department's proposed 2018 GUIC rate of return (7.02 percent) is lower than the ROR approved in its last gas rate case, it is effectively equal to the Company's 2017 actual ROR, and higher than its projected ROR for 2018.

Since the Department's proposed ROR is bracketed by Xcel's allowed ROR on base rates and effective ROR, it does not appear that enough value would be captured by ending the GUIC or by requiring the Company coming in for a rate case. At this time, the Department does not recommend that the Commission end the GUIC Rider or recommend that a general rate case be filed. However, as noted in the *Issues* section next, the Department has identified issues with Xcel's recovery proposals that should be addressed.

The Department intends to continue to monitor Xcel's cost recovery proposals and rate of return on rate base proposals in future filings.

D. ISSUES IDENTIFIED

The Department conducted its review of the Company's *Petition* and raises several issues with Xcel's proposal. These issues are discussed separately below.

[22] *Petition Supplement*, Attachment E.
[23] *Petition Supplement*, Attachment J. TIMP figures are not total expenditures, but post-MN Allocated expenditures.
[24] Docket 18-04.

1. Concerns with Certain Revenue Requirement Components

a. Rate Base[25]

Xcel Gas' GUIC Rider includes a rate base amount upon which a return on investment is calculated for GUIC rider recovery purposes. The GUIC net rate base amount comprises three components: plant-in-service, accumulated depreciation, and accumulated deferred taxes. Per Section 216B.1635, the GUIC Rider should include only the incremental costs associated with GUIC projects. From its review of the Company's *Petition*, the Department concluded that the Company's 2018 GUIC rate base is overstated because it is not appropriately adjusted to reflect only the incremental change in plant-related costs for rate setting. The issue was brought to light from Xcel's adjustment to the accumulated depreciation element of the GUIC rate base components for removal costs, as this adjustment as currently executed is an incomplete quantification of incremental changes, favoring shareholders to the detriment of ratepayers.

i. Background of Accumulated Depreciation Reserve

Briefly, accumulated depreciation generally acts to reduce rate base. The accumulated depreciation balance in its most basic form represents the amount of an asset investment that has been "used up" for ratemaking purposes. However, in more complex applications, the accumulated depreciation balance also reflects, in part, future projected expenditures related to the disposal of an asset (or removal costs) on its retirement. The assets that are known to cause the owner a future liability or cost that exceeds any remaining value have "negative net salvage values."

Natural gas pipelines are assets that have a negative net salvage value; thus on retirement, additional expenditures are expected to be incurred to remove the asset from service. To account for the additional expenditures expected at the asset's end-of-life, pipeline asset depreciation factors are designed to build in estimated removal costs; as a result, the annual calculated depreciation expense not only reflects a portion of the original investment cost, but also the estimated future removal costs, amounts that too are accrued over the useful life of the asset. The summed total of depreciation expense that has accrued over time is reflected in the accumulated depreciation reserve account. Therefore the accumulated depreciation reserve includes recovery-to-date of the original cost of the pipeline, or the upfront investment, as well as the expected future cost expenditures to remove the pipeline from service.

As a basic example, a $1,000 asset (plant item) is placed in service in 2006, with an estimated useful life of 10 years. This asset has an estimated negative net salvage value equivalent to 22 percent of original cost, or ($220). After the 10-year period, 100% of the original cost would be depreciated as well as an additional 22% of the original cost to account for the expected future

[25] *Petition,* Attachments F and G.

expenditures to remove/decommission the asset. Therefore, the calculated depreciation factor, applied annually, would be 12.2%. In 2010, after four in-service years, the depreciation reserve would have accumulated a $488 balance; thus the net rate base would be $522 (that is $1,000 original cost reduced by $488).[26] Essentially, $400 of the $488 accumulated depreciation balance represents recovery of the asset's original cost and the remaining $88 is recovery of the future expected removal costs, as summarized in the following Example 1:

ii. Proposed Accumulated Depreciation Reserve Adjustment

Several of the GUIC projects replace (or retire) existing natural gas pipeline assets. Xcel explained that when GUIC pipeline projects are installed, the Company accounts for the existing pipeline removal costs activity in the GUIC Rider rate base and does so by adjusting the

Example 1:			Asset A.1	
			Annual	After 4 years
Useful Life (Yrs)		10		
Salvage Value		-22%		
Original Cost		$ 1,000		
Depreciation Expense				
	Original Cost		$ 100	
	Negative Salvage Cost		$ 22	
	Total		$ 122	
Accumulated Depr. Reserve				$ 488
Net Book Value (Rate Base)				$ 512

accumulated depreciation reserve balance.[27] The effect of the "removal-costs adjustment" reduces the accumulated depreciation reserve balance and, therefore, increases the GUIC rider rate base (and revenue requirement). However, the Department observed that Xcel's approach of including removal-costs for the old plant by adjusting the accumulated depreciation reserve alone fails to achieve the required objective to arrive at the incremental change in costs for purposes of GUIC rate recovery. To determine incremental costs, the Department points out that the relevant approach is to evaluate holistically the extent to which the now-replaced asset contributed to base rates.

[26] For simplicity sake, the example's stated "rate base" omits the effect of averaging the beginning/end of period plant balances and reserves.
[27] DOC IR No. 14.D and 41.A included as DOC Attachment 4.

In DOC IR No. 8, the Department asked where in the filing Xcel included adjustments to rate base for the old plant being removed from service; this information is needed to evaluate the extent to which the now-replaced asset is recovered in base rates so that only the cost differential of the new infrastructure is included in the GUIC rider rate base. In its response, the Company explained it is unable to identify the specific plant assets replaced due to use of the group accounting method.[28] Group accounting is often used to treat large quantity assets of like nature as a whole, rather than individual assets. The Company's response appeared to further reason that no adjustment to plant balance was needed because when pipeline plant is retired, it is removed from the Company's books at a net zero balance, and that assets being replaced have a net book value far lower than their initial value.

Though the response is informative on the *current value* assumed for the retired plant, it is not on point because it fails to show that Xcel's proposed GUIC rate base represents only the incremental change in costs compared to the amounts that continue to be charged to ratepayers in base rates for the portion of its system being replaced. Instead, the response demonstrates that Xcel did not represent the 2010 test year "snapshot" of the replaced assets' contribution to base rates to arrive at an incremental cost amount for rider recovery purposes.

Not all the pipelines being replaced by GUIC projects were fully depreciated at the time of Xcel's last gas rate case; this fact must be taken into account to determine the incremental costs for the GUIC Rider. Specifically, the Department noted that when Xcel's last gas rate case test year was established, some of the existing plant (recently replaced by GUIC projects) had positive years of life remaining, as shown in its response to DOC IR No. 8, Attachment A.[29] Because this response data indicates that some of the existing plant was not fully depreciated as of the 2010 test year, without regard to salvage value, the plant was part of the 2010 test year rate base; hence the rates charged to Xcel's ratepayers continue to include recovery of these facilities. Specifically, Xcel's current base rates include a return on the balance of plant that was not fully depreciated, along with all other associated costs.

Xcel's *Petition* included the removal (or salvage) costs of the old plant in the 2018 GUIC Rider by adjusting the accumulated depreciation, which effectively increases the proposed 2018 GUIC rate base; however, Xcel did not similarly adjust the GUIC rate base downward to account for any of the undepreciated portion of the old plant's original cost included in the 2010 test year. Xcel's proposal is unbalanced because it made partial adjustments in the rider rate base which benefitted its shareholders, without reflecting the remaining necessary adjustments that would benefit ratepayers.

[28] DOC IR No. 8 included as DOC Attachment 5.
[29] DOC IR No. 8 included as DOC Attachment 5.

As a result, Xcel's *Petition* overstates the incremental cost for the GUIC recovery rider. By only including removal costs of the existing plant in the GUIC rate base without also adjusting the proposed GUIC rate base by the 2010 test year remaining original cost of the existing plant replaced, Xcel's unbalanced proposal would overstate incremental costs. Overstated incremental costs lead to overstated rider revenue requirements; that is, Xcel would double recover certain costs, once in base rates and again in the rider. In this instance, without correction, Xcel would continue to charge ratepayers in base rates for the costs of now-retired/replaced pipeline assets that are no longer used and useful or in service due to the GUIC project, on top of charging ratepayers through the rider for the full cost of the placed-in-service, renewed pipeline-system assets.

The Department recommends that the Commission require Xcel to include only incremental rate base amounts in its GUIC Rider rate base. If Xcel Gas cannot reasonably determine the remaining original book value[30] of existing plant included in base rates that have since been replaced or retired due to GUIC projects, then at a minimum Xcel Gas should also not be allowed to adjust the GUIC rider's accumulated depreciation reserve by removal costs of the old plant.

b. Depreciation Expense

In the *Petition*, the Company included a recovery request for depreciation expense. The Company calculated depreciation expense by applying a depreciation rate[31] to the average monthly 2018 GUIC plant-in-service balance. Schedules with detailed calculations were provided by the Company in its response to DOC Information Requests included as DOC Attachment 6 to these comments.[32] The Department raises two concerns with the Company's proposed depreciation, (1) the expense amount recoverable through this rider, and (2) the depreciation factor used to calculate the GUIC projects' depreciation.

i. Depreciation Expense recoverable through the Rider

Per statute Section 216B.1635, Subdivisions 2 and 4, the GUIC Rider should include only the incremental amount of costs, one of which is depreciation expense. From its review of the *Petition*, as discussed above, the Department concluded that the Company's requested depreciation amount for the GUIC Rider revenue requirement is not the incremental expense amount. Rather, the Company has overstated the rider-recoverable depreciation expense.

In the 2018 GUIC *Petition*, the Company used an average GUIC plant-in-service balance and the latest-approved depreciation factors to calculate the depreciation amount requested to be recovered. The plant-in-service balance reflects the capitalized cost of the GUIC projects placed

[30] Excluding salvage accumulations.
[31] See *Petition*, Attachment K for inputs used by Xcel.
[32] DOC IR Nos. 44 and 45 included as DOC Attachment 6.

in service.[33,34] However, the resulting depreciation amount calculated on the GUIC average plant balance was not adjusted by the depreciation expense amounts currently being recovered in base rates that are relevant to the plant replaced (or retired) by the GUIC projects.

Xcel's base rates, established in its most recent gas rate case (Docket No. G002/GR-09-1153), included depreciation expense calculated on the original cost of the plant that was in place during the test year (2010). The depreciation amounts included in base rates were determined using the then-approved depreciation factors from Docket No. E,G002/D-07-1528.

Because Xcel Gas did not adjust the GUIC-projects' depreciation expense by the base-rates' depreciation amount tied to the plant replaced (or retired), the depreciation expense proposed for recovery in the rider is not incremental. As a result, the Department notes that Xcel Gas has overstated the depreciation expense included in its GUIC filings. The Department recommend that the Commission require the Company to recalculate the incremental depreciation expense amount by accounting for the depreciation expense amounts included in base rates relevant to the plant assets replaced by (or retired through) the GUIC projects included in this rider.

ii. Depreciation (Factor) Rate Used to calculate Depreciation Expense

In calculating depreciation expense for the GUIC projects, the Company used depreciation factors that were approved in its last depreciation filing (Docket No. E,G002/D-12-858). However, Xcel had a pending depreciation filing, Docket No. E,G002/D-17-581 (Docket 17-581) that has since been heard by the Commission on April 26, 2018, in which the Company proposed a change to its depreciation methodology, and ultimately, its depreciation factors. In its response to DOC IR 37.2, Xcel Gas estimated a $540,000 reduction in the 2018 GUIC revenue requirement if the depreciation changes proposed in Docket 17-581 were approved and applied to GUIC projects herein.[35] The Department recommends that the Company incorporate and apply the recent Commission-approved depreciation factors in Docket 17-581, when calculating GUIC-projects' depreciation in this *Petition*.

c. Property Taxes

Xcel Gas included property tax expense in its 2018 GUIC Rider revenue requirements. Per statute Section 216B.1635, Subdivisions 2 and 4, the GUIC Rider should include only the incremental amount of costs, one of which is property tax expense. From its review of the *Petition*, the Department concluded that the Company's requested property tax expense included in the 2018 GUIC Rider revenue requirement does not reflect the incremental expense amount. Rather, the Company's methodology overstates the rider-recoverable property tax expense.

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[33] *Petition*, Attachments F and G
[34] DOC IR No. 40 included as DOC Attachment 7.
[35] DOC IR No. 37 included as DOC Attachment 8.

Xcel Gas calculated the proposed property tax amount for the GUIC by multiplying the GUIC plant balance (original cost) by an estimated property tax rate of 1.7 percent.[36] Since property tax rates vary by jurisdiction where Xcel's gas pipeline assets are located, the Company derived the overall composite 1.7 percent rate by dividing the Company's total calendar year personal property tax paid by the total original cost of personal property at the start of the tax year. For instance, the Company divided the 2016 personal property tax assessment (which is later paid in 2017) by the original cost of gas utility personal property measured at the close of December 31, 2015.

While the Department does not object to the Company's approach to derive an approximate composite property tax rate, it is the Company's application of the 1.7 percent rate to an *unadjusted GUIC plant balance* that fails to reflect incremental costs. Rather, the differential between the cost of the GUIC project placed in service and the original cost of the plant replaced (or retired) by the GUIC project should first be determined; then, only the differential should be subject to the property tax rate in order to develop the incremental property tax expense arising from GUIC projects.

Xcel Gas' base rates already include property tax recovery imputed on the value of the plant that has since been replaced (or retired) by GUIC projects; for that reason there is a need to isolate only the differential between new and old plant original cost amounts. The GUIC Rider is to include only incremental costs associated with GUIC projects. Therefore, the Department recommends that the Commission require Xcel to recalculate the incremental property tax expense amount for all GUIC years by adjusting original cost of GUIC projects by the original cost of plant assets replaced by (or retired through) the GUIC projects in each year, prior to applying Xcel's calculated property tax rate. Any overstated revenue requirements should be credited back to ratepayers.

d. 2018 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."[37] In compliance with this statutory directive, the Commission set the authorized 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 used the same capital structure and authorized ROR on debt (taken from Xcel's 2013 electric rate case, Docket No. E002/GR-13-868), only updating the authorized ROR on common equity, from 10.09% in 2015, to 9.64% in 2016, and 9.04% in 2017.

[36] DOC IR No. 43 and Email on IR 43 included as DOC Attachment 9.
[37] Minn. Stat. § 216B.1635, Subd. 6.

For 2018, Xcel proposes to again maintain the capital structure and authorized ROR on debt used for past years, but update the authorized ROR on common equity to 10.00%, resulting in an overall authorized ROR of 7.52%.

The Department does not support Xcel's proposal and instead supports maintaining the authorized ROR at 7.02%, as approved in February, 2018. Maintaining the overall ROR would adopt the Commission's past policy of using the same capital structure and ROR on debt from previous years, a policy that has worked well and which Xcel supports. The only difference from prior years would be that this policy would be extended to the ROR on common equity, keeping the overall ROR unchanged. This slightly altered policy would make the ROR aspect of the GUIC Rider consistent with how the ROR is applied to general rates, in which the ROR is not updated year to year. Further, this approach would make the GUIC Rider more consistent with other rates and streamline regulatory review. As a result, given the information available at this time, the Department concludes that maintaining the overall ROR from year to year is in the public interest.

2. Prorated ADIT and Rate Effective Date

Xcel Gas proposed to implement its 2018 GUIC revenue requirement rate factors prior to the close of the 2018 calendar year. Because of Xcel's proposed rate implementation timing, the Company's 2018 GUIC revenue requirements are increased due to the impact of prorating the accumulated deferred income tax (ADIT) projections.

ADIT reflects tax costs charged to ratepayers in rates, but not yet paid by the utility to the income taxing authority. In utility ratemaking, ADIT balances reduce rate base upon which a rate of return is calculated because ratepayers funded this operating cost in advance.

Prorating ADIT is required by the Internal Revenue Service (IRS), as part of normalization requirements for ratemaking, when forecast test periods are used in setting rates and the rates are implemented prior to the end of the test period. The prorated ADIT methodology reduces the credit to rate base for ratemaking purposes than would otherwise occur by using averaging typically applied to other rate base components; thus the prorated ADIT method increases rates charged to ratepayers. See DOC Attachment 10 to these comments for more extensive explanation of the prorate ADIT method.

Although this rider is subject to true-ups, an IRS-issued private letter ruling (PLR) on the matter, to an undisclosed utility company, indicated the effect of using prorated ADIT cannot be undone within a rider true-up.[38] Because of the ongoing harm to ratepayers, and the fact that the IRS has provided an opportunity to avoid harm entirely by implementing the rate at least

[38] IRS PLR 201717008 released April 28, 2017, https://www.irs.gov/pub/irs-wd/201717008.pdf at page 14, ordering paragraph 4.

one day after the test period, the Department objects to implementing a rider rate in midst of the forecast test period.[39]

To reasonably resolve this issue, in recent orders the Commission has directed rider rates to be implemented no sooner than the first day after the test period, recognizing that a rider is an extraordinary cost recovery mechanism enabling costs to be recovered outside of a rate case.[40] The Department fully supports this approach as being consistent with IRS requirements and reasonable ratemaking principles. Therefore, the Department recommends that the Commission likewise direct that the implementation of the 2018 GUIC rate to occur no sooner than January 1, 2019.

3. Sales Forecast

In its 2017 GUIC Filing (Docket 16-891), the Company used a calendar month allocation adjustment with the goal of better matching sales to historical trends. In addition, Xcel Gas applied a Demand-Side Management (DSM) adjustment to account for the impacts of conservation on expected sales. The Department disagreed with this methodology and recommended that 2017 GUIC Class Factors be based on the Company's regression model results before monthly sales and DSM adjustments. In regards to the monthly sales adjustment, the Department stated that it was inappropriate because it adds an additional layer of complexity to the Company's sales methods; further, the Department was unable to fully replicate the monthly re-allocation method.[41]

[39] *Id*. For example, at 7-8 and ordering paragraph 3:

> [I]f rates go into effect after the end of the test period, the opportunity to flow through the benefits of future accelerated depreciation to current ratepayers is gone and so too is the need to apply the proration formula. In this situation, the only question that is important for the purpose of rate base exclusion is the amount in the deferred tax reserve, whether actual or estimated. Once the future period, the period over which accruals to the reserve were projected, is no longer future, the question of when the amounts in the reserve accrued is no longer relevant (at the time the new rate order takes effect, the projected increases have accrued, and the amounts to be excluded from rate base are no longer projected but historical, even though based on estimates).

[40] Commission Order issued February 8, 2018 in Docket No. G002/M-16-891 *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 True-up Report for 2016, Forecasted 2017 Revenue Requirement, and Revised Adjustment Factors.* Commission Order issued August 24, 2017 in Docket No. G002/M-17-174 *In the Matter of the Petition of Northern States Power Company for Approval of a Modification to its Natural Gas State Energy Policy (SEP) Tariff, 2017 SEP Rate Factor, and 2016 SEP Compliance Filing*

[41] The historical adjustment discussed here should not be confused with the billing cycle/calendar month adjustment that accounts for the fact that billing months do not necessarily align with calendar months. The Department considers that adjustment to be perfectly reasonable, and has no objections to using it.

In Reply Comments of that filing, the Company stated:

> Regarding the Department's first concern with re-allocating forecasted sales to match historical sales, the Company adjusts the monthly distribution of sales for the Residential, Commercial, and Small Interruptible rate classes. This adjustment is done to better align forecasted sales with historical actual sales on a calendar month basis in order to produce a monthly forecast that is more reflective of history than is the unadjusted forecast. The adjustments are done in a manner that ensures that the annual sales for a given calendar year remain unchanged; *i.e.*, the annual adjusted sales equal the annual unadjusted sales. Therefore, the Company is not changing the overall annual sales forecast. [Footnote: Furthermore, the additional layer of complexity claimed by the Department is minimal; sales are simply being moved between months within a year to better reflect historical patterns of sales, with annual totals not being changed.][42]
>
> We note that while the monthly adjustments are constrained so that annual sales do not change, when a different twelve month time period is considered, the adjustments may have a positive or a negative impact on sales. [Footnote: For example, for the twelve-month period of April 2017 to March 2018, the monthly adjustment process results in adjusted Residential sales being 0.3 percent lower than unadjusted sales, while adjusted Commercial and Small Interruptible sales each are 0.2 percent higher than unadjusted sales]. These are small impacts and will have a minimal effect on the calculated rate, whether it is a slightly higher rate or a slightly lower rate. Because the Company believes that it is appropriate to produce an accurate monthly forecast, we disagree with the Department's recommendation to eliminate these adjustments.[43]

At the Department's request, the Company also provided a forecast that did not include either the historical adjustment or the DSM adjustment.[44] In the Commission's 2017 GUIC Order, the Commission directed the Xcel "to establish rates based on unadjusted sales provided in Attachment F of Xcel's Reply Comments." Xcel filed compliance on February 20, 2018, and the Department filed a compliance verification letter on April 13, 2018.

[42] Docket No. G002/M-16-891, Xcel Reply Comments submitted March 13, 2017, page 10.
[43] Docket No. G002/M-16-891, Xcel Reply Comments submitted March 13, 2017, page 10.
[44] Docket No. G002/M-16-891, Xcel Reply Comments submitted March 13, 2017, Attachment F.

In the instant docket, the Department requested spreadsheets of the Company's forecast in DOC IR No. 29. The Department noted that the forecast provided by Xcel did not include the DSM adjustment, consistent with the Commission's 2017 GUIC Order, but *did* include the historical adjustment.

This inclusion of the historical adjustment is not in line with the Commission's 2017 GUIC Order. The Department notes that the Commission's Order Point concerning the forecast technically only applied to the 2017 GUIC Rider, and not directly to the 2018 GUIC Factor. However, the Department observes that the Company updated other components of this year's filing to comply with the 2017 GUIC Order. Therefore, the Department is unclear as to why this particular component of the 2017 GUIC Order was not implemented in the Company's *Petition Supplement*.

Additionally, the Department noted that the Company's forecast produced lower sales than the actual sales reported in the Company's Gas Jurisdictional Annual Reports (GJAR). In the current GUIC proposal, the Company projects 2018 sales of 89,314,493 dekatherms (Dth) and 2019 sales of 91,556,339 Dth. However, in Xcel's GJAR,[45] the Company reports 2016 actual sales of 97,104,355 Dth and 2017 actual sales of 99,469,703 Dth.[46]

The Department is unclear as to why actual sales reported in the GJAR are so much greater than the forecasted sales projected in the instant docket. The Department notes that both sets of data are weather-normalized, but posits that the two different data sources might be weather-normalized in different ways. However, it currently appears that the Company may be under-estimating forecasted sales.

In Reply Comments, the Department asks that the Company provide an updated forecast, without the historical monthly adjustment. Further, the Department asks that the Company clarify why forecasted sales for 2018 and 2019 are so much lower than actual sales reported in the GJAR for 2016 and 2017.

4. NSP-MN GUIC Project Cost Allocation Between Minnesota and North Dakota

Xcel Gas provides natural gas service to both Minnesota and North Dakota. While reviewing Attachment J to the *Petition*, the Department noted that Xcel Gas split some GUIC natural gas transmission-related O&M costs between the two states.[47] The Department also noted that in Xcel Gas' first GUIC petition, specifically Attachment I to Docket 14-336, the East Metro Pipeline

[45] Docket Nos. E,G999/PR-17-4 and E,G999/PR-18-4.
[46] The 2010 forecasted sales approved in the Company's last rate case were 85,785,149 Dth.
[47] In Xcel Gas' Attachment I to its Docket 14-336, the East Metro Pipeline replacement O&M costs were split between Minnesota and North Dakota. The East Metro Pipeline was a transmission line prior to replacement and is now classified as a distribution pipeline.

O&M costs were split between Minnesota and North Dakota. The East Metro Pipeline was a natural gas transmission line prior to replacement and is now classified as a distribution pipeline. Xcel's subsequent GUIC filings have not shown any further sharing of East Metro Pipeline costs between Minnesota and North Dakota. It is also the Department's understanding that there are ongoing GUIC projects being undertaken or planned by the Company that effectively have or will change the classification of certain pipeline system assets from transmission to distribution upon completion. The Company's filing does not discuss GUIC project cost allocation between Minnesota and North Dakota.

Therefore, the Department requests that Xcel Gas, in its Reply Comments:

- identify all completed and proposed GUIC projects that change the classification of the gas pipeline/plant system (i.e., from transmission-to-distribution or vice versa),
- explain the characteristics that caused the reclassification,
- detail the cost allocation treatment of that gas system infrastructure and its associated O&M costs between the two states before and after such classification change, and
- identify all Xcel Gas system integrity management projects undertaken or planned in North Dakota that affect the cost allocation treatment of that gas system infrastructure and/or associated O&M between North Dakota and Minnesota.

5. Project Costs Proposed For Inclusion in GUIC Recovery Rider

The Department issued several information requests to evaluate the various TIMP and DIMP projects and their costs that Xcel proposed to recover through the rider. The Department has concerns with the following items, as discussed below:

- Data Gaps – Insufficient Documentation Leading to Costs
- TIMP – Island Line South Project
- DIMP – Langdon Line Project
- DIMP – Lexington to Snelling Project
- DIMP/TIMP – Expenditures on Replacement of Low-Risk Infrastructure

a. DATA GAPS – Insufficient Documentation Leading to Costs

Xcel indicated that 21 percent of its transmission pipeline (or 15.6 miles) cannot meet the maximum allowable operating pressure (MAOP) validation as required by the federal law (49 CFR 192.619) due to insufficient records. According to the guidance provided by the PHMSA's issued advisory bulletin, records must be "TVC", 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).[48]

To remediate the insufficient records to support MAOP validation, Xcel stated it must either replace the pipeline, or perform pressure tests; under either option, the total costs to do so will amount to millions of dollars.[49] For instance, two of Xcel's TIMP-based projects undertaken to satisfy MAOP, the *East County Line* (South St. Paul) and *County Road B line* (North St. Paul) are multi-year pipeline replacements projects[50] that have estimated costs of $5.3 million and $36 million, respectively.[51]

Xcel has not demonstrated to the Department that the necessary information on the pipeline characteristics and/or testing needed to validate MAOP was not available or possibly known at the time, or since, the pipeline was installed; this lack of demonstration leads the Department to question whether Xcel had failed to properly acquire, secure, or record information about its pipeline system. Although Xcel argues that some of the pipeline was installed prior to the existence of pipeline safety regulation established in 1970, the Department has not been persuaded by Xcel that being able to validate maximum operating pressure is an extraordinary requirement of a pipeline system operator.[52] Nor has Xcel made an overarching claim that this MAOP-validation documentation is lacking for all of its pipeline, to which the regulation applies, installed prior to the passage of certain regulations.

When asked to quantify the amount of its distribution system subject to federal MAOP regulations[53] that lacks record data to support MAOP, Xcel stated 53 percent of its Intermediate Pressure (IP) pipeline in the Metro Area lacks necessary documentation to satisfy MAOP requirements.[54] This amount equates to 40.5 miles of Metro Area natural gas pipeline.[55] Xcel stated that it has yet to evaluate the additional 207 miles of intermediate pressure pipelines in Greater Minnesota. It is not clear in the record whether those additional 207 miles are subject to federal MAOP regulations[56] as well; therefore, the Department requests Xcel to clarify in its Reply Comments: 1) the extent to which the additional 207 miles of intermediate pressure pipelines are subject to MAOP regulations and 2) any updates or other information on these lines that may be helpful.

[48] See attached PHMSA Advisory Bulletin ADB-2012-06 included as DOC Attachment 11.
[49] DOC IR No. 35.C included as DOC Attachment 12.
[50] *Petition,* Attachment C, pp. 11-13.
[51] *Petition,* Attachment C1(e).
[52] DOC IR No. 24 included as DOC Attachment 13.
[53] 49 CFR 192.619
[54] DOC IR No. 35.C included as DOC Attachment 12.
[55] DOC IR No. 59 included as DOC Attachment 14.
[56] 49 CFR 192.619

Xcel stated that the remedies available to resolve the absence of data is to either conduct pressure tests (at a cost of $150,000 to $2 million per mile), or replace the pipeline (at a cost of $3 million to $8 million per mile). When applying these cost estimates to the Metro Area's 40.5 miles of intermediate pressure distribution pipelines lacking MAOP documentation, the range of Xcel's estimated costs equates to a $6 million to $324 million cost-range problem for the Metro Area lines alone. The newest pipeline without the necessary TVC documentation was installed in 1982, many years after the 1970 pipeline safety regulation was in effect.

The Department also noted that PHMSA's advisory bulletin states:

> PHMSA is supportive of the use of alternative technologies to verify pipe characteristics. Owners and operators seeking to use alternative or nontraditional technologies in the determination of MAOP or MOP, or to meet other regulatory requirements, should first discuss the proposed approach with the appropriate state or Federal regulatory agencies to determine its acceptability under regulatory requirements.[57]

The Department requests that Xcel, in Reply Comments, discuss whether or not it sought use of alternative technologies to determine MAOP in order to meet regulatory requirements and, if so, the results or status of efforts; and to discuss the economic analysis of doing so in lieu of pipeline replacements.

The operating system's data gaps are very concerning and problematic, especially since data records were and continue to be within the control of Xcel Gas' management. Therefore, the Department recommends that the Commission consider either: 1) limiting the "return on" the capital costs incurred to remediate the system's MAOP data gaps to Xcel's long-term debt costs or 2) not allowing extraordinary rider ratemaking treatment for projects where Xcel lacks sufficient data.

b. TIMP – Island Line South Project

The Island Line South project is a TIMP-based project described as 1.9 miles of 20-inch natural gas pipeline along the Mississippi River that Xcel is assessing to determine work that is needed. The Company proposes to include costs in the 2018 GUIC Rider attributed to Island Line expenditures; however, Xcel hasn't fully explained the reasoning and necessity for incurring certain costs.

[57] See attached PHMSA Advisory Bulletin ADB-2012-06 included as DOC Attachment 11.

First, the *Petition* indicates that this 1952 pipeline is slated for replacement, and small segments have recently been replaced; however, expenditures to construct ILI access, in addition to planned expenditures to conduct ILI assessment, are requested for rider recovery. Xcel Gas did not provide adequate justification of the reasonableness and necessity to incur and charge ratepayers for the costs of ILI improvement and ILI assessment costs, in light of Xcel's planned replacement of this pipeline, has not been satisfactorily explained to the Department.[58] Therefore, the Department recommends that, at a minimum, that Xcel be directed to exclude the $0.6 million estimated costs of the ILI assessments to be performed on the Island Line South pipeline designated to be replaced.

Second, for this Island Line project, the Company attributed its estimate-to-actual variance to excessive water pumping costs, which too, had not yet been clearly supported by the Company's filing. The Company initially estimated project cost at $1.7 million, but the actual costs were $3.2 million, leaving a $1.5 million variance (an 88% cost overrun).[59] The Department notes that, even though natural gas utilities are required to provide information about actual costs compared to forecasted costs, no utility is entitled to recover cost overruns in a rider, particularly if the utility fails to demonstrate that it would be reasonable to recover such costs through a rider.

Xcel did not provide sufficient information in its initial filing to demonstrate the reasonableness of charging costs that were nearly double the amount that Xcel originally estimated. Further, although the Department obtained and reviewed correspondence and 2016 invoices for this project (DOC IR No. 56), this information did not substantiate the $1.5 million variance. Therefore, the Department concludes that Xcel did not demonstrate the reasonableness of including these cost overruns in the GUIC rider, thus should be removed from GUIC Rider recovery.

c. DIMP – Langdon Line Project

The Langdon Line project is one of Xcel's proposed distribution pipeline replacement projects.[60] The existing Langdon Line assessment was scored as a high risk line by Xcel due to the threat severity combined with its location in a high consequence area.[61] Design and construction is expected to be completed in 2018 and 2019. The project entails replacing six miles of varied diameter pipe (12-inch, 8-inch and 6-inch) installed in 1958 with a single diameter line that could support use of in-line inspection technology. Xcel proposed to use 12-inch pipe for this project, estimated to cost $12.5 million; after removing internal costs, the amount would be $11.8 million that Xcel would include in the 2018 GUIC Rider.[62]

[58] DOC IR No. 17 and Email from Xcel included as DOC Attachment 15.
[59] Petition, Attachment T, Footnote 1.
[60] *Petition,* Attachment D, p. 9.
[61] *Petition,* Attachment D2(a), p. 6 and DOC IR No. 55.
[62] DOC IR No. 33 included as DOC Attachment 16.

The diameter of pipe used in pipeline projects influences the overall project costs. In its discovery responses to DOC IR No. 31, the Company estimated that if it used matching, varied pipe diameters when replacing the Langdon Line, it would reduce capital cost of this project by $4.4 million. Alternatively, when asked about the service adequacy and cost differential should a single diameter 8-inch pipe be used for this project, rather than the proposed 12-inch pipe, the Company responded that an 8-inch pipe would provide adequate service and reduce the project's installation cost by $3.6 million.[63] To defend its proposal to use a 12-inch diameter pipe, Xcel stated, "This will allow for ILI to be used on the entire line, which helps ensure gas system safety and reliability." However, the Department points out that the Company's response did not say that an in-line inspection tool could not be used on an 8-inch diameter pipe.[64]

Because using an 8-inch pipe for the Langdon Line would adequately serve Xcel's customers, and likely be ILI compatible, it appears to the Department that Xcel's proposal to replace the current pipeline (which consists of 6-, 8- and 12-inch pipe) with a 12-inch pipe for the entire line is not prudent, and appears to constitute a betterment. Statute section 216B.1635 Subd. 5 states:

> …the commission may approve the annual GUIC rate adjustments provided that, after notice and comment, the costs included for recovery through the rate schedule are prudently incurred and achieve gas facility improvements at the lowest reasonable and prudent cost to ratepayers.

In addition, Statute section 216B.1635 Subd. 1 (b)(3) states that GUIC means costs incurred in gas utility projects that:

> …do not constitute a betterment, unless the betterment is based on requirements by a political subdivision or a federal or state agency, as evidenced by specific documentation, an order, or other similar requirement from the government entity requiring the replacement or modification of infrastructure.

It is the Department's understanding that use of in-line inspection technology on distribution pipelines is not mandated by any government body or regulation. Further, the Company did not provide support that an in-line inspection tool could never be used on an 8-inch diameter pipe currently, or sometime in the future. According to an article issued by a pipeline engineering firm,

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[63] DOC IR No. 31 included as DOC Attachment 17.

[64] In DOC IR No. 32 response regarding a different pipeline replacement project (H005 – Lexington to Snelling), the Company indicates use of 8-inch pipe for that project will allow for use of ILI technology. DOC IR No. 32 is included as Attachment R to these comments.

> The continued sophistication and miniaturization of the electronic systems used in the intelligent pigs has allowed the development of smaller pigs that can be used in small-diameter pipelines.[65]

Also, the abstract of a recent article *Advances in the Inspection of Unpiggable Pipelines* published by the University of Leeds, School of Mechanical Engineering states in part:

> The field of in-pipe robotics covers a vast and varied number of approaches to the inspection of pipelines with robots specialising in pipes ranging anywhere from 10 mm to 1200 mm in diameter.[66]

The Department agrees that having little or no pipe diameter variation on this segment is preferable to facilitate potential use of in-line inspection tools; however, the recoverable amount for the Langdon Line project through the 2018 GUIC Rider should be limited to a project cost assuming an 8-inch pipe, rather than the 12-inch, to achieve gas facility improvements at the lowest reasonable and prudent costs to ratepayers and to adjust out system uprate costs. Therefore, when the Langdon Line project is placed in service, the Department recommends that the Commission require that the project amount includable in the 2018 GUIC Rider rate base be reduced by the project cost differential between use of a 12-inch and an 8-inch pipe, estimated to be approximately $3.6 million. This recommendation does not preclude Xcel from requesting full project cost recovery in its next rate case.

d. DIMP – Lexington to Snelling Project

The H005 – Lexington to Snelling (H005) project is a 3-mile high-pressure distribution pipeline replacement estimated to cost $4.9 million, of which $4.6 million is proposed to be recoverable once internal costs are removed.[67,68] Xcel stated that the existing 1964 pipeline, which scored as high risk by Xcel's assessment, has a history of leak repairs, most notably caused by material failure, mechanical defects, third party damage and corrosion. Xcel plans for the new pipeline to be constructed in a manner to allow for use of in-line inspection tools.

In its undertaking of this particular pipe replacement, Xcel proposes to relocate approximately 20 services currently connected to this line; to do so, it would extend a nearby pipeline system to facilitate transfer of customer services to this alternate line. In response to DOC IR No. 32.B, Xcel explained that removing services from the H005 line would allow in-line inspection to be

[65] *Pig Trap/ Pig Launcher/Intelligent Pig* issued February 17, 2016 by Subsea Pipeline Engineering. https://sabrinapurba.wordpress.com/2016/02/17/pig-trap-pig-launcherintelligent-pig/ accessed April 21, 2018.
[66] *Advances in the Inspection of Unpiggable Pipelines* , published November 29, 2017, written by George H. Mills, Andrew E. Jackson and Robert C. Richardson, University of Leeds, School of Mechanical Engineering; http://www.mdpi.com/2218-6581/6/4/36/htm accessed April 21, 2018.
[67] *Petition*, Attachment D, pp. 10-11.
[68] DOC IR No. 33 included as DOC Attachment 16.

performed without disrupting service to large volume commercial customers.[69] Through discovery, Xcel responded that no regulatory directive prescribed that services not be connected to high pressure distribution pipelines; rather, the Company opted not to reconnect existing services back to the new H005 pipeline. Xcel estimated that $420,000 of this project's cost is attributed to its proposed extension of other facilities in order to relocate services to a different part of its pipeline operating system.

Minn. Stat. § 216B.1635 Subd. 1 (b)(c)(2) states that "Gas utility projects" means:

> …replacement or modification of existing natural gas facilities, including surveys, assessments, reassessment, and other work necessary to determine the need for replacement or modification of existing infrastructure that is required by a federal or state agency.

The Department concludes that the costs attributed to extend another part of Xcel's pipeline, to enable Xcel, at its option, to transfer services to another section of its system, do not satisfy some authority's requirement and do not fit under the definitions of the statute. Therefore, the Department recommends that $420,000 of the H005 project costs be excluded from GUIC recovery rider. Again, this recommendation does not preclude Xcel from requesting full project cost recovery in its next gas rate case.

e. DIMP/TIMP – Expenditures on Replacement of Low-Risk Infrastructure

In the Department's investigation, Xcel disclosed in response to DOC IR No. 35 that it included in the 2018 GUIC Rider costs incurred for low-risk distribution infrastructure replacement undertaken in conjunction with work activity for high risk remediation projects.[70] Xcel explained that it opted to do this additional work to minimize disruption to the local community. The low-risk DIMP capital expenditures identified totaled approximately $85,000. Because these expenditures on low-risk infrastructure replacement were elective, not supported by civic/public work requirements, nor required by government regulations, the Department recommends that Xcel remove these costs from the GUIC Rider.

In addition, Xcel later identified that the TIMP-based Crossover Pipeline Project previously included in the GUIC Rider, was incorrectly scored as high risk, when in fact should have been scored as a low-risk project, once previously overlooked pressure test records were taken into account. Project design occurred in 2017 and Xcel planned construction for 2018.[71] Xcel had included incurred Crossover Pipeline Project costs in the prior 2017 GUIC Rider, and has now committed to removing that project's costs from its revenue requirement and reversing prior

[69] DOC IR No. 32 included as DOC Attachment 18.
[70] DOC IR No. 35 included as DOC Attachment 12.
[71] *Petition*, Attachment C, p. 14.

rider recovery, in its forthcoming Reply Comments' revised schedules.[72] The Department appreciates Xcel's additional review efforts and the corrective action to remove this low-risk project and its costs from the GUIC Rider.

6. Review of Contracts, Work Orders, and Invoices

In Docket 16-891 (2017 GUIC), the Department expressed concerns regarding the contracts, invoices, and work orders related to software costs for Xcel's Pipeline Data Project (PDP). Initially, the Department noted that Xcel executed a contract for a project that included all of Xcel's utility affiliates, but failed to provide evidence that assigning these costs solely to Minnesota ratepayers was reasonable. In response to this concern, the Company stated that all work was done in Minnesota, providing a new Minnesota contract, as well as invoices and a map related to the PDP work. However, the Department found that some work orders contained different project numbers than either the original Minnesota contract or the newly provided Minnesota contract. The Department further found that Xcel provided work orders with invoice numbers that corresponded to its contract with Xcel's Colorado utility affiliate (the Public Service Corporation of Colorado, or PSCo). The Department also noted that some of the work orders included costs that were associated with projects that were not the PDP.

As a result of these discrepancies, the Department recommended that the Commission reject the Company's proposed level of DIMP software costs. Instead, the Department suggested that software costs be allocated to Minnesota ratepayers. The Commission supported the Department's recommendation.

In the instant docket, the Department conducted a three-step jurisdictional inspection of Xcel's contracts, work orders, and invoices. The first step was reviewing the contracts themselves to determine which parties were included in the contracts. The second step involved reviewing the Company's contract-specific cost data provided to the Department. The third step involved auditing invoices and work orders from the Company's data set.

The Department submitted three IRs asking for details on the Company's data, work orders, and invoices: IR 49, IR 62, and IR 63. Both Public and Trade Secret versions of the Company's responses are provided in Attachment 19 to these Comments. Results and information pertaining to this jurisdictional review are provided in Public and Trade Secret versions in Attachment 20 to these Comments.

Finally, the Department notes that this jurisdictional review did not cover all costs that the Company proposed to include in the GUIC, but only costs that could be traced back to a specific vendor or contract. The following table shows all of the Company's total incurred Capital and

[72] DOC IR No. 55 included as DOC Attachment 3. The 2018 revenue requirements of $100,094 will be removed, along with a credit for the 2017 revenue requirements of $4,140.

O&M costs (prior to the removal of non GUIC-eligible work) by whether these costs are included in the Department's review.

Table 6. Total 2017 O&M and Capital GUIC Costs to Xcel by Inclusion in the Department's Jurisdictional Review of Costs

	Included in Department's Jurisdictional Review (costs able to be traced back to specific contract)	Not included in Department's Jurisdictional Review (costs not able to be traced back to specific contract)	Total[73]
O&M	$4,327,128	$3,691,042	$8,018,170
Capital	$17,366,758	$8,276,882	$25,643,640
Total	$21,693,886	$11,967,924	$33,661,810

The Department is not concerned about the O&M costs not included in the Department's jurisdictional review, as these costs largely comprise the Company's pre-2015 amortized costs already approved for recovery.

However, the Department continues to have concerns about the capital costs that cannot be traced back to a contract, despite the Department's attempts to understand more about the nature of these costs. While not all of the non-contract work has been included in Xcel's GUIC, it is not clear how much has actually been removed from the Rider. Further, the Company has explained in discovery that these costs largely comprise allocated and overhead expenses, but did not provide sufficient evidence to demonstrate that these costs were in fact GUIC-eligible. Ultimately, the Department was unable to verify that these costs were actually specific to work performed in Minnesota, or even truly incremental to costs already included in base rates. Therefore, the Department concludes that the Company has not met its burden of proof in demonstrating that $8,276,882 in capital costs should be included in the GUIC Rider.

a. Contract Review

In step one of this process, the Department reviewed the [**TRADE SECRET DATA HAS BEEN EXCISED]** contracts provided to the Department in the Company's response to IR 49. However, the Department identified additional vendors in the Company's data set and asked about the additional vendors in IR 62. The Company provided additional contracts, bringing to total to [**TRADE SECRET DATA HAS BEEN EXCISED]** contracts. Further, in this process, the Company identified three non-contracted vendors who were used for one-time services.

The Department looked at the following in each contract:

[73] Total O&M and Capital Costs are based on Figures reported by Xcel in response to IR 49. Total costs are costs to the Company and do not reflect non GUIC-eligible costs that have been backed out.

1. Who were the parties to the contract?
2. What was the geographic scope of work in the contract?
3. Which states did pricing schedules in the contracts cover?

The Department found that in seven contracts, the parties were the vendor and "Northern States Power- Minnesota," which includes Minnesota and North Dakota. All other contracts were between a vendor and multiple Xcel affiliates. One contract was between a vendor and Xcel's Colorado affiliate. No contracts specifically were between a vendor and the Minnesota jurisdiction of NSP-MN. The Department's detailed findings are summarized in Attachment 20, Table 1, entitled "Contract Jurisdiction."

In response to IR 62, the Company clarified that it does not maintain separate contracts for different jurisdictions; rather, jurisdictions are tracked through work orders. However, without information as to the state(s) in which work was done, the Department concludes that, in this portion of the Department's jurisdictional review, Xcel did not meet its burden of proof to show that it would be reasonable to charge all of the costs solely to Minnesota ratepayers.

b. Data Review

In Step 2 of its jurisdictional review, the Department looked through the Company's full data set of all costs proposed for recovery that were affiliated with outside vendor contracts.

For this process, the Department first wanted to ensure that all outside vendor contract data could be traced back to the contracts provided via contract, master agreement, or work order number. In response to IR 62, the Company provided a data set and an explanation that allowed the Department to link the data to the contracts. While the Department found some discrepancies between the contracts and the data, these discrepancies were mitigated by other factors that allowed the Department to conclude that the data could appropriately be traced back to the contracts. The Department notes these discrepancies in Attachment 20 under "Data Jurisdiction."

Once the link between the contracts and data was established, the Department conducted a visual inspection of the charges affiliated with each vendor in the dataset provided to the Department in Attachment D from IR 62.

In looking at the description of each charge, the Department asked the following questions:

1. Does the description of the charge demonstrate that work was definitively performed in Minnesota?

2. Does the description of the charge demonstrate that the work was definitively *not* performed in Minnesota?

For example, the Department considered data points with the following descriptions to be work performed exclusively in Minnesota:

12320752-ST. PAUL-ETNA-BIRMINGHAM-WINCHELL BTN HOYT & ARLINGTON-2016	$417.07
12526379-INSTALL NEW MONTREAL LINE SOUTH	$4,054.75
12586221-FOREST LAKE- IMPERIAL AVE & 216TH - INSTALL 3265' OF 2" PE D	$2,639.45

Alternatively, the Department considered the data points with the following descriptions to be jurisdictionally unclear:

12440381-SEWER REPAIR - GUIC RELATED	$895
12487770-17 SEWER MITIGATION - DIMP/GUIC – CONTRACTOR	$ 3,275

For data that was jurisdictionally unclear from the description alone, the Department looked other data elements, besides the charge descriptions. For example, the above two data points were associated with a "WBS Name" that appeared to be Minnesota specific, as shown here:

12440381-SEWER REPAIR - GUIC RELATED	$895	MNGUIC – DMN Sewer Conflict Investigatio[n]
12487770-17 SEWER MITIGATION - DIMP/GUIC – CONTRACTOR	$ 3,275	MNGUIC – DMN Sewer Conflict Investigatio[n]

The Department considered this type of jurisdictional data to be less robust than the description data, as these data do not provide specific locations within MN. In order to demonstrate that all costs should be charged solely to Minnesota customers, Xcel would need to provide more specific geographical data. Therefore, the Department continued to consider this data jurisdictionally unclear, despite the fact that "MN" was part of the "WBS Name" data element. All charges identified by the Department to be jurisdictionally unclear were O&M charges, under contracts that contained both Minnesota and North Dakota (NSP-MN), totaling $2,994,264.

The results of step 2 in this jurisdictional review can be found in Attachment 20, Table 2, entitled, "Data Jurisdiction." In this table, the charges affiliated with each vendor are identified as either appearing to be MN-specific, unclear, or not applicable. The Department provides further detail for jurisdictionally unclear charges in Attachment 20, Table 3, entitled "Jurisdictionally Unclear Data," in which the specific unclear charges can be identified.

Additionally, in response to IR 62, the Company identified two vendors whose work was performed outside of Minnesota. The Company proposed to remove the work affiliated with these vendors in a final compliance filing, which the Department supports.

c. Work Order and Invoice Audit

In step 3 of its jurisdictional review, the Department requested from Xcel copies of specific work orders and invoices for both Capital and O&M spending.[74]

For Capital invoices, the Department requested work orders and invoices associated with 25 charges from the Company's dataset provided in IR 62, Attachment D. The Department requested:

1. The top 11 greatest capital charges in the dataset.
2. The top 5 greatest capital credits to vendors in the dataset.
3. 9 charges across different vendors, including no identified vendor, above $3,000.

For O&M Invoices, the Department requested work orders and invoices associated with 14 charges from the Company's data set provided in IR 49, Attachment A. The Department requested:

1. 6 of the top 20 greatest O&M charges in the dataset.
2. 2 of the top 25 greatest O&M credits to vendors in the dataset.
3. 2 charges associated with database management for a vendor with jurisdictionally unclear charges
4. 4 charges with no identified vendor, above $3,000.

In its audit of these invoices and work orders, the Department found that in the majority of documentation provided, with one exception, there was some kind of clear indication that the work was performed exclusively in Minnesota. The results are provided in Attachment 20, Tables 4 and 5, entitled "Capital Inv WO Jurisdiction" and "O&M Inv WO Jurisdiction," respectively.

[74] In IR 49, the Department initially requested all work orders and invoices associated with all parent projects. In response, the Company noted that this would take too much time. Instead, Xcel provided the Department with multiple data sets related 2017 GUIC expenditures and offered to provide specific work orders and invoices upon request.

The one exception was for invoices provided to the Company by **[TRADE SECRET DATA HAS BEEN EXCISED**] for database management and "managed services." This exception is notable because, based on the jurisdictional review of this vendor's contract, the Department was unable to conclude that work done by this vendor was Minnesota-specific. In the data review, work done by this vendor was jurisdictionally unclear. Furthermore, the nature of the work, which is computer-based rather than located in a physical location, is something that could easily span multiple jurisdictions. Finally, in last year's GUIC Rider in Docket 16-891, the Department had concerns regarding software costs, similar to these database-specific costs.

d. Conclusion of Jurisdictional Review

The Department found that it was only able to perform a jurisdictional review of costs that could be tied back to a specific contract or vendor. Therefore, the Department was unable to review $8,276,882 in capital charges. Furthermore, while some of these charges may have already been removed from the Company's final GUIC-eligible figures, they seem to have largely comprised overhead and allocated costs. Therefore, the Department concludes that the Company has not met its burden of proof in demonstrating that these costs were either definitely in Minnesota, or truly incremental to costs already included in base rates.

Based on the costs that were included in the jurisdictional review, the Department concludes that, while Xcel demonstrated that some of the costs were for work exclusive to Xcel's Minnesota jurisdiction, the Company's system was not able to demonstrate that all of the costs were for projects performed only in Minnesota. Most notably, the Department found that the data review portion of this process contained $2,994,264 of costs that were jurisdictionally unclear because they did not provide the same level of detail as other costs in the Company's system. These costs were largely due to vendors whose contacts were executed by NSP-MN (which includes both MN and ND), although some jurisdictionally unclear costs contained no vendor and no contract number.

Therefore, the Department recommends that the Commission:

- Direct the Company to remove from the GUIC Rider $8,276,882 in capital costs not already removed unless the Company can adequately demonstrate that these costs are Minnesota-specific and incremental to costs captured in base rates;
- Direct the Company to use a jurisdictional allocator for all costs identified in Attachment 20, Table 3, unless the Company can provide invoices and work orders related to all of these charges; and
- Direct the Company to remove the work that is not Minnesota-specific, as identified by the Company in response to IR 62.

E. GUIC RIDER SCHEDULES

While a single year's GUIC Rider is not inordinately complex on its own, the implementation of various GUIC Riders over the years has made Xcel's GUIC a somewhat complex rider. For example, rates approved in Docket 15-808 are called the "2016 GUIC." These rates were in place from September 2016 through February 2018. However, the 2016 GUIC Rider revenues were only applied to the 2016 GUIC revenue requirement for the first seven months of that period; in the remaining 11 months, the 2016 GUIC Rider revenues were applied to the 2017 GUIC revenue requirement. To further complicate matters, the 2016 GUIC revenue requirement was also recovered by the revenue generated from rates approved in Docket 14-336 (the 2015 GUIC) over the period of January 2016 to August 2016.

This above example demonstrates how confusing and complicated this rider has become during implementation and tracking. The revenue requirements, rates, and recoveries of the GUIC Rider do not necessarily correspond in consistent or intuitive ways. In the instant docket, an additional layer of complexity was introduced in Xcel's *Petition Supplement*, as the Company proposed to concurrently charge the 2017 GUIC Rider alongside the 2018 GUIC Rider for the months of August 2018 through February 2018.

The Department was concerned that information was getting lost in this various activity, since the Company's "Monthly Trackers" (found in Attachment O of the Company's *Petition Supplement*) are primarily dedicated to monthly revenue requirements, with only the annual total recovery shown. The rates and monthly recoveries (and sales forecast) are presented separately in Attachment Q of the *Petition Supplement*. Further, while the Monthly Trackers in Attachment O show years 2016-2022, the information in Attachment Q only covers a 13-month span. This presentation, with revenue requirements tracked separately from recoveries and rates, makes it difficult to understand when, by which rates, and how much of each revenue requirement was actually recovered or is projected to be recovered. It also makes it very difficult to understand the actual balance of the GUIC Rider tracker at any given point in time.

As a result, it is difficult for the Department to verify any claimed carryforward balances and thus to ensure that the rates Xcel proposes to charge to ratepayers are "just and reasonable" as required by Minn. Stat. §216B.03, particularly when that statute requires that "[a]ny doubt as to reasonableness should be resolved in favor of the consumer."

At a minimum, the Department would prefer that, if Xcel continues to file future filings, the Company present its GUIC Rider tracker in a way that synthesizes the information in Attachments O and Q in the *Petition Supplement*, showing revenue requirements, rates, and recoveries on the same page. This approach not only would provide parties and the Commission with a better understanding of the GUIC Rider, but it would also be consistent with the format of at least one other rider tracker (the CIP Rider). Therefore, the Department recommends that the Commission require Xcel, in any future GUIC Rider filings, to present historical and projected GUIC Rider revenue requirements, rates, and recoveries within a single tracker for each year.

F. TRUE-UP REPORT, RECOVERY PERIOD AND TRACKER BALANCE CARRYING CHARGE

1. True-Up Report

Because the 2017 GUIC Rider is currently ongoing through February 2019, there is no true-up report at this time.

2. Recovery Period

Xcel requested to calculate the final rate adjustment factors to recover the 2018 GUIC Rider revenue requirements over an 8-month period, from August 1, 2018 through March 31, 2019. The Department presumes that Xcel proposed an 8-month recovery period in order to institute a recovery period that ends March 31, the recovery period term the Commission approved in Docket 15-808.[75] The Department does not support this proposal because of the Prorated ADIT issue discussed earlier (in Section III.D.2); rather the Department recommends that the approved rate become effective no soon than January 1, 2019. Consistent with IRS regulations, the Commission-approved resolution to the prorated ADIT issue in riders is to set recovery periods post test period; this approach has developed since the Commission's decision in Docket 15-808. Xcel's current 2017 GUIC Rider approved by the Commission was designed to collect the outstanding revenue requirement amount at the time of its implementation ($14.6 million), over a 12-month period, post test year.[76] Therefore, consistent with the Commission's decision in Xcel's most recent GUIC petition, the Department recommends a 12-month recovery period, effective no sooner than January 1, 2019.

The Department is aware that a January 2019 implementation would cause the 2017 GUIC recovery and the 2018 GUIC recovery rates to overlap for two months (January 2019 – February 2019). However, the 2018 GUIC Rider designed to collect revenue requirements over a 12-month period, as compared to an 8-month timeframe proposed by Xcel, would reduce the severity of bill impact from such an overlap. The following table shows illustrative Class Factors if 2018 GUIC Rider began in January 2019 and were collected over a 12-month period.

[75] Commission Order issued August 18, 2016 in Docket G002/M-15-808.
[76] See Xcel's Compliance filed on February 20, 2018 in Docket G002/M-16-891.

Table 7. Xcel Proposed Class Factors for 8-month timeline versus Department calculated rates for 12-month timeline.[77]

Rate Group	Xcel Proposed Class Factors, 8-month timeline (Aug 1, 2018-February 28, 2019)	Department Illustrative Class Factors, 12-Month timeline (Jan 1, 2019-Dec 31, 2019)
Residential	0.053784	0.045699
Commercial Firm	0.030490	0.025679
Commercial Demand Billed	0.025143	0.01894
Interruptible	0.018265	0.014159
Transportation	0.006870	0.003968

3. Tracker Balance Carrying Charge

In its initial filing of this docket, Xcel proposed that the then-pending 2017 GUIC Rider be stepped up for a limited time period (January 2018 – March 2018) to mitigate the under collected tracker balance; alternatively, Xcel requested implementation of a carrying charge, applied to the GUIC Rider carryover balance. Since the filing of this *Petition*, the Commission heard and approved the 2017 GUIC Rider with modifications,[78] requiring the rider rate to be set to recover costs over a 12-month period, with no carrying charge. The Department does not support implementing a carrying charge because the GUIC Rider mechanism is an optional, extraordinary rate tool, which permits utilities to begin recovery of eligible costs sooner than its next general rate case. The Department recommends no tracker balance carrying charge.

G. TARIFF SHEET AND CUSTOMER NOTICE

In Xcel's Attachment R to its *Petition*, the Company provided both clean and redline formats of its Tariff Sheet No 5-64. Xcel updated the tariff to reflect the combined values of the 2017 and 2018 GUIC Riders. If the Commission modifies the proposed revenue requirement or recovery period, then the Department recommends that the Commission require Xcel to make a compliance filing showing the final Class Factors, and all related tariff changes, within ten days of the date of the order. In addition, should the Commission approve a 2018 GUIC Rider effective period that overlaps temporarily with the current 2017 GUIC Rider, then the Commission should require Xcel to make a second compliance filing showing the Class Factors in effect March 1, 2019, with all related tariff changes, within ten days of the rate change. A subsequent customer billing message should be required and included on first bill with which the change in rate applies.

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[77] Department-calculated rates use the Company-provided expenditures and sales forecast, both of which the Department recommends changes to. Therefore, these rates do not reflect the Department's final proposed rates.
[78] Commission Order issued February 8, 2018 in Docket G002/M-16-891.

Xcel noted that it will provide notice to customers regarding the 2017/2018 GUIC Rider in their monthly gas bills.[79] The following is the Company's proposed language to be included as a notice on customers' bills the month that the 2017/2018 GUIC Rider is implemented:

> This month's Resource Adjustment includes an updated Gas Utility Infrastructure Cost Adjustment (GUIC), which recovers the costs of assessments, modifications and replacement of natural gas facilities as required by state and federal safety programs. The GUIC portion of the Resource Adjustment is $X.XXXX per therm for Residential customers; $X.XXXX per therm for Commercial Firm customers; $X.XXXX for Commercial Demand Billed customers; $X.XXXX per therm for Interruptible customers; and $X.XXXX per therm for Transportation customers.

Xcel noted in its *Petition* that the Company will work with the Department and Commission Staff if there are any suggestions to modify this notice. The Department concludes that the Company's customer notice proposed is the same language used by Xcel in Docket 16-891 and as approved by the Commission in its August 18, 2016 Order in Docket 15-808.

H. PERFORMANCE METRICS

In Docket 15-808, the Commission required Xcel to develop performance metrics and specifically ordered that,

> Xcel shall develop metrics to measure the appropriateness of GUIC expenditures, to be included in future GUIC Rider filings, and provide stakeholders the opportunity for meaningful involvement. Each metric should include a reconciliation to the pertinent TIMP/DIMP rules, and/or if not tied to TIMP/DIMP requirement, the Company must identify what goal, benefit, and/or requirement it addresses.

In Docket 16-891, the Commission order acknowledged that Xcel's proposed metrics were a helpful starting point and thus ordered:

> Xcel shall continue to discuss with other parties, including the Department and the OAG, proposed performance metrics and ongoing evaluation of reporting requirements in future GIUC proceedings.

[79] *Petition*, Pages 34 and 35.

The information the Company provided in Attachment T to its initial filing is responsive to the Commission's prior GUIC orders. Table 8 below summarizes Xcel's proposed GUIC Metrics, results and conclusion as follows:

Table 8

Program	Metric	Measurement	Result	Conclusion
DIMP	Leak Rate by Vintage and Pipe Type	Monitor the impact of renewal efforts on leakage rates. Selection of higher-risk pipe segments will lower leakage rates over time.	Trending down since 2011 (Figure 2 of Attch. T, coated steel pipe)	3-Yr leak survey cycle contributes to Year-to-year variations
	Poor Performing main Replacement Unit Cost	Monitor unit costs greater than one standard deviation above the mean to ensure variances are understood and reasonable.	One project in 2016 had unit cost > one-stndrd deviation (Dwntwn StP)	Unit costs may vary for differences in soil, paving, traffic control and permit needs.
	Poor Performing Service Replacements Unit Cost	Monitor unit costs greater than one standard deviation above the mean to ensure variances are understood and reasonable.	Nine projects in 2016 were ± one-stndrd deviation	Unit cost variance attributed to svc Line length differences and opportunity to coordinate w/ city-planned projects, which reduces restoration costs
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.	22 repairs in 2013. None repaired in years 2014-2016 (Figure 5 of Attch. T)	Number of repairs expected to vary year-to-year as different pipelines are inspected.
	Actual vs. Estimated Cost Variance Explanations for Capital Projects	Monitor cost variances to ensure variance are understood and reasonable.	Actual costs approximated estimates (Table 4, Attch. T, incl. footnotes 1,2)	Variances attributed to schedule delays, excess dewatering of site, lower contract labor cost.

The Department reviewed the results of Xcel's metrics and generally concludes they are reasonable, with one exception. For the DIMP Poor Performing Main Unit Cost metric, one project stood well apart from all the others in terms of its per foot unit cost, yet Xcel included its costs when calculating the standard deviation threshold.[80] Including the outlier project caused only one project, the outlier itself (*i.e*., the downtown St. Paul project) to appear to be the only project having a cost deviation beyond the normal range. Xcel Gas could have excluded the outlier project in its statistical calculations, and if it had done so, there would have been six additional projects that would require further examination of their cost variances. The Department requests that in its reply comments, Xcel provide an evaluation of those additional six projects that have unit cost variances that exceed one standard deviation calculated without the outlier Downtown St. Paul project unit costs.

IV. DEPARTMENT REPLY TO XCEL ENERGY'S MAY 29, 2018 SUPPLEMENTAL COMMENTS ON GUIC RIDER PETITION AND DEPRECIATION IMPACTS FROM XCEL'S FIVE-YEAR STUDY DOCKET NO. E,G002/D-17-581

A. COMMISSION NOTICE

The Commission Notice issued on May 2, 2018, requested comments related to Xcel Gas' $6.8 million reduction in annual depreciation expense, starting in 2018, resulting from its depreciation revisions approved in Docket No. E,G002/D-17-581. The notice identified the topics open for discussion as follows:

- Should the Commission address the $6.8 million decrease in depreciation expense discussed in Xcel Energy's five-year depreciation study (Docket No. E,G-002/D-17-581) in Xcel Energy's Gas Utility Infrastructure Cost (GUIC) rider petition, in this docket?
- If so, how should the Commission address the decrease in depreciation expense (e.g. with a corresponding adjustment) in the GUIC petition? If not, why not?
- How should the Commission handle similar issues in the future?
- Are there other issues or concerns related to this matter?

B. XCEL ENERGY'S SUPPLEMENTAL COMMENTS

Xcel Energy filed comments on May, 29, 2018 to discuss whether to reflect Xcel Gas' $6.8 million reduction in annual depreciation expense in its GUIC Rider. Xcel stated it fully intends to incorporate the new depreciation rates for GUIC projects in the 2018 GUIC Rider revenue requirements, estimating the impact to be a $540,000 reduction. However, Xcel argues against the inclusion of the remaining annual depreciation expense reduction, which stems from non-GUIC capital, because it would be inappropriate and would violate the Commission's policy

[80] The Downtown St. Paul project unit cost exceeded $325 per foot, whereas all other measured activities were less than $100 per foot.

against single-issue ratemaking. Xcel posits that the proper venue to incorporate the non-GUIC depreciation changes would be in a future rate case.

Xcel Gas' last rate case set general rates based on a 2010 test year.[81] Xcel argues that since then it has experienced various cost increases unrelated to GUIC projects, which are not factored into its base rates. Therefore, Xcel concluded that it is not appropriate to isolate this single expense decrease outside of a rate case without consideration given to all of the cost changes over these past eight years. Xcel also pointed out, as illustrated in Xcel's Table 1 to its May 29 supplemental comments, that its annual depreciation expense has increased by nearly $6.9 million from non-GUIC capital investments alone, which outstrips the decrease approved in Docket 17-581.

C. DEPARTMENT'S REPLY COMMENTS

The Department concluded that the GUIC Rider should not incorporate the study's impact on the non-GUIC projects depreciation expense because doing so would fragment non-GUIC asset recovery, would be single issue ratemaking, and appears to extend beyond the scope of the GUIC statute.

1. Fragment Asset Recovery

In regulated utility ratemaking, for its plant investments, utilities typically are authorized to earn a *return on* their investments as well as a *return of* their investment. Despite the fact that the *return on and return of* dollars represent two types of costs, these costs are linked and are tied to a common item. (The accumulated "return of" dollars reduce the principal on which the "return on" amount is determined.) In the Department's view, to update a GUIC Rider rate to account for a dollar change in "return of" the non-GUIC common asset without regard to any change in the asset investment-to-date and without updating a tariff rate for any impact such change has on the "return on" dollars, would not be fair or reasonable. Further, to carve out a portion of an asset's particular cost element for cost recovery, in an irregular manner that causes the asset's cost element to be reflected within multiple rate mechanisms established at different points in time, would complicate rate review and regulatory oversight.

2. Single Issue Ratemaking

The concept of a test year is to establish just and reasonable base rates by reviewing a utility's entire operations at a normal operating level. It is not unusual that from year-to-year costs, sales volumes, or customer counts may vary, either up or down. Nor is it unusual that in a capital-intensive industry, depreciation expense is a material cost. Even so, to include in the GUIC rider a change in one ordinary base rate cost that occurs many years after a rate case,

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

which is not a product of the rider-based activity, and without consideration of other inputs that established the base rate, would disregard the fact that the test-year's purpose and function is to set representative and reasonable rates. Therefore, the Department concludes that to consider inclusion of Xcel Gas' annual depreciation expense changes unrelated to the GUIC projects would be single-issue ratemaking and should not be included in this rider. However, as discussed in Section III.D.1.b.ii previously, the Department recommends that the Commission require Xcel Gas' to incorporate the newly approved depreciation rates when determining the depreciation expense for GUIC Rider projects.

Putting the single issue ratemaking aside, the Department reviewed and compared Xcel Gas' 2017 normalized operations shown in its jurisdictional annual reports, to its approved 2010 test year (See Table 9 below).

Table 9

Comparison of Xcel Gas Rate Case 2010 Test Year to Reported 2017 Operations
$000s

Line No.		**2010 Test Yr** 1/	**2017 JAR** 2/	***Change from 2010-to-2017*** (col. B - A)	**or % Δ**	**2017 GUIC** 3/	***Change without GUIC $*** (col. C - D)
		A	B	C	C.1	D	E
1	Plant in Service (Average)	937,311	1,222,545	*285,234*	*30%*	92,656	*192,579*
2	Depreciation Expense	32,684	41,845	*9,161*	*28%*	2,265	*6,896*
3	Overall Average Rate Base	438,315	533,264	*94,949*	*22%*	81,425	*13,524*
4	Operating Income + AFUDC	36,292	37,398	*1,106*	*3%*	5,697	*(4,591)*
5	Overall Rate of Return	8.28%	7.01%			7.02%	
6	Return on Equity	10.09%	9.16%			9.04%	

Source:
1/ Docket No. G002/GR-09-1153
2/ Docket No. E,G999/PR-18-04
3/ Docket No. G002/M-17-787 Supplement Filing; Rate Base is averaged monthly - value is the 13-mo. average.

The Department confirmed Xcel's assessment that its 2017 annual depreciation expense increase over the amount included in its last rate case outstrips the approved reduction (Table 9, Line 2, columns C and E). In addition, Xcel Gas' plant in service has increased by $285.2 million with GUIC projects included, or $192.6 million with GUIC projects excluded (Table 9, Line 1, columns C and E). From this information, one could conclude that Xcel has continued to invest in its system since its last rate case outside of rider incentives.[82] Also noted is that Xcel Gas' reports that its operating income, while unaudited by regulators, increased by $1.1 million with GUIC rider revenue, but when GUIC rider revenue is removed, operating revenue decreased by $4.6 million (Table 9, Line 4, columns C and E). Despite the smaller growth in operating income relative to its reported change in plant investment, Xcel Gas calculated a normalized return on equity of 9.16 percent for 2017; this reported level is due in part to lower debt costs.

3. Scope of the GUIC Statute

The Department believes that inclusion of changes in depreciation expense stemming from non-GUIC operations would capture changes that are beyond the rider's statutory framework. The Department also notes that the non-GUIC cost changes, in part, could be linked to or are a product of betterments and/or connecting new customers; costs related to these reasons are specifically to be excluded from this rider. In fact, Xcel Gas' average number of customers has grown by approximately 21,000 since its last rate case.[83] Therefore, inclusion of Xcel Gas' overall annual depreciation expense does not appear to be supported by Minn. Stat. § 216B. 1635. The following are parts of the statute that led the Department to its conclusion.

Section 216B.1635, Subd. 2 states in part:

> A public utility submitting a petition to recover gas infrastructure costs under this section must submit to the commission, the department, and interested parties a gas infrastructure project plan report and a petition for rate recovery of only incremental costs associated with projects under subdivision 1, paragraph (c).

The referenced Section 216B.1635, Subd. 1, paragraph (c), reads:

> (c) "Gas utility projects" means:
> (1) replacement of natural gas facilities located in the public right-of-way required by the construction or improvement of a highway, road, street, public building, or other public work by or on behalf of the United States, the state of Minnesota, or a political subdivision; and (2) replacement or modification of existing natural gas facilities, including surveys, assessments, reassessment, and other work necessary to determine the need

[82] In addition to the GUIC Rider, Xcel Gas has a SEP Rider which recovers infrastructure investments which sums to a reported $13.7 million plant-in-service at 2017 year-end (Docket G002/18-184, Schedule D2).
[83] Average number of customers included in Xcel Gas' 2010 test year totaled 434,203, whereas the 2017 JAR report (Tab 38) reported a total of 455,430 average number of customers; 455,430 – 434,203 = 21,227 increase, or approximately a 4.9% increase.

> for replacement or modification of existing infrastructure that is required by a federal or state agency.

And Section 216B.1635, Subd. 4 reads:

> Subd. 4. Cost recovery petition for utility's facilities.
> Notwithstanding any other provision of this chapter, the commission may approve a rate schedule for the automatic annual adjustment of charges for gas utility infrastructure costs net of revenues under this section

Section 216B.1635, Subd 1(b) provides the definition of gas utility infrastructure costs, which reads:

> (b) "Gas utility infrastructure costs" or "GUIC" means costs incurred in gas utility projects that:
> (1) do not serve to increase revenues by directly connecting the infrastructure replacement to new customers;
> (2) are in service but were not included in the gas utility's rate base in its most recent general rate case, or are planned to be in service during the period covered by the report submitted under subdivision 2, but in no case longer than the one-year forecast period in the report; and
> (3) do not constitute a betterment, unless the betterment is based on requirements by a political subdivision or a federal or state agency, as evidenced by specific documentation, an order, or other similar requirement from the government entity requiring the replacement or modification of infrastructure.

Nowhere does the statute refer to non-GUIC costs; as a result, the Department concludes that it would not be appropriate to include changes in non-GUIC costs in the GUIC rider.

V. CONCLUSIONS AND RECOMMENDATIONS

Based on its review, the Department concludes that Xcel's continued recovery of the GUIC Rider is reasonable. However, the Department recommends modifications to Xcel's proposed 2018 GUIC Rider.

The Department recommends that Xcel provide the following in Reply Comments:

- An updated forecast, without the historical monthly adjustment;

- Clarification as to why forecasted sales for 2018 and 2019 are so much lower than actual sales reported in the GJAR for 2016 and 2017.
- The reporting required by Minn. Stat. § 216B.1635, Subd. 4 (2) (iii);
- Clarify: 1) the extent to which the additional 207 miles of intermediate pressure pipelines are subject to MAOP regulations (49 CFR 192.619), and 2) any updates or other information on these lines that may be helpful;
- Identify all completed and proposed GUIC projects that change the classification of the gas pipeline/plant system (i.e., from transmission-to-distribution or vice versa), explaining the characteristics that caused the reclassification. The Reply Comments should also detail the cost allocation treatment of that gas system infrastructure and its associated O&M costs between Minnesota and North Dakota before and after such classification change; Likewise, identify all NSP gas system integrity management projects undertaken or planned in North Dakota that affect the cost allocation treatment of that gas system infrastructure and/or associated O&M between North Dakota and Minnesota; and
- For the DIMP Poor Performing Main Unit Cost performance metric, provide an analysis of costs for each of the projects that have unit cost variances which exceed one standard deviation calculated without the outlier Downtown St. Paul project unit costs.

The Department also recommends that the Commission:

- direct the Company to include the reporting required by Minn. Stat. § 216B.1635, Subd. 4 (2) (iii) in future GUIC rider petitions;
- require Xcel to include only incremental rate base amounts in its GUIC rider rate base; Alternatively, if Xcel Gas cannot reasonably determine the remaining book value of existing plant included in base rates since removed or retired due to GUIC projects, then direct Xcel Gas to do away with the adjustments to the GUIC rider accumulated depreciation reserve attributed to the removal costs of the old plant;
- require the Company to recalculate the incremental depreciation expense amount by accounting for the depreciation expense amounts included in base rates relevant to the plant assets replaced by (or retired through) the GUIC projects included in this rider. Any previously overstated revenue requirements should be credited back to ratepayers;
- Direct the Company to incorporate and apply the Commission-decided depreciation factors in Docket E,G002/D-17-581, when calculating GUIC-projects' depreciation in this *Petition*;
- require Xcel to recalculate the incremental property tax expense amount for all GUIC years by adjusting original cost of GUIC projects by the original cost of plant assets replaced by (or retired through) the GUIC projects in each year, prior to applying Xcel's calculated property tax rate. Any overstated revenue requirements should be credited back to ratepayers;

- Maintain Xcel Gas' rider authorized Rate of Return at 7.02%;
- direct that the implementation of the 2018 GUIC Rider to be effective no sooner than January 1, 2019 to recovery the 2018 GUIC Rider revenue requirements over a 12-month recovery period;
- Consider limiting the "return on" the capital costs incurred to remediate the system's MAOP data gaps, to Xcel Gas' long-term debt costs;
- For the TIMP Island Line South Project, direct Xcel to exclude the $0.6 million estimated costs of the ILI assessments to be performed on the Island Line South pipeline designated to be replaced and direct Xcel to remove the $1.5 million cost overruns from the GUIC rider recovery;
- require that the Langdon Line project amount includable in the GUIC rider rate base be adjusted and reduced by the project's cost differential between use of a 12-inch and an 8-inch pipe, should the Company elect to use a 12-inch diameter pipe instead of an 8-inch diameter pipe. Xcel estimated this cost differential to be approximately $3.6 million;
- Direct Xcel to exclude $420,000 of the H005 project costs be excluded from GUIC recovery rider;
- Direct Xcel to remove $85,000 in costs incurred on low-risk infrastructure replacement costs that were not required by civic/public work requirements, nor required by government regulations;
- Determine no carrying charge on the GUIC tracker balance;
- Direct the Company to remove from the GUIC Rider $8,276,882 in capital costs not already removed, unless the Company can adequately demonstrate that these costs are Minnesota-specific and incremental to costs captured in base rates;
- Direct the Company to use a jurisdictional allocator for all costs identified in Attachment 20, Table 3, unless the Company can provide invoices and work orders related to all of these charges;
- Direct the Company to remove the work that is not Minnesota-specific, as identified by the Company in response to IR 62;
- Require Xcel, in future GUIC filings, to present historical and projected GUIC revenue requirements, rates, and recoveries within a single tracker for each year;
- Require Xcel to make a compliance filing showing the final rate-adjustment factors and all related tariff changes, within ten days of the date of the *Order*;
- In the event the 2017 GUIC rate and 2018 GUIC rate overlap, require Xcel to make a second compliance filing showing the final rate-adjustment factors in effect as of March 1, 2019, within 10 days of the rate change; in addition, require Xcel to include the Commission-approved billing message on customers' first bills to which the new rate applies.

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Xcel Energy			
Docket No.:	G002/M-17-787		
Response To:	MN Department of Commerce	Information Request No.	51
Requestor:	Dorothy Morrissey, Danielle Winner		
Date Received:	April 2, 2018		

Question:

Topic: Bill Impacts
Reference(s): Attachment Q in March 27, 2018 Supplement

Request:

A. For each rate class, please provide a comparison of the Company's Minnesota-customers average usage over a continuous 12-month period and the average usage during the 7-month period August through February.

B. Using the same average customer usage during the 7-month period August through February (Part A), for each rate class please provide the average bill impact during this 7-month period, assuming the Company's proposal to overlap the collections of its 2017 and 2018 GUIC revenue requirement collections is approved.

C. Please provide the bill impact to each customer class following the end of the proposed overlapped rate-period, (1) compared to the rates proposed to be in effect during the 7-month period August through February, and (2) compared to the rates in effect prior to the 7-month period.

Response:

A. Please see the following table for the Company's Minnesota-customers average monthly usage over the 12-month period August 2018 through July 2019 and the average monthly usage over the 7-month period August through February:

Minnesota Customers Average Monthly Use per Customer (Therms)

Rate Class	12 Months Aug18-Jul19	7 Months Aug18-Feb19
Residential	70	87
Commercial Firm	480	587
Commercial Dmd Bill	16,990	18,707
Interruptible	22,775	25,752
Transport	663,538	636,728

B. The following table shows the average monthly bill impact during the 7-month overlap period (August 2018 through February 2019):

Average Monthly Bill Impact

Rate Class	Aug18-Feb19 Proposed Factor	Aug18-Feb19 Avg Usage (Therms)	Avg Bill Impact
Residential	$0.081419	87	$7.09
Commercial Firm	$0.045569	587	$26.76
Commercial Dmd Bill	$0.036475	18,707	$682.32
Interruptible	$0.026379	25,752	$679.32
Transport	$0.010157	636,728	$6,467.11

C. Please see the following tables for a comparison of the period prior (April 2018 through July 2018), to the proposed overlapped period (August 2018 through February 2019), and the period after the proposed overlapped period (March 2019).

Proposed Factors ($/Therm)

Rate Class	(Apr18-Feb19) 2017 Recovery (A)	(Aug18-Mar19) 2018 Recovery (B)	(Aug18-Feb19) Combined (C)
Residential	$0.027634	$0.053784	$0.081419
Commercial Firm	$0.015080	$0.030490	$0.045569
Commercial Dmd Bill	$0.011332	$0.025143	$0.036475
Interruptible	$0.008114	$0.018265	$0.026379
Transport	$0.003287	$0.006870	$0.010157

Average Monthly Use per Customer (UPC) in Therms

Rate Class	Apr18-Jul18 (D)	Aug18-Feb19 (E)	Mar19 (F)
Residential	32	87	108
Commercial Firm	224	587	754
Commercial Dmd Bill	12,692	18,707	22,101
Interruptible	15,670	25,752	29,284
Transport	706,749	636,728	484,564

Average Monthly Bill Impact (Proposed Factors * UPC)

	Apr18-Jul18	Aug18-Feb19			Mar19
	2017 Recovery	2017 Recovery	2018 Recovery	Combined Recovery	2018 Recovery
Rate Class	(A*D)	(A*E)	(B*E)	(C*E)	(B*F)
Residential	$0.89	$2.41	$4.68	$7.09	$5.80
Commercial Firm	$3.38	$8.86	$17.90	$26.76	$22.99
Commercial Dmd Bill	$143.83	$211.99	$470.33	$682.32	$555.68
Interruptible	$127.15	$208.95	$470.36	$679.32	$534.88
Transport	$2,323.15	$2,092.98	$4,374.12	$6,467.11	$3,328.80

Preparer: Christopher Barthol
Title: Principal Pricing Analyst
Department: NSPM Regulatory
Telephone: 612-321-3237
Date: April 12, 2018

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Xcel Energy
Docket No.: G002/M-17-787
Response To: MN Department of Commerce Information Request No. 55
Requestor: Dorothy Morrissey, Danielle Winner
Date Received: April 5, 2018

Question:

Topic: TIMP Programmatic Replacement and MAOP Remediation
Reference(s): Response to DOC IR No. 19

Request:

A. Regarding response to Part A of DOC IR No. 19, please explain why the Company has incomplete maximum allowable operation pressure (MAOP) records for 21 percent of its gas transmission miles.

B. Please identify both the short- and the long-term remediation actions that the Company will undertake to satisfy the MAOP pipeline safety requirements for the 21 percent of transmission pipelines identified as incomplete and provide the timeframe and total projected costs to do so.

Response:

A. Prior to the MAOP Remediation Advisory Bulletin[1] issued in 2012, the requirement that records be traceable, verifiable and complete (TVC) did not exist, and some of the Company's MAOP records do not meet the new criteria. Additionally, some of the Company's gas transmission pipelines were constructed prior to the enactment of Federal Pipeline Safety Rules in 1970, which specified the requirements for establishing MAOP.

B. The Company evaluates gas transmission pipelines for TIMP MAOP risk per the quantitative risk assessment methodology on page 15 of Petition Attachment C2. Those MAOP projects identified as medium and high risk, which requires remediation, are those lacking TVC records that demonstrate compliance with test pressure requirements established in 49CFR Part 192.619(a)(2). Pipelines that do not have TVC records of pipe material but have satisfactory test pressure records are evaluated as low risk and do not require remediation under current regulatory requirements. The table below shows the capital projects the Company has identified for remediation.

TIMP MAOP Pipeline Project	Approximate Project Length	Timeframe - Years
County Road B (NSP to Rice)	6.5 miles	2018-2020
East County Line (30-inch Maplewood Propane to North St. Paul)	1.4 miles	2018-2019
East County Line (30-inch SSP to RR Tracks)	0.6 miles	2017-2018
Island Line North Valve Header	0.05 miles	2023-2025

The Company has identified that the TIMP MAOP risk score shown on Page 15 of Petition Attachment C2 for the Crossover Pipeline Project between Upper 55 to South St. Paul Regulator Station was not correct. The assessment incorrectly identified that the Crossover Line lacked a TVC pressure test. As a result, the risk score of 9.6 shown is not correct and should instead be 1.6, which is considered Low Risk. This 12-inch gas transmission pipeline was installed in 1946 prior to the enactment of Federal Pipeline Safety regulations, and the Company does not have records that the pipeline was pressure tested prior to being placed into service. However, in preparing the risk score for this project, Company engineers failed to take account of a pressure test that was completed in 2015. We still consider this an important project and plan to complete it as a part of our normal capital work. However, because of the revised low risk score, the Company will not pursue recovery of this project as part of the GUIC.

Removing the Crossover Pipeline Project from the GUIC request will result in decreases of $4,140 in the 2017 GUIC revenue requirement and $100,094 in the 2018 GUIC revenue requirement. Rather than recalculating the already approved rate factors for the 2017 GUIC revenue requirement, we propose to reduce our 2018 GUIC revenue requirement by $104,234 to account for the impact from both 2017 and 2018. We intend to file update schedules reflecting this adjustment in our Reply Comments in this docket.

The Company has reviewed all risk scores reported in Petition Attachments C2 and D2(a) and found the errors described below:

i. Calculation errors exist in the DIMP Intermediate Pressure (IP) Line Replacements Project Risk on Attachment D2(a), page 6. The corrected values are shown in the table below. Company Engineers incorrectly added scores for corrosion, third-party damage, and other leak factors instead of using only the maximum score. To illustrate, the corrected score for the Langdon Line project is:

Risk Score (G) =
Likelihood of Failure
x Consequence of Failure (F = 3)

Likelihood of Failure =
Mechanical Joint Risk Factor (A = 2)
+ Manufacturing/Construction Risk Factor (B = 2)
+ Maximum Score of:
Corrosion Risk Factor (C = 1),
3rd Party Damage Risk Factor (D = 1),
Other Leak History Factor (E = 0)

Thus, Risk Score = (2 + 2 + 1) * 3 = 15

Project	A Mechanical Joint	B Manufacturing / Construction Defect	C Corrosion	D 3rd Party Damage	E Other Leak History	F Consequence	G Risk Score	Project Classification
Colby Lake Lateral	0	2	1	1	1	3	~~15~~ 9	~~High~~ Medium
H005 – Lexington to Snelling	2	2	1	1	1	3	~~21~~ 15	High
Langdon Line (TBS to Ashland)	2	2	1	1	0	3	~~18~~ 15	High

ii. The risk level reported for DIMP Sewer and Gas Line Conflict projects on Petition Attachment D2(a), page 14 of 22 are reported as High Risk. These projects will also include work near residential single family structures and thus should be more accurately described as a mixture of medium and high risk as shown in the corrected table below:

Polygon ID	City	State	Project	Estimated Service Count	Risk Scores	Risk Level
372455262	Roseville	MN	County Rd C2 W and Western Ave	784	~~6~~ 3	~~High~~ Medium 3
359596126	Vadnais Heights	MN	Berwood and Arcade	1168	~~6~~ 3	~~High~~ Medium 3
372455266	Faribault	MN	8th St and 4th Ave	969	~~6~~ 3	~~High~~ Medium 3
372455270	Sauk Rapids	MN	11th St N and 9th St N	869	~~6~~ 2-	~~High~~ Medium 3
372455278	Cottage Grove	MN	80th St S and Hwy 61	3619	~~6~~ 3	~~High~~ Medium 3
Total Inspections				*7,408		

The corrected scores shown in the tables above remain in the Medium classification. These errors do not have any material impact on our proposal, as both high and medium risk projects are included as a part of the GUIC.

[1] On May 7, 2012, the Pipeline and Hazardous Materials Safety Administration (PHMSA) issued an Advisory Bulletin to clarify the record verification requirements for establishing Maximum Allowable Operating Pressure (MAOP) for natural gas pipelines. See http://www.gpo.gov/fdsys/pkg/FR-2012-05-07/pdf/2012-10866.pdf.

Preparer: Eric Kirkpatrick
Title: Director
Department: Gas Engineering & Project Management
Telephone: 303-571-3223

Date: April 19, 2018

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Xcel Energy
Docket No.: G002/M-17-787
Response To: MN Department of Commerce Information Request No. 14
Requestors: Dorothy Morrissey, Danielle Winner
Date Received: January 30, 2018

Question:

Topic: TIMP Revenue Requirements
Reference(s): Attachment F

A. Please provide an electronic copy of Attachment F with formulae intact.

B. Please reference the current income tax calculation. Please explain what "CPI-Tax Interest (If Applicable)" is and explain the basis for its inclusion.

C. Please explain how the "deferred taxes" amount was computed and explain why its value remains constant for each month within a calendar year.

D. Regarding notes to TIMP Project Costs tables found on pages 4, 15 and 22 of Attachment C: Please identify the amount of RWIP (removal work in progress) costs included in Attachment F "Plant in Service" amounts.

Response:

A. Please see Attachment A to this response for an electronic copy of Attachment F to the Petition, with formulae intact.

B. CPI stands for Construction Period Interest, which is capitalized and included in the tax basis used for tax depreciation of property only. It is sometimes also referred to as "Avoided Tax Interest." It is not reflected in the plant in-service or construction work in progress amounts.

IRS Publication 535 offers the following guidance in regards to CPI:

- "Under the uniform capitalization rules, you generally must capitalize interest on debt equal to your expenditures to produce real property or certain tangible personal property.
- "Treat capitalized interest as a cost of the property produced. You recover your interest when you sell or use the property…If the property is used in your trade or business, recover capitalized interest through an adjustment to basis, depreciation, amortization or other method."

It is reasonable to include an avoided tax interest component related to the computation of taxable income because it represents an imputed interest that is considered taxable income during the construction period of an asset pursuant to Internal Revenue Service rules. For that reason, we have consistently included an avoided tax interest component in our past rider filings.

Avoided tax interest is computed by applying an imputed IRS-defined interest rate which is calculated based on the "avoided cost method" to the average monthly CWIP balance during the construction period of an asset. Under the "avoided cost method," any interest that theoretically would have been avoided if accumulated construction expenditures had been used to repay or reduce outstanding debt must be capitalized and included in both taxable income and the tax depreciable basis of an asset. All amounts added to taxable income are also added to the tax depreciable basis of the asset and deducted through the computation of tax depreciation

C. The "deferred taxes" amount is the difference between book depreciation and tax depreciation multiplied by the corporate composite tax rate. This is an annual calculation spread evenly across the previous 12 months. Thus, the deferred tax amount will not change by month throughout the year. We note that monthly amounts for actuals are not fully known until the full year completes, even though other components of monthly actuals can be known as each given month is recorded.

D. RWIP is not included in Plant in Service amounts but is reflected in Net Plant. RWIP expenditures close against accumulated book depreciation reserve and affect rate base by changing the accumulated book depreciation reserve. Positive RWIP balances decrease the accumulated book depreciation reserve.

Below is a summary of the CWIP and RWIP included in TIMP Net Plant.

($ millions)	2016	2017	2018
TIMP			
CWIP *(Attachment E)*	$18.75	$8.93	$8.72
RWIP	$2.96	$0.38	$0.31
Total Capital Expenditures	**$21.71**	**$9.31**	**$9.03**
Petition Attachment C Reference	*Page 22*	*Page 15*	*Page 4*

Preparer: James Aurand
Title: Senior Rate Analyst
Department: Revenue Requirements – North
Telephone: 612-337-2076
Date: February 9, 2018

Northern States Power Company

TIMP - Capital Revenue Requirements	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Total
Rate Base													
CWIP	-	-	-	-	-	-	-	-	-	-	-	-	-
Plant In-Service	41,002,201	41,224,699	41,221,031	41,358,584	41,362,685	48,647,724	47,049,533	52,672,931	54,706,235	52,527,236	55,163,535	59,397,911	59,397,911
Less Accumulated Book Depreciation Reserve	(135,999)	(50,939)	34,589	120,256	206,070	296,627	396,067	493,430	605,136	716,688	828,720	946,473	946,473
Less Accumulated Deferred Taxes	3,463,723	3,642,527	3,821,330	4,000,134	4,178,937	4,357,740	4,536,544	4,715,347	4,894,151	5,072,954	5,251,757	5,430,561	5,430,561
End Of Month Rate Base	37,674,476	37,633,111	37,365,112	37,238,194	36,977,678	43,993,356	42,116,923	47,464,154	49,206,948	46,737,594	49,083,057	53,020,878	53,020,878
Average Rate Base (Prior Mo + Cur Month/2)	37,883,755	37,653,793	37,499,111	37,301,653	37,107,936	40,485,517	43,055,139	44,790,538	48,335,551	47,972,271	47,910,326	51,051,968	
Return on Rate Base													
Debt Return (Avg RB * Wtd Cost of Debt)	71,663	71,228	70,936	70,562	70,196	76,585	81,446	84,729	91,435	90,748	90,630	96,573	966,732
Equity Return (Avg RB * Wtd Cost of Equity)	159,743	158,773	158,121	157,289	156,472	170,714	181,549	188,867	203,815	202,283	202,022	215,269	2,154,917
Total Return on Rate Base	231,407	230,002	229,057	227,851	226,668	247,299	262,995	273,596	295,250	293,031	292,652	311,842	3,121,649
Income Statement Items													
AFUDC Pre-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-
Property Taxes	58,295	58,295	58,295	58,295	58,295	58,295	58,295	58,295	58,295	58,295	58,295	58,295	699,538
Book Depreciation	85,242	85,299	85,528	85,667	85,814	93,467	99,439	103,666	111,704	111,552	112,032	117,752	1,177,163
Deferred Taxes	178,803	178,803	178,803	178,803	178,803	178,803	178,803	178,803	178,803	178,803	178,803	178,803	2,145,641
Gross Up for Income Tax (see below)	92,641	90,891	87,981	76,831	82,003	106,734	113,703	130,633	136,871	(1,152,909)	1,073,114	(1,462,144)	(623,649)
Total Income Statement Expense	414,982	413,289	410,607	399,596	404,915	437,299	450,241	471,398	485,674	(804,259)	1,422,244	(1,107,293)	3,398,693
Total Revenue Requirement	**646,388**	**643,291**	**639,664**	**627,447**	**631,583**	**684,599**	**713,236**	**744,993**	**780,924**	**(511,228)**	**1,714,896**	**(795,451)**	**6,520,342**
Capital Structure													
Weighted Cost of Debt	2.27%												
Weighted Cost of Equity	5.06%												
Required Rate of Return	7.33%												
Current Income Tax Calculation													
Equity Return	159,743	158,773	158,121	157,289	156,472	170,714	181,549	188,867	203,815	202,283	202,022	215,269	2,154,917
Book Depreciation	85,242	85,299	85,528	85,667	85,814	93,467	99,439	103,666	111,704	111,552	112,032	117,752	1,177,163
Deferred Taxes	178,803	178,803	178,803	178,803	178,803	178,803	178,803	178,803	178,803	178,803	178,803	178,803	2,145,641
Less Tax Depreciation	292,496	294,064	298,157	314,373	309,691	299,354	309,528	299,258	315,276	2,145,430	(1,005,281)	2,595,461	6,467,808
Plus CPI-Tax Interest (If Applicable)	-	-	392	1,499	4,817	7,635	10,877	13,057	14,929	18,877	22,690	11,471	106,244
Total	131,292	128,812	124,688	108,885	116,215	151,265	161,141	185,135	193,976	(1,633,915)	1,520,828	(2,072,165)	(883,843)
Tax Rate (T/(1-T)	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611
Gross Up for Income Tax	92,641	90,891	87,981	76,831	82,003	106,734	113,703	130,633	136,871	(1,152,909)	1,073,114	(1,462,144)	(623,649)

Northern States Power Company

TIMP - Capital Revenue Requirements	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Total
Rate Base													
CWIP	-	-	-	-	-	-	-	-	-	-	-	-	-
Plant In-Service	59,405,130	59,491,425	59,499,445	59,770,146	60,147,335	60,459,921	60,762,999	60,956,906	62,773,002	64,337,448	65,967,643	68,222,346	68,222,346
Less Accumulated Book Depreciation Reserve	1,067,185	1,187,967	1,308,815	1,429,952	1,551,664	1,673,922	1,796,636	1,915,747	(2,703,454)	(4,096,618)	(4,529,778)	(4,636,295)	(4,636,295)
Less Accumulated Deferred Taxes	5,540,657	5,650,753	5,760,850	5,870,946	5,981,042	6,091,138	6,201,235	6,311,331	6,421,427	6,531,523	6,641,620	6,751,716	6,751,716
End Of Month Rate Base	52,797,288	52,652,705	52,429,780	52,469,248	52,614,630	52,694,860	52,765,129	52,729,829	59,055,029	61,902,543	63,855,801	66,106,926	66,106,926
Average Rate Base (Prior Mo + Cur Month/2)	52,909,083	52,724,997	52,541,243	52,449,514	52,541,939	52,654,745	52,729,995	52,747,479	55,892,429	60,478,786	62,879,172	64,981,364	
Return on Rate Base													
Debt Return (Avg RB * Wtd Cost of Debt)	100,086	99,738	99,391	99,217	99,392	99,605	99,748	99,781	105,730	114,406	118,946	122,923	1,258,962
Equity Return (Avg RB * Wtd Cost of Equity)	220,014	219,248	218,484	218,103	218,487	218,956	219,269	219,342	232,419	251,491	261,473	270,214	2,767,499
Total Return on Rate Base	320,100	318,986	317,875	317,320	317,879	318,561	319,016	319,122	338,149	365,897	380,419	393,137	4,026,461
Income Statement Items													
AFUDC Pre-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-
Property Taxes	84,131	84,131	84,131	84,131	84,131	84,131	84,131	84,131	84,131	84,131	84,131	84,131	1,009,577
Book Depreciation	120,713	120,781	120,848	121,137	121,711	122,259	122,713	123,037	124,815	127,785	130,463	133,844	1,490,106
Deferred Taxes	110,096	110,096	110,096	110,096	110,096	110,096	110,096	110,096	110,096	110,096	110,096	110,096	1,321,155
Gross Up for Income Tax (see below)	51,010	33,139	62,311	76,346	55,426	47,398	4,845	(9,712)	56,764	73,900	84,461	94,302	630,189
Total Income Statement Expense	365,951	348,147	377,387	391,711	371,365	363,884	321,786	307,552	375,806	395,913	409,152	422,373	4,451,028
Total Revenue Requirement	**686,051**	**667,134**	**695,261**	**709,031**	**689,244**	**682,445**	**640,802**	**626,675**	**713,955**	**761,809**	**789,571**	**815,510**	**8,477,489**
Capital Structure													
Weighted Cost of Debt	2.27%												
Weighted Cost of Equity	4.99%												
Required Rate of Return	7.26%												
Current Income Tax Calculation													
Equity Return	220,014	219,248	218,484	218,103	218,487	218,956	219,269	219,342	232,419	251,491	261,473	270,214	2,767,499
Book Depreciation	120,713	120,781	120,848	121,137	121,711	122,259	122,713	123,037	124,815	127,785	130,463	133,844	1,490,106
Deferred Taxes	110,096	110,096	110,096	110,096	110,096	110,096	110,096	110,096	110,096	110,096	110,096	110,096	1,321,155
Less Tax Depreciation	381,646	405,544	363,714	343,963	374,676	386,874	447,841	469,417	390,576	389,584	387,771	385,156	4,726,762
Plus CPI-Tax Interest (If Applicable)	3,115	2,382	2,594	2,826	2,932	2,735	2,629	3,179	3,692	4,943	5,439	4,648	41,113
Total	72,292	46,964	88,308	108,199	78,551	67,173	6,867	(13,764)	80,446	104,731	119,699	133,645	893,111
Tax Rate (T/(1-T)	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611
Gross Up for Income Tax	51,010	33,139	62,311	76,346	55,426	47,398	4,845	(9,712)	56,764	73,900	84,461	94,302	630,189

Northern States Power Company

TIMP - Capital Revenue Requirements	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Total
Rate Base													
CWIP	-	-	-	-	-	-	-	-	-	-	-	-	-
Plant In-Service	68,723,162	69,018,830	69,246,855	69,526,617	69,832,343	70,330,018	70,969,160	71,964,909	75,047,409	76,017,765	76,810,635	77,452,797	77,452,797
Less Accumulated Book Depreciation Reserve	(4,609,154)	(4,525,570)	(4,417,708)	(4,299,168)	(4,175,772)	(4,055,584)	(3,939,973)	(3,832,383)	(3,722,671)	(3,607,184)	(3,482,830)	(3,458,473)	(3,458,473)
Less Accumulated Deferred Taxes	6,869,006	6,986,297	7,103,588	7,220,878	7,338,169	7,455,459	7,572,750	7,690,041	7,807,331	7,924,622	8,041,912	8,159,203	8,159,203
End Of Month Rate Base	66,463,310	66,558,103	66,560,976	66,604,906	66,669,946	66,930,142	67,336,383	68,107,252	70,962,749	71,700,328	72,251,553	72,752,068	72,752,068
Average Rate Base (Prior Mo + Cur Month/2)	66,285,118	66,510,707	66,559,539	66,582,941	66,637,426	66,800,044	67,133,263	67,721,818	69,535,000	71,331,538	71,975,940	72,501,810	
Return on Rate Base													
Debt Return (Avg RB * Wtd Cost of Debt)	125,389	125,816	125,908	125,953	126,056	126,363	126,994	128,107	131,537	134,935	136,154	137,149	1,550,363
Equity Return (Avg RB * Wtd Cost of Equity)	289,997	290,984	291,198	291,300	291,539	292,250	293,708	296,283	304,216	312,075	314,895	317,195	3,585,641
Total Return on Rate Base	415,387	416,800	417,106	417,253	417,595	418,614	420,702	424,390	435,753	447,011	451,049	454,345	5,136,004
Income Statement Items													
AFUDC Pre-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-
Property Taxes	96,630	96,630	96,630	96,630	96,630	96,630	96,630	96,630	96,630	96,630	96,630	96,630	1,159,565
Book Depreciation	136,184	136,693	137,028	137,352	137,726	138,239	138,966	140,010	143,459	146,891	148,017	148,934	1,689,498
Deferred Taxes	117,291	117,291	117,291	117,291	117,291	117,291	117,291	117,291	117,291	117,291	117,291	117,291	1,407,487
Gross Up for Income Tax (see below)	99,219	99,653	98,151	85,781	86,856	80,186	77,797	72,521	77,465	104,866	116,606	120,808	1,119,908
Total Income Statement Expense	449,324	450,266	449,099	437,054	438,503	432,347	430,684	426,452	434,845	465,678	478,544	483,663	5,376,458
Total Revenue Requirement	**864,711**	**867,067**	**866,206**	**854,307**	**856,098**	**850,960**	**851,385**	**850,842**	**870,598**	**912,689**	**929,593**	**938,007**	**10,512,463**
Capital Structure													
Weighted Cost of Debt	2.27%												
Weighted Cost of Equity	5.25%												
Required Rate of Return	7.52%												
Current Income Tax Calculation													
Equity Return	289,997	290,984	291,198	291,300	291,539	292,250	293,708	296,283	304,216	312,075	314,895	317,195	3,585,641
Book Depreciation	136,184	136,693	137,028	137,352	137,726	138,239	138,966	140,010	143,459	146,891	148,017	148,934	1,689,498
Deferred Taxes	117,291	117,291	117,291	117,291	117,291	117,291	117,291	117,291	117,291	117,291	117,291	117,291	1,407,487
Less Tax Depreciation	405,470	405,470	407,782	426,180	426,180	438,102	444,989	457,815	461,102	430,844	417,702	414,448	5,136,086
Plus CPI-Tax Interest (If Applicable)	2,612	1,731	1,366	1,806	2,718	3,963	5,280	7,009	5,923	3,204	2,754	2,238	40,605
Total	140,614	141,229	139,100	121,569	123,094	113,641	110,255	102,777	109,785	148,618	165,255	171,210	1,587,146
Tax Rate (T/(1-T)	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611
Gross Up for Income Tax	99,219	99,653	98,151	85,781	86,856	80,186	77,797	72,521	77,465	104,866	116,606	120,808	1,119,908

Northern States Power Company

TIMP - Capital Revenue Requirements	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Total
Rate Base													
CWIP	-	-	-	-	-	-	-	-	-	-	-	-	-
Plant In-Service	77,943,161	78,357,327	78,891,953	79,891,266	81,123,838	83,184,433	85,707,214	89,809,399	94,030,698	98,019,039	101,406,402	104,217,957	104,217,957
Less Accumulated Book Depreciation Reserve	(3,323,462)	(3,186,112)	(3,052,130)	(2,928,230)	(2,808,434)	(2,707,265)	(2,617,083)	(2,559,876)	(2,500,830)	(2,430,454)	(2,337,160)	(2,224,397)	(2,224,397)
Less Accumulated Deferred Taxes	8,329,445	8,499,688	8,669,930	8,840,173	9,010,415	9,180,658	9,350,900	9,521,143	9,691,385	9,861,627	10,031,870	10,202,112	10,202,112
End Of Month Rate Base	72,937,178	73,043,752	73,274,152	73,979,322	74,921,857	76,711,041	78,973,397	82,848,132	86,840,143	90,587,865	93,711,692	96,240,242	96,240,242
Average Rate Base (Prior Mo + Cur Month/2)	72,844,623	72,990,465	73,158,952	73,626,737	74,450,590	75,816,449	77,842,219	80,910,765	84,844,138	88,714,004	92,149,778	94,975,967	
Return on Rate Base													
Debt Return (Avg RB * Wtd Cost of Debt)	137,798	138,074	138,392	139,277	140,836	143,419	147,252	153,056	160,497	167,817	174,317	179,663	1,820,398
Equity Return (Avg RB * Wtd Cost of Equity)	318,695	319,333	320,070	322,117	325,721	331,697	340,560	353,985	371,193	388,124	403,155	415,520	4,210,171
Total Return on Rate Base	456,493	457,407	458,463	461,394	466,557	475,116	487,811	507,041	531,690	555,941	577,472	595,183	6,030,568
Income Statement Items													
AFUDC Pre-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-
Property Taxes	109,704	109,704	109,704	109,704	109,704	109,704	109,704	109,704	109,704	109,704	109,704	109,704	1,316,453
Book Depreciation	149,658	150,236	150,842	151,822	153,248	155,352	158,280	162,512	167,830	173,075	177,787	181,747	1,932,387
Deferred Taxes	170,242	170,242	170,242	170,242	170,242	170,242	170,242	170,242	170,242	170,242	170,242	170,242	2,042,909
Gross Up for Income Tax (see below)	79,173	79,786	74,018	64,194	68,493	50,364	55,085	27,773	66,475	92,882	127,054	146,199	931,497
Total Income Statement Expense	508,778	509,969	504,807	495,962	501,688	485,663	493,312	470,232	514,251	545,904	584,788	607,893	6,223,247
Total Revenue Requirement	**965,271**	**967,376**	**963,270**	**957,357**	**968,245**	**960,779**	**981,123**	**977,273**	**1,045,941**	**1,101,845**	**1,162,260**	**1,203,076**	**12,253,815**
Capital Structure													
Weighted Cost of Debt	2.27%												
Weighted Cost of Equity	5.25%												
Required Rate of Return	7.52%												
Current Income Tax Calculation													
Equity Return	318,695	319,333	320,070	322,117	325,721	331,697	340,560	353,985	371,193	388,124	403,155	415,520	4,210,171
Book Depreciation	149,658	150,236	150,842	151,822	153,248	155,352	158,280	162,512	167,830	173,075	177,787	181,747	1,932,387
Deferred Taxes	170,242	170,242	170,242	170,242	170,242	170,242	170,242	170,242	170,242	170,242	170,242	170,242	2,042,909
Less Tax Depreciation	528,241	528,241	537,947	556,097	556,097	592,027	599,127	659,627	629,377	613,727	583,401	570,591	6,954,501
Plus CPI-Tax Interest (If Applicable)	1,850	1,503	1,692	2,892	3,955	6,113	8,113	12,248	14,320	13,920	12,278	10,276	89,161
Total	112,205	113,074	104,900	90,976	97,069	71,377	78,068	39,360	94,209	131,634	180,062	207,195	1,320,128
Tax Rate (T/(1-T)	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611
Gross Up for Income Tax	79,173	79,786	74,018	64,194	68,493	50,364	55,085	27,773	66,475	92,882	127,054	146,199	931,497

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Xcel Energy
Docket No.: G002/M-17-787
Response To: MN Department of Commerce Information Request No. 41
Requestors: Dorothy Morrissey, Danielle Winner
Date Received: March 27, 2018

Question:

Topic: TIMP revenue requirements – Accumulated Depreciation
Reference(s): Attachment F

A. Pages 3: Please explain the reason the monthly Accumulated Depreciation reserve balance in 2018 has a debit balance.

B. Pages 2-3: Please provide a detailed explanation of the monthly change in the Accumulated Depreciation reserve balance for each month from August 2017 to December 2018.

Response:

A. Accumulated depreciation reserve balance in 2018 had a debit balance due to the closing of removal work in progress (RWIP) expenditures, resulting from RWIP closings being greater than the accumulated reserve balance for current GUIC projects. RWIP closings decrease the balance of accumulated depreciation, because an estimated cost of removal amount is factored in to the depreciation rate approved by the Commission in order to collect the cost to remove an asset while that asset is in service through depreciation.

B. Please see Attachment A to this response, which provides an accumulated depreciation reserve balance rollforward for the periods of August 2017 to December 2018. The rollforward shows the monthly book depreciation expense, which increases the accumulated depreciation reserve balance, along with the monthly RWIP closings, which decreases the balance.

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Department: Revenue Requirements – North
Telephone: 612-337-2076
Date: April 6, 2018

Northern States Power Company

TIMP	Aug - 2017	Sep - 2017	Oct - 2017	Nov - 2017	Dec - 2017	Jan - 2018	Feb - 2018	Mar - 2018	Apr - 2018	May - 2018	Jun - 2018	Jul - 2018	Aug - 2018	Sep - 2018	Oct - 2018	Nov - 2018	Dec - 2018
Accumulated Reserve Beginning Balance	1,796,636	1,915,747	(2,703,454)	(4,096,618)	(4,529,778)	(4,636,295)	(4,609,154)	(4,525,570)	(4,417,708)	(4,299,168)	(4,175,772)	(4,055,584)	(3,939,973)	(3,832,383)	(3,722,671)	(3,607,184)	(3,482,830)
Book Depreciation	123,037	124,815	127,785	130,463	133,844	136,184	136,693	137,028	137,352	137,726	138,239	138,966	140,010	143,459	146,891	148,017	148,934
Closings - Removal	(3,926)	(4,744,015)	(1,520,950)	(563,622)	(240,361)	(109,043)	(53,109)	(29,166)	(18,811)	(14,330)	(18,051)	(23,355)	(32,420)	(33,746)	(31,405)	(23,663)	(124,577)
Accumulated Reserve Ending Balance	1,915,747	(2,703,454)	(4,096,618)	(4,529,778)	(4,636,295)	(4,609,154)	(4,525,570)	(4,417,708)	(4,299,168)	(4,175,772)	(4,055,584)	(3,939,973)	(3,832,383)	(3,722,671)	(3,607,184)	(3,482,830)	(3,458,473)

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Xcel Energy
Docket No.: G002/M-17-787
Response To: MN Department of Commerce Information Request No. 8
Requestors: Dorothy Morrissey, Danielle Winner
Date Received: January 24, 2018

Question:

Topic: DIMP; Plant Replacements
Reference(s): Initial filing, p. 29

A. Please identify and quantify the distribution-plant 2010 test-year costs that were included in base rates (GR-09-1153) and have since been replaced under GUIC. Identify where in the GUIC filing these 2010 test-year base rate costs have been reflected as an adjustment to the GUIC revenue requirement request.

B. Please identify the 2010 test-year costs tied to the distribution plant included in base rates that are earmarked to be replaced in 2018 and included in GUIC. Identify wherein the GUIC filing these 2010 test-year base rate costs have been reflected as an adjustment to the GUIC revenue requirement request.

Response:

A. We are unable to identify and quantify the specific distribution plant assets replaced as a part of the GUIC project. This is due to the fact the assets that are retired from our accounting records are determined using an automated statistical process within our asset accounting system.

The Company accounts for its gas distribution assets using the group accounting method. This primarily means that all assets are grouped together and depreciated as a whole, rather than as individual assets. When a retirement occurs, an automated statistical model analysis is performed by our asset accounting system. The statistical analysis is based on retirement and survivor curves derived from actuarial modeling of the historical addition and retirement data of our assets. The proper curves, based on the industry-accepted Iowa Curves, for each type of asset are assessed and approved by the Commission every five years as a part of our depreciation filings for transmission, distribution, and general assets.

A retirement curve plots the percentage of a similarly-aged group of assets that would normally be expected to be retired in any given year. For example, a retirement curve may estimate that 20 percent of assets would be expected to be retired after 20 years of life. Conversely, the survivor curve plots the percentage of a similarly-aged group of assets that would be expected to survive in any given year. The curve may state that we expect 99 percent of a group of assets to survive 1 year, 50 percent to survive 25 years, and 1 percent to survive 60 years. These curves are based on the same actuarial analysis and provide two views of the same expected pattern of life and death of a group of assets. Using the curves, the most likely vintage of asset to be retired can be determined and removed from our asset records.

As an example of how the retirement process using curves works, assume the Company is replacing 1,000 feet of main as a part of a DIMP project. At completion, the specific 1,000 feet of pipe being replaced would not specifically be removed from our accounting system. Rather, the most appropriate vintage of pipe to retire is determined using the approved curves. 1,000 feet of pipe of that appropriate vintage is identified, and that segment of pipe is retired from the system. This is an automatic process built into our asset accounting system. When new assets are being added to replace old assets, a direct link is not made between the new asset and the asset that was being retired from our asset records.

Even without having an asset-specific retirement process, the net result in our asset records is the same. The proper quantity, whether feet for mains or a count for services, is removed from our property records, along with the corresponding capitalized asset value. All assets, regardless of age, are retired at a net book value of zero. The amount of accumulated depreciation retired is the same as the capitalized asset value retired.

While we cannot identify the specific assets that were replaced during our DIMP projects, we have an idea of the vintages of pipe that was replaced. Attachment A to this response provides a listing of replacement projects either completed, or expected to be completed from 2015 through 2017. The listing of projects (without replaced asset vintage detail) was previously provided as Attachments C1(b), C1(c), and C1(d) in our 2017 GUIC Rider Filing (Docket No. G002/M-16-891). The schedule shows both mains and services replaced. For the distribution mains, the vintage of pipe replaced is provided, if that information is known. The information is more difficult to gather for services. Each service replaced has its own record stating its installation vintage. With thousands of services replaced each year, knowing the vintage of services replaced would require manually reviewing thousands of records. Many services are of similar vintages as the mains they are connected to, but service relocations and damaged service replace will cause services to be replaced independent of a main replacement.

As shown in Attachment A, the mains that were replaced were relatively old. Based on the 45-year average service life approved for depreciation distribution mains in the 2010 rate case (as shown in our response to Department Information Request No. 4), a large portion of these would have either been fully depreciated, or close to fully depreciated at the time of the last rate case. Even though we cannot specifically quantify the amount of installed value of the mains replaced in the DIMP projects, we can confidently say that in the rate base of the last gas rate case, the replaced assets would have had a net book value far lower than their initial capitalized value. Services had an approved average service life of 40 years at the same time period.

B. The 2018 information included in our current GUIC filing is all forecast-based information. When preparing capital forecasts for distribution assets, the Company does not plan the retirement of specific assets. Rather, forecasted retirement percentages are applied to beginning plant balances, and that amount is retired monthly throughout the entire forecast period. The forecast retirement percentages are based on a five-year average of historical retirements. The amount of retirements is calculated and removed from the forecasted plant balance, but those retirements are not assigned to specific assets. As such, the Company cannot identify specific distribution assets slated to be retired as a part of the planned 2018 GUIC projects.

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NSP-MN Main & Services DIMP Replacements					Main Footage			Service		
Division	Project	WO	Year Retired Main was Installed	Remaining Depreciable Service Life 1/1/2010 [1]	Estimate	Actual Replaced	Actual Installed from Passport	Estimate	Replaced	Transferred
St Paul	STP/ARLINGTON, NEVADA, NEBRASKA BTN. WHITE BEAR & FURNESS	11935351	1977	12	12,760	7,100	12,760	230	223	4
	ROSEVILLE/ COHANSEY ST. PROJECT/ INSTALL 7500' OF 2" PE	12118923	1965	0	7,500	4,530	7,517	74	71	2
	STP / CLARENCE ST BTN ARLINGTON AVE E & HOYT AVE E / DIMP PR	12096468	1967	2	2,600	1,300	1,300	48	46	4
	Barclay/Dieter	12185039	Unknown	-	3,750	2,675	3,925	60	58	4
	STP / IVY AVE E XST: RUTH ST / LOW PRESSURE DIMP PROJECT	12088590	1953	0	16,000	11,350	16,031	218	224	0
	STP / 7TH ST W BTN ALTON & RANKIN ST	12217850	1972	7	2,326	4,660	2,326	24	21	4
	Idaho / Barclay / Clarence	12227467	1960	0	7,350	4,775	7,467	99	93	8
	ROSEVILLE/ GALTIER ST/ INSTALL 4600' OF 2" PE MAIN (DIMP)	12122749	Unknown	-	4,400	2,405	4,560	49	48	0
White Bear Lake	VADNAIS HEIGHTS-5-STAR MOBILE ESTATES-INSTALL 10,480' 2" PE	12100647	1974	9	10,480	9,225	10,124	190	112	77
	LAKE ELMO-CIMARRON MOBILE HOME PARK-SOUTH HALF-RENEW MAIN	12148971	1970	5	15,000	15,234	15,234	250	228	0
	LAKE ELMO-CIMARRON MOBILE HOME PARK-NORTH HALF-RENEW MAIN*	12225339	1970	5	16,709	16,064	16,709	252	237	0
	WBL/OPH/Area D	12200298	1962	0	5,000	4,520	5,097	12	14	7
	Vad Heights - North Star Estates	12226824	1972	7	10,000	7,040	9,485	172	161	8
	BAYPORT 5TH ST S INSTALL 3900' OF 2"PE MAIN RENEW 43 SVCS	12093773	Unknown	-	2,900	2,000	3,845	43	16	23
	NO ST PAUL / 14th AVE E	11945105	1978	13	3,865	2,105	3,999	48	40	6
Wyoming	Forest Lake - Carry-over from 2014	12185020	1968	3	9,000	10,850	8,741	93	68	28
	Forest Lake - 11th Ave & 6th St	12233388	1968	3	4,100	3,310	3,310	36	41	6
	Forest Lake - 1st Ave / 2nd Ave / 8th St / 7th St / 6th St	12234310	Unknown	-	4,650	3,750	4,642	27	43	9
Newport	Cloman Way & Lower 67th St	12262781	1971	6	5,500	3,900	6,322	152	154	0
	ST PAUL PARK /2015 DIMP/ DIXON / BLOSSOM	12148969	Unknown	-	2,204	950	2,224	26	26	0
	2015 DIMP / ST PAUL PK / DIXON DR	12149144	Unknown	-	2,581	1,600	2,549	29	29	0
	2015 DIMP / ST PAUL PK / GARY/ SELBY / DAYTON	12149707	Unknown	-	9,274	5,050	9,274	110	110	0
	ST PAUL PARK / 2015 DIMP / PORTLAND AVE / 13TH / 15TH	12101212	1972	7	1,800	1,240	1,764	16	11	5
	SOUTH ST PAUL / 2015 DIMP / BUTLER / KASSAN	12089427	1974	9	2,224	2,980	2,224	20	15	3
	SOUTH ST PAUL / 2015 DIMP BUTLER AVE / BUTLER CT	12101218	1974	9	2,298	1,200	2,298	30	26	6
	Denton	12255539	1973	8	4,828	4,220	4,828	75	75	0
	Burns Ave	12170859	Unknown	-	6,901	3,900	6,902	85	73	11
St Cloud	DLH / DIMP / RIVER'S EDGE PARKING	12188957	Unknown	-	250	256	270	2	0	0
	St Cloud - Lincoln Ave*	12223516	Unknown	-	7,750	5,990	6,273	36	18	11
	Watertown	12162124	Unknown	-	10,200	7,030	10,210	95	73	37
	Sauk Rapids - 7th St NE (@ 2nd Ave NE)	12227154	Unknown	-	286	250	250	3	3	0
Southeast	GOODVIEW-LAKE VILLAGE MOBILE HOME PARK	12157111	1974	9	9,989	6,930	8,455	230	192	0
	Northfield Viking Ter	12241776	1970	5	10,550	8,525	7,677	180	180	0
	7th St S - Lake City	12205025	1971	6	1,400	-	1,256	6	0	0
	Hallstrom Dr & Burton St - Red Wing	12218584	1971	6	17,000	14,482	14,482	270	136	25
	Bluffview - Winona	12231997	1971	6	2,000	1,120	1,626	5	12	3
	Bush St & Langsford Ave - Red Wing	12212950	1972	7	5,950	5,100	6,337	85	69	7
	Hillsdale - Hidden Valley Mobile Home Park	12162836	1976	11	10,064	8,115	10,699	185	176	0
Moorhead	Moorehead 30th Ave & 8th St S	12215066 & 12208317	Unknown	-	975	-		1	0	0
	Moorehead Dale & 5th St S	12215099 & 12210767	Unknown	-	1,608	-	1,599	32	0	0
	Service Materials									
		Totals			254,022	195,731	244,591	3,598	3,122	298

[1] Remaining Service Life at start of 2010 Test Year in 2010 Gas Rate Case (G002/GR-09-1153). Based on Gas Distribution Main Depreciation Average Service Life of 45 Years (Approved in E,G002/D-07-1528)

NSP-MN Main & Services DIMP Replacement Projects 2016

Area	Work Order Number	Description	Year Retired Main was Installed	Remaining Depreciable Service Life 1/1/2010 [1]	Total Design FT.	Tot. Svc
St Paul	12092489	ST PAUL - ARMSTRONG AVE XST: CHATSWORTH ST S	1990	25	1,350	28
	12328949	ST PAUL - ARMSTRONG AVE	1990	25	7,506	150
	12381180	ST PAUL - ATLANTIC, DULUTH & LARPENTEUR	1955	0	8,900	118
	12294860	ROSEVILLE - GLENHILL, WOODLYNN, CLARMAR	1955	0	7,810	81
	12398688	LAUDERDALE - EUSTIS ST	Unknown	-	1,100	17
	12380740	ROSEVILLE - WEWERS RD	Unknown	-	1,400	15
	12404989	ST PAUL - DOWNTOWN - 10TH-MINNESOTA	1957	0	1,200	5
	12344852	ROSEVILLE - COUNTY RD C, FISK, AVON, GROTTO	1958	0	23,400	305
	12444470	ST PAUL - DOWN TOWN (Kellogg)	1956	0	150	-
	12361662	ST PAUL - JUNO CONTRACTOR PORTION	1980	15	4,750	56
	12358730	ST PAUL - JUNO LOCAL PORTION	1980	15	1,260	20
	12364882	ST PAUL - AURORA - LOCAL PORTION	1980	15	960	36
	12369728	ST PAUL - AURORA - CONTRACTOR PORTION	1980	15	3,875	100
	12317526	ST PAUL - BERKELY-STANFORD-WELLESLY	1980	15	10,440	195
	12294862	ROSEVILLE - SKILLMAN-ELDRIDGE	1963	0	6,700	79
White Bear Lake	12344860	LAKE ELMO - 32ND ST	Unknown	-	8,600	77
	12293638	LAKE ELMO - LAKE ELMO AVE	Unknown	-	6,800	51
	12334697	NORTH ST PAUL - 19TH AVE	1956	0	7,000	85
	12371725	BAYTOWN TWP/ 13606 30TH ST N	Unknown	-	320	5
	12320156	OAKDALE - GROSPOINT AVE	1960	0	16,200	178
	12317855	WHITE BEAR LAKE - FLORENCE ST	1976	11	16,600	109
	12320058	MAPLEWOOD - ROSELAWN AVE	1954	0	12,900	179
	12320143	OAKDALE - GERSHWIN AVE	1967	2	9,500	70
	12320392	SHOREVIEW - DEBRA LN	1976	11	11,200	105
	12317856	SHOREVIEW - NANCY PL	1971	6	7,600	85
	12275730	OAKDALE - GREENE AVE	Unknown	-	2,150	22
Wyoming	12334677	FOREST LAKE - 2ND ST SE	1972	7	10,900	128
Newport	12346387	SOUTH ST PAUL - 3RD AVE S - 6TH ST S	Unknown	-	1,680	28
	12352620	MENDOTA HTS - 3RD ST-VANDALL-SOMERSET	1968	3	1,900	22
	12352631	ST PAUL PARK - 13TH-14TH-CHICAGO	Unknown	-	8,815	100
	12346491	SOUTH ST PAUL - 2ND AVE S - MARIE AVE	Unknown	-	7,530	120
	12346357	MENDOTA HTS - HWY 13 - WACHTER AVE	Unknown	-	911	5
St Cloud	12342575	ST JOSEPH - 1ST AVE NE - CTY RD 75	1966	1	9,150	79
	12403875	SARTELL - MISSISSIPPI RIVER CROSSING	1973	8	1,700	-
	12249351	DELANO	Unknown	-	14,800	127
Southeast	12385504	WINONA - 3RD ST BTW GALE ST-MECHANIC ST	1974	9	8,100	127
	12354151	NORTHFIELD - FLORELLAS CT	1968	3	1,550	22
	12328936	FARIBAULT - 8TH ST SW	Unknown	-	5,320	48
	12345274	FARIBAULT - 7TH ST NW	1980	15	4,900	43
	12350531	FARIBAULT - 8TH ST SW, BOTSFORD, CARLTON	Unknown	-	3,000	49
Moorhead	12359542	MOORHEAD - REGAL ESTATES	Unknown	-	10,500	210
2016 DIMP-related Main Replacement Total					**270,427**	**3,279**

[1] Remaining Service Life at start of 2010 Test Year in 2010 Gas Rate Case (G002/GR-09-1153). Based on Gas Distribution Main Depreciation Average Service Life of 45 Years (Approved in E,G002/D-07-1528)

NSP-MN Main & Services DIMP Replacement Projects 2017

Area	Work Order Number	Description	Year Retired Main was Installed	Remaining Depreciable Service Life 1/1/2010 [1]	Total Design FT.
St Paul	12294045	ROSEVILLE - FERNWOOD ST	1955	0	3,760
	12315892	ST PAUL - CASE AVE BTN EDGERTON-EARL	1979	14	11,300
	12328310	ST PAUL - HAGUE/SELBY	1978	13	6,745
	12326608	ST PAUL - EDMOND	Unknown	-	5,290
	N/A	ST PAUL - ST PETER, FORD 4TH	1963	0	4,200
	12320752	ST PAUL - ETNA-BIRMINGHAM-WINCHELL	1962	0	9,600
White Bear Lake	12317581	ARDEN HILLS - ARDEN VIEW DR	Unknown	-	2,300
	12320389	ARDEN HILLS - GLENPAUL AVE	1955	0	4,700
	12319969	MAHTOMEDI - GRIFFIN AVE	1968	3	3,200
	12092590	BAYPORT - 7TH ST	1964	0	1,000
Wyoming	12320014	FOREST LAKE - 11TH AVE SW (LAKE ST)	Unknown	-	2,100
	12320051	FOREST LAKE - 208TH-209TH ST	1969	4	4,000
	12320027	FOREST LAKE - IVERSON AVE	1967	2	3,700
	N/A	FOREST LAKE - HEATH AVE	1968	3	3,600
Newport	12352434	COTTAGE GROVE - IRONWOOD	1971	6	3,338
	12438126	ST PAUL - BURNS-RUTH	1955	0	11,715
	DE 522036	COTTAGE GROVE - HYDE	1961	0	3,710
	DE 521888	COTTAGE GROVE - PT DOUGLAS RD, IDEAL AVE	1961	0	4,735
	DE 521609	COTTAGE GROVE - IDEAL-85TH ST	1962	0	4,160
	DE 521021	MENDOTA HTS - BACHELOR-SUTTON-MARIE	1973	8	10,570
	DE 526906	INVER GROVE HTS - DAWN-UPPER 75TH-77TH	1971	6	5,160
	DE 519457	INVER GROVE HTS - CONROY CT	1972	7	5,400
St Cloud	N/A	ST CLOUD - 16TH AVE - 3RD ST N	1972	7	4,100
	12412846	ST CLOUD - 44TH AVE N, APPOLLO BY VA	1972	7	2,500
Southeast	DE 525652	WINONA - 3RD ST BTW WINONA ST-LIBERTY ST	1968	3	8,500
	12320940	NORTHFIELD - WOODLEY ST E	1977	12	500
	12344771	NORTHFIELD - ARCHIBALD ST/ASTER	1981	16	3,500
	12356426	LAKE CITY - LAKEWOOD AVE	1972	7	4,250
	12360394	RED WING - SPRUCE/SOUTHWOOD	Unknown	-	6,000
	12356414	WINONA - 9TH/52ND	1977	12	3,500
	N/A	NORTHFIELD - EDWARDS LN	1968	3	1,660
	DE 525650	RED WING - BUSH ST - PLUM ST	1983	18	3,250
	N/A	RED WING - WRIGHT/FINRUD	1975	10	10,400
Moorhead	12410474	MOORHEAD-MOBILE MANOR-1224 15TH AVE. N	1972	7	1,260
	12422040	DILWORTH - 1ST AVE SE	1972	7	5,000
2017 Designed DIMP-related Main Replacement Total					**168,703**

[1] Remaining Service Life at start of 2010 Test Year in 2010 Gas Rate Case (G002/GR-09-1153). Based on Gas Distribution Main Depreciation Average Service Life of 45 Years (Approved in E,G002/D-07-1528)

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Xcel Energy
Docket No.: G002/M-17-787
Response To: MN Department of Commerce Information Request No. 44
Requestor: Dorothy Morrissey, Danielle Winner
Date Received: March 29, 2018

Question:

Topic: Revenue Requirement Category Descriptions – DIMP Book Depreciation
Reference(s): Attachment P, p. 2, Attachment K and Attachment G

Attachment K presents the Book Depreciation rate for distribution is 2.52 percent. Please provide in a live spreadsheet with formulae intact, each of the following:

A. the calculation of the monthly depreciation amount, including the depreciation rate used, for the 2016 book depreciation amounts reported in Attachment G, page 1, for each of the months May 2016 through December 2016; Please explain any discrepancies between depreciation rate used and the Attachment K stated rates;

B. the calculation of the monthly depreciation amount reported in Attachment G, page 2, including the depreciation rate used, for each of the months in 2017; Please explain any discrepancies between depreciation rate used and the Attachment K stated rates;

C. the calculation of the monthly depreciation amount reported in Attachment G, page 3, including the depreciation rate used, for each of the months in 2018; Please explain any discrepancies between depreciation rate used and the Attachment K stated rates.

Response:

A. The total 2016 DIMP book depreciation amount of $617,899 is comprised of both distribution and software projects, which utilize different depreciation rates. Please see Attachment A to this response for the calculation of 2016 monthly depreciation amounts. Attachment A is provided in live Excel spreadsheet format to show the exact calculations with the monthly book depreciation agreeing to Attachment G, page 1 filed with our original Petition.

B. The total 2017 DIMP book depreciation amount of $1,122,399 is comprised of both distribution and software projects, which utilize different depreciation rates. Please see Attachment A to this response for the calculation of 2017 monthly depreciation amounts, which agrees to the numbers shown in Petition Attachment G, page 2.

C. The total 2018 DIMP book depreciation amount of $1,639,514 is comprised of both distribution and software projects, which utilize different depreciation rates. Please see Attachment A to this response for the calculation of 2018 monthly depreciation amounts, which agrees to the numbers shown in Petition Attachment G, page 3.

Preparer:	Ryan Cummings
Title:	Senior Financial Analyst
Department:	Revenue Analysis
Telephone:	612-330-1958
Date:	April 9, 2018

	Jan - 2016	Feb - 2016	Mar - 2016	Apr - 2016	May - 2016	Jun - 2016	Jul - 2016	Aug - 2016	Sep - 2016	Oct - 2016	Nov - 2016	Dec - 2016	Total
DIMP Depreciation													
Distribution													
Book Plant End Bal	11,591,891	11,546,320	11,589,091	11,749,440	12,241,642	12,261,514	12,492,320	13,376,189	14,023,043	19,401,948	22,695,413	22,829,753	22,829,753
Previous Book Plant End Bal	11,201,196	11,591,891	11,546,320	11,589,091	11,749,440	12,241,642	12,261,514	12,492,320	13,376,189	14,023,043	19,401,948	22,695,413	
Annual Distribution Depreciation Rate (Att. K)	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	
Monthly Distribution Depreciation Rate	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	2.52%
DIMP Distribution Book Depreciation	23,933	24,295	24,292	24,505	25,191	25,728	25,992	27,162	28,769	35,096	44,202	47,801	356,967
Software													
Book Plant End Bal					2,087,278	2,087,485	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483
Previous Book Plant End Bal						2,087,278	2,087,485	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	
Annual Software Depreciation Rate (Att. K)	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	
Monthly Software Depreciation Rate	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	20.00%
DIMP Software Book Depreciation					17,394	34,790	34,791	34,791	34,791	34,791	34,791	34,791	260,932
Total DIMP Book Depreciation (Att. G)	23,933	24,295	24,292	24,505	42,585	60,518	60,783	61,953	63,561	69,888	78,994	82,593	617,899

	Jan - 2017	Feb - 2017	Mar - 2017	Apr - 2017	May - 2017	Jun - 2017	Jul - 2017	Aug - 2017	Sep - 2017	Oct - 2017	Nov - 2017	Dec - 2017	Total
DIMP Depreciation													
Distribution													
Book Plant End Bal	24,092,041	24,084,057	23,935,755	24,112,772	25,341,828	26,558,953	27,594,739	29,004,650	32,008,551	33,940,860	35,422,537	36,312,416	36,312,416
Previous Book Plant End Bal	22,829,753	24,092,041	24,084,057	23,935,755	24,112,772	25,341,828	26,558,953	27,594,739	29,004,650	32,008,551	33,940,860	35,422,537	
Annual Distribution Depreciation Rate (Att. K)	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	
Monthly Distribution Depreciation Rate	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	2.52%
DIMP Distribution Book Depreciation	49,268	50,585	50,421	50,451	51,927	54,496	56,861	59,429	64,064	69,247	72,832	75,322	704,902
Software													
Book Plant End Bal	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483
Previous Book Plant End Bal	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	
Annual Software Depreciation Rate (Att. K)	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	
Monthly Software Depreciation Rate	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	20.00%
DIMP Software Book Depreciation	34,791	34,791	34,791	34,791	34,791	34,791	34,791	34,791	34,791	34,791	34,791	34,791	417,497
Total DIMP Book Depreciation (Att. G)	84,059	85,376	85,212	85,242	86,719	89,287	91,653	94,221	98,855	104,038	107,623	110,113	1,122,399

	Jan - 2018	Feb - 2018	Mar - 2018	Apr - 2018	May - 2018	Jun - 2018	Jul - 2018	Aug - 2018	Sep - 2018	Oct - 2018	Nov - 2018	Dec - 2018	Total
DIMP Depreciation													
Distribution													
Book Plant End Bal	36,782,087	37,292,616	37,790,888	38,747,108	41,049,288	44,302,838	47,713,176	53,137,413	58,407,873	64,009,550	68,806,998	71,434,093	71,434,093
Previous Book Plant End Bal	36,312,416	36,782,087	37,292,616	37,790,888	38,747,108	41,049,288	44,302,838	47,713,176	53,137,413	58,407,873	64,009,550	68,806,998	
Annual Distribution Depreciation Rate (Att. K)	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	
Monthly Distribution Depreciation Rate	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	2.52%
DIMP Distribution Book Depreciation	76,749	77,778	78,838	80,365	83,786	89,620	96,617	105,893	117,123	128,538	139,457	147,253	1,222,017
Software													
Book Plant End Bal	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483
Previous Book Plant End Bal	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	2,087,483	
Annual Software Depreciation Rate (Att. K)	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	
Monthly Software Depreciation Rate	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	20.00%
DIMP Software Book Depreciation	34,791	34,791	34,791	34,791	34,791	34,791	34,791	34,791	34,791	34,791	34,791	34,791	417,497
Total DIMP Book Depreciation (Att. G)	111,541	112,570	113,629	115,156	118,578	124,411	131,408	140,684	151,914	163,330	174,249	182,045	1,639,514

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Xcel Energy
Docket No.: G002/M-17-787
Response To: MN Department of Commerce Information Request No. 45
Requestor: Dorothy Morrissey, Danielle Winner
Date Received: March 29, 2018

Question:

Topic: Revenue Requirement Category Descriptions – TIMP Book Depreciation
Reference(s): Attachment P, p. 2, Attachment K and Attachment F

Attachment K presents the Book Depreciation rate for transmission is 1.53 percent. Please provide in a live spreadsheet with formulae intact, each of the following:

A. the calculation of the monthly depreciation amount, including the depreciation rate used, for the 2016 book depreciation amounts reported in Attachment F, page 1, for each of the months in 2016; Please explain any discrepancies between depreciation rate used and the Attachment K stated rates;

B. the calculation of the monthly depreciation amount reported in Attachment F, page 2, including the depreciation rate used, for each of the months in 2017; Please explain any discrepancies between depreciation rate used and the Attachment K stated rates;

C. the calculation of the monthly depreciation amount reported in Attachment F, page 3, including the depreciation rate used, for each of the months in 2018; Please explain any discrepancies between depreciation rate used and the Attachment K stated rates.

Response:

A. The total 2016 TIMP book depreciation amount of $1,177,163 is comprised of both distribution and transmission projects, which utilize different depreciation rates. Please see Attachment A to this response for the calculation of 2016 monthly depreciation amounts. Attachment A is provided in live Excel spreadsheet format to show the exact calculations with the monthly book depreciation agreeing to Attachment F, page 1 filed with our original Petition.

B. The total 2017 TIMP book depreciation amount of $1,490,106 is comprised of both distribution and transmission projects, which utilize different depreciation rates. Please see Attachment A to this response for the calculation of 2017 monthly depreciation amounts, which agrees to the numbers shown in Petition Attachment F, page 2.

C. The total 2018 TIMP book depreciation amount of $1,689,498 is comprised of both distribution and transmission projects, which utilize different depreciation rates. Please see Attachment A to this response for the calculation of 2018 monthly depreciation amounts, which agrees to the numbers shown in Petition Attachment F, page 3.

Preparer: Ryan Cummings
Title: Senior Financial Analyst
Department: Revenue Analysis
Telephone: 612-330-1958
Date: April 9, 2018

	Jan - 2016	Feb - 2016	Mar - 2016	Apr - 2016	May - 2016	Jun - 2016	Jul - 2016	Aug - 2016	Sep - 2016	Oct - 2016	Nov - 2016	Dec - 2016	Total
TIMP Depreciation													
Distribution													
Book Plant End Bal	39,738,259	39,959,403	39,954,187	40,089,383	40,091,429	47,376,740	45,781,626	51,402,464	53,435,658	51,257,659	53,893,255	54,494,240	54,494,240
Previous Book Plant End Bal	39,925,286	39,738,259	39,959,403	39,954,187	40,089,383	40,091,429	47,376,740	45,781,626	51,402,464	53,435,658	51,257,659	53,893,255	
Annual Distribution Depreciation Rate (Att. K)	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	
Monthly Distribution Depreciation Rate	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	2.52%
TIMP Distribution Book Depreciation	83,647	83,683	83,909	84,046	84,190	91,842	97,816	102,043	110,080	109,928	110,408	113,807	1,155,399
Transmission													
Book Plant End Bal	1,264,748	1,266,102	1,267,650	1,270,007	1,272,062	1,271,790	1,268,714	1,271,273	1,271,382	1,270,383	1,271,087	4,904,477	4,904,477
Previous Book Plant End Bal	1,232,467	1,264,748	1,266,102	1,267,650	1,270,007	1,272,062	1,271,790	1,268,714	1,271,273	1,271,382	1,270,383	1,271,087	
Annual Transmission Depreciation Rate (Att. K)	1.53%	1.53%	1.53%	1.53%	1.53%	1.53%	1.53%	1.53%	1.53%	1.53%	1.53%	1.53%	
Monthly Transmission Depreciation Rate	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	1.53%
TIMP Transmission Book Depreciation	1,595	1,617	1,619	1,621	1,624	1,625	1,623	1,623	1,624	1,624	1,624	3,945	21,765
Total TIMP Book Depreciation (Att. F)	85,242	85,299	85,528	85,667	85,814	93,467	99,439	103,666	111,704	111,552	112,032	117,752	1,177,163

	Jan - 2017	Feb - 2017	Mar - 2017	Apr - 2017	May - 2017	Jun - 2017	Jul - 2017	Aug - 2017	Sep - 2017	Oct - 2017	Nov - 2017	Dec - 2017	Total
TIMP Depreciation													
Distribution													
Book Plant End Bal	54,503,315	54,514,836	54,520,254	54,784,362	54,909,742	55,044,386	55,057,976	55,059,463	56,257,917	57,029,103	57,803,697	59,212,616	59,212,616
Previous Book Plant End Bal	54,494,240	54,503,315	54,514,836	54,520,254	54,784,362	54,909,742	55,044,386	55,057,976	55,059,463	56,257,917	57,029,103	57,803,697	
Annual Distribution Depreciation Rate (Att. K)	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	
Monthly Distribution Depreciation Rate	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	2.52%
TIMP Distribution Book Depreciation	114,447	114,469	114,487	114,770	115,179	115,452	115,607	115,623	116,883	118,951	120,574	122,867	1,399,311
Transmission													
Book Plant End Bal	4,902,622	4,977,396	4,979,997	4,986,591	5,238,399	5,416,341	5,705,829	5,898,250	6,516,540	7,310,610	8,167,063	9,013,997	9,013,997
Previous Book Plant End Bal	4,904,477	4,902,622	4,977,396	4,979,997	4,986,591	5,238,399	5,416,341	5,705,829	5,898,250	6,516,540	7,310,610	8,167,063	
Annual Transmission Depreciation Rate (Att. K)	1.53%	1.53%	1.53%	1.53%	1.53%	1.53%	1.53%	1.53%	1.53%	1.53%	1.53%	1.53%	
Monthly Transmission Depreciation Rate	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	1.53%
TIMP Transmission Book Depreciation	6,266	6,312	6,362	6,367	6,532	6,807	7,106	7,414	7,931	8,834	9,888	10,977	90,795
Total TIMP Book Depreciation (Att. F)	120,713	120,781	120,848	121,137	121,711	122,259	122,713	123,037	124,815	127,785	130,463	133,844	1,490,106

	Jan - 2018	Feb - 2018	Mar - 2018	Apr - 2018	May - 2018	Jun - 2018	Jul - 2018	Aug - 2018	Sep - 2018	Oct - 2018	Nov - 2018	Dec - 2018	Total
TIMP Depreciation													
Distribution													
Book Plant End Bal	59,212,616	59,212,616	59,212,616	59,212,616	59,212,616	59,212,616	59,212,616	59,212,616	61,263,212	61,263,212	61,263,212	61,263,212	61,263,212
Previous Book Plant End Bal	59,212,616	59,212,616	59,212,616	59,212,616	59,212,616	59,212,616	59,212,616	59,212,616	59,212,616	61,263,212	61,263,212	61,263,212	
Annual Distribution Depreciation Rate (Att. K)	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	2.52%	
Monthly Distribution Depreciation Rate	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	2.52%
TIMP Distribution Book Depreciation	124,346	124,346	124,346	124,346	124,346	124,346	124,346	124,346	126,500	128,653	128,653	128,653	1,507,230
Transmission													
Book Plant End Bal	9,514,813	9,810,480	10,038,505	10,318,267	10,623,994	11,121,668	11,760,810	12,756,560	13,788,464	14,758,820	15,551,689	16,193,852	16,193,852
Previous Book Plant End Bal	9,013,997	9,514,813	9,810,480	10,038,505	10,318,267	10,623,994	11,121,668	11,760,810	12,756,560	13,788,464	14,758,820	15,551,689	
Annual Transmission Depreciation Rate (Att. K)	1.53%	1.53%	1.53%	1.53%	1.53%	1.53%	1.53%	1.53%	1.53%	1.53%	1.53%	1.53%	
Monthly Transmission Depreciation Rate	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	1.53%
TIMP Transmission Book Depreciation	11,838	12,346	12,681	13,005	13,379	13,893	14,619	15,664	16,959	18,238	19,365	20,281	182,268
Total TIMP Book Depreciation (Att. F)	136,184	136,693	137,028	137,352	137,726	138,239	138,966	140,010	143,459	146,891	148,017	148,934	1,689,498

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Xcel Energy
Docket No.: G002/M-17-787
Response To: MN Department of Commerce Information Request No. 40
Requestors: Dorothy Morrissey, Danielle Winner
Date Received: March 27, 2018

Question:

Topic: TIMP/DIMP Capital Expenditures and TIMP/DIMP Plant-in-Service Balances
Reference(s): Attachments E, F and G; DOC IR Nos. 14 and 15

A. Response to Part D of DOC IR No. 14 indicates the Attachment E reported capital expenditures exclude both internal labor and removal work in progress (RWIP) costs. Please explain and reconcile the $9.231 million 2018 TIMP Plant-in-Service balance increase (2018 YE $77.453 – 2017 YE $68.222 shown in Attachment F) with the estimated $8.715 million 2018 capital expenditure (Attachment E).

B. Response to Part D of DOC IR No. 15 indicates the Attachment E reported capital expenditures exclude both internal labor and removal work in progress (RWIP) costs.

(1) Please explain and reconcile the $13.483 million 2017 DIMP Plant-in-Service balance increase (2017 YE $38.400 – 2016 YE $24.917 shown in Attachment G) with the estimated $12.969 million 2017 capital expenditure (Attachment E);

(2) Please explain and reconcile the $13.716 million 2016 DIMP Plant-in-Service balance increase (2016 YE $24.917 – 2015 YE $11.201 shown in Attachment G and response to DOC IR No. 15, Part D, Attachment A) with the actual $12.799 million 2016 capital expenditure (Attachment E).

Response:

A. & B. Capital expenditures and plant additions, while linked, are not perfectly correlated, and the amounts usually differ. Most of the capital work in TIMP and DIMP are placed into service on a closing pattern, where a specific percentage of the rolling construction work in progress (CWIP) balance for the project is closed to plant in service each month. In most cases for TIMP and DIMP projects, the specific percentage is less than 100 percent, meaning a residual CWIP balance carries over at the end of each month. Based on the timing of capital expenditures and the closing pattern being used, it is possible to have a greater or lesser increase in plant in service than the capital expenditures in a given year.

In Attachment A to this response (provided in live Excel spreadsheet format), the Company presents a CWIP rollforward for the requested variances with references to Petition Attachment E, F and G provided. The CWIP rollforward displays the CWIP beginning balance, CWIP expenditures, allowance for funds used during construction, closings-book, and CWIP ending balance. Additionally, the CWIP rollforward shows the internal labor amounts which have been excluded from the rate base amounts.

Preparer: James Aurand
Title: Senior Rate Analyst
Department: Revenue Requirements – North
Telephone: 612-337-2076
Date: April 6, 2018

Northern States Power Company

Response to Part A:

TIMP	Jan - 2018	Feb - 2018	Mar - 2018	Apr - 2018	May - 2018	Jun - 2018	Jul - 2018	Aug - 2018	Sep - 2018	Oct - 2018	Nov - 2018	Dec - 2018	Total 2018	
CWIP BEG BAL	1,103,585	695,750	491,560	424,880	754,715	1,060,144	1,532,932	1,956,619	2,596,834	1,031,904	970,356	792,869	1,103,585	
CWIP EXPENDITURES	88,511	88,511	158,998	606,501	606,501	963,678	1,053,791	1,623,965	1,523,178	903,337	610,678	487,632	8,715,280	
AFUDC DEBT	1,644	1,092	863	1,139	1,713	2,496	3,325	4,415	3,728	2,013	1,731	1,407	25,566	
AFUDC EQUITY	2,825	1,876	1,483	1,957	2,942	4,288	5,713	7,585	6,405	3,458	2,974	2,417	43,924	
CLOSINGS-BOOK	(500,816)	(295,668)	(228,025)	(279,762)	(305,727)	(497,675)	(639,142)	(995,749)	(3,098,242)	(970,356)	(792,869)	(642,162)	(9,246,192)	
CWIP END BAL	695,750	491,560	424,880	754,715	1,060,144	1,532,932	1,956,619	2,596,834	1,031,904	970,356	792,869	642,162	642,162	
CWIP BEG BAL INTERNAL LABOR	249,539	249,539	249,539	249,539	249,539	249,539	249,539	249,539	249,539	233,797	233,797	233,797	249,539	
CWIP EXPENDITURES INTERNAL LABOR	-	-	-	-	-	-	-	-	-	-	-	-	-	
CLOSINGS-BOOK INTERNAL LABOR	-	-	-	-	-	-	-	-	(15,742)	-	-	-	(15,742)	
CWIP END BAL INTERNAL LABOR	249,539	249,539	249,539	249,539	249,539	249,539	249,539	249,539	233,797	233,797	233,797	233,797	233,797	
CWIP EXPENDITURES WITHOUT INTERNAL LABOR	88,511	88,511	158,998	606,501	606,501	963,678	1,053,791	1,623,965	1,523,178	903,337	610,678	487,632	8,715,280	*Att. E*
CLOSINGS-BOOK WITHOUT INTERNAL LABOR	(500,816)	(295,668)	(228,025)	(279,762)	(305,727)	(497,675)	(639,142)	(995,749)	(3,082,500)	(970,356)	(792,869)	(642,162)	(9,230,451)	*Att. F change in Plant In-Service*
PLANT ADDITIONS WITHOUT INTERNAL LABOR	500,816	295,668	228,025	279,762	305,727	497,675	639,142	995,749	3,082,500	970,356	792,869	642,162	9,230,451	*Att. F change in Plant In-Service*

Response to Part B (1):

DIMP	Jan - 2017	Feb - 2017	Mar - 2017	Apr - 2017	May - 2017	Jun - 2017	Jul - 2017	Aug - 2017	Sep - 2017	Oct - 2017	Nov - 2017	Dec - 2017	Total 2017	
CWIP BEG BAL	2,036,987	335,220	1,227,513	1,296,161	2,474,258	2,599,043	2,306,627	2,555,801	3,091,169	901,541	678,018	474,206	2,036,987	
CWIP EXPENDITURES	(410,137)	882,949	111,438	1,349,354	1,362,564	961,293	1,301,553	1,973,055	2,033,054	1,875,303	1,405,175	808,060	13,653,661	
AFUDC DEBT	918	1,306	2,132	2,119	2,217	2,206	2,249	2,276	1,335	355	398	382	17,893	
AFUDC EQUITY	1,751	2,539	4,395	4,115	4,383	4,361	4,325	4,437	2,624	698	783	752	35,163	
CLOSINGS-BOOK	(1,294,300)	5,501	(49,317)	(177,491)	(1,244,380)	(1,260,275)	(1,058,954)	(1,444,400)	(4,226,641)	(2,099,879)	(1,610,169)	(971,992)	(15,432,297)	
CWIP END BAL	335,220	1,227,513	1,296,161	2,474,258	2,599,043	2,306,627	2,555,801	3,091,169	901,541	678,018	474,206	311,407	311,407	
CWIP BEG BAL INTERNAL LABOR	1,454,866	1,425,616	1,428,742	1,238,091	1,242,233	1,266,082	1,260,577	1,295,088	1,301,997	241,495	223,573	207,215	1,454,866	
CWIP EXPENDITURES INTERNAL LABOR	2,762	5,609	6,969	4,615	39,173	37,645	57,678	41,398	162,238	149,649	112,133	64,483	684,353	
CLOSINGS-BOOK INTERNAL LABOR	(32,012)	(2,483)	(197,619)	(474)	(15,323)	(43,151)	(23,168)	(34,489)	(1,222,740)	(167,570)	(128,492)	(82,113)	(1,949,634)	
CWIP END BAL INTERNAL LABOR	1,425,616	1,428,742	1,238,091	1,242,233	1,266,082	1,260,577	1,295,088	1,301,997	241,495	223,573	207,215	189,585	189,585	
CWIP EXPENDITURES WITHOUT INTERNAL LABOR	(412,899)	877,339	104,469	1,344,739	1,323,391	923,648	1,243,875	1,931,657	1,870,816	1,725,654	1,293,042	743,577	12,969,308	*Att. E*
CLOSINGS-BOOK WITHOUT INTERNAL LABOR	(1,262,288)	7,984	148,302	(177,017)	(1,229,057)	(1,217,124)	(1,035,786)	(1,409,911)	(3,003,901)	(1,932,309)	(1,481,678)	(889,879)	(13,482,663)	*Att. G change in Plant In-Service*
PLANT ADDITIONS WITHOUT INTERNAL LABOR	1,262,288	(7,984)	(148,302)	177,017	1,229,057	1,217,124	1,035,786	1,409,911	3,003,901	1,932,309	1,481,678	889,879	13,482,663	*Att. G change in Plant In-Service*

Response to Part B (2):

DIMP	Jan - 2016	Feb - 2016	Mar - 2016	Apr - 2016	May - 2016	Jun - 2016	Jul - 2016	Aug - 2016	Sep - 2016	Oct - 2016	Nov - 2016	Dec - 2016	Total 2016	
CWIP BEG BAL	2,404,988	2,627,204	2,661,942	2,815,583	3,317,729	1,498,489	2,101,720	3,530,300	4,507,876	6,127,670	3,736,491	1,675,133	2,404,988	
CWIP EXPENDITURES	601,316	(23,507)	181,885	645,055	747,011	613,228	1,643,453	1,837,524	2,232,503	2,939,927	1,173,837	770,712	13,362,942	
AFUDC DEBT	3,958	3,998	4,528	5,301	4,075	3,108	4,918	7,390	10,546	14,764	17,998	(51,564)	29,020	
AFUDC EQUITY	7,637	8,676	9,999	12,140	9,154	6,975	11,013	16,530	23,599	33,035	40,272	(115,371)	63,659	
CLOSINGS-BOOK	(390,694)	45,571	(42,771)	(160,349)	(2,579,480)	(20,080)	(230,804)	(883,868)	(646,854)	(5,378,905)	(3,293,465)	(241,923)	(13,823,622)	
CWIP END BAL	2,627,204	2,661,942	2,815,583	3,317,729	1,498,489	2,101,720	3,530,300	4,507,876	6,127,670	3,736,491	1,675,133	2,036,987	2,036,987	
CWIP BEG BAL INTERNAL LABOR	998,620	998,801	1,016,813	1,080,599	1,088,817	1,104,676	1,137,771	1,213,942	1,303,772	1,338,137	1,451,948	1,549,627	998,620	
CWIP EXPENDITURES INTERNAL LABOR	181	18,012	63,786	8,218	15,858	33,095	76,172	89,830	34,365	113,811	97,679	12,822	563,828	
CLOSINGS-BOOK INTERNAL LABOR	-	-	-	-	-	-	-	-	-	-	-	(107,583)	(107,583)	
CWIP END BAL INTERNAL LABOR	998,801	1,016,813	1,080,599	1,088,817	1,104,676	1,137,771	1,213,942	1,303,772	1,338,137	1,451,948	1,549,627	1,454,866	1,454,866	
CWIP EXPENDITURES WITHOUT INTERNAL LABOR	601,135	(41,519)	118,098	636,837	731,152	580,133	1,567,281	1,747,694	2,198,138	2,826,116	1,076,158	757,890	12,799,113	*Att. E*
CLOSINGS-BOOK WITHOUT INTERNAL LABOR	(390,694)	45,571	(42,771)	(160,349)	(2,579,480)	(20,080)	(230,804)	(883,868)	(646,854)	(5,378,905)	(3,293,465)	(134,340)	(13,716,039)	*Att. G change in Plant In-Service*
PLANT ADDITIONS WITHOUT INTERNAL LABOR	390,694	(45,571)	42,771	160,349	2,579,480	20,080	230,804	883,868	646,854	5,378,905	3,293,465	134,340	13,716,039	*Att. G change in Plant In-Service*

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Xcel Energy
Docket No.: G002/M-17-787
Response To: MN Department of Commerce Information Request No. 37
Requestors: Dorothy Morrissey, Danielle Winner
Date Received: March 26, 2018

Question:

Topic: Universal Inputs used for revenue requirements
Reference(s): Attachment K

Please file revised schedules and attachments to reflect the following:

(1) new federal tax rates and applying its impact on current/deferred taxes, gross-up for revenue requirement and accumulated deferred income tax;

(2) depreciation method and rates from Docket D-17-581; and

(3) Commission Ordering requirements issued in Docket 16-891.

Response:

(1) Revised schedules reflecting the impact of new federal tax rates are provided in our March 27, 2018 Supplement to the Petition filed in this Docket. The table on page two of the Supplement provides the expected 2018 impact of the 2017 Tax Cut and Jobs Act.

(2) Please see Attachment A to this response for updated revenue requirement calculations reflecting the impact of the depreciation rates proposed in our 2017 Transmission, Distribution, and General Depreciation filing on our proposed 2018 GUIC Rider depreciation. The change in depreciation rates decreases revenue requirements in 2018 by approximately $540,000. Note these new depreciation rates are still being considered by the Commission and have not yet been authorized for depreciation calculations.

(3) The revised Petition attachments provided as Appendix A in our March 27, 2018 Supplement include the updated treatment for DIMP Software Costs

and QA/QC costs resulting from the Commission's February 8, 2018 Order in our 2017 GUIC Rider Filing (Docket 16-891). The table on page two of the Supplement provides the 2018 impact of this updated treatment.

Preparer:	Ryan Cummings
Title:	Senior Financial Analyst
Department:	Revenue Analysis
Telephone:	612-330-1958
Date:	April 5, 2018

MN GUIC Rider - 2018 Annual Tracker Summary

	2018 As Filed Supplement	2018 With Updated Book Depreciation	Difference
Operations & Maintenance Expenses			
TIMP	1,325,877	1,325,877	-
DIMP	3,533,000	3,533,000	-
Total Operations & Maintenance Expenses	4,858,877	4,858,877	-
Capital-Related Revenue Requirements			
TIMP	9,145,450	8,844,383	(301,067)
DIMP	6,254,352	6,018,511	(235,841)
Total Capital-Related Revenue Requirments	15,399,801	14,862,894	(536,908)
Deferred Gas Infrastructure Costs			
TIMP	820,227	820,227	-
DIMP	3,733,856	3,733,856	-
Total Deferred Gas Infrastructure Costs	4,554,083	4,554,083	-
ADIT Prorate	26,416	26,416	-
Revenue Requirement in Base Rates	(480,000)	(480,000)	-
Revenue Requirement Subtotal	**24,359,177**	**23,822,269**	**(536,908)**
Prior Year Carryover	-	-	
Revenue Requirement (RR)	**24,359,177**	**23,822,269**	**(536,908)**
Revenue Collections (RC)	24,359,177	23,822,269	(536,908)
Carryover Balance (RR - RC)	-	-	-

Northern States Power Company

TIMP - Capital Revenue Requirements	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Total
Rate Base													
CWIP	-	-	-	-	-	-	-	-	-	-	-	-	-
Plant In-Service	67,445,701	67,514,771	67,621,242	67,820,416	68,066,117	68,494,499	69,059,708	69,940,020	72,719,853	73,580,769	74,279,573	74,843,215	74,843,215
Less Accumulated Book Depreciation Reserve	(2,225,090)	(3,635,637)	(4,148,758)	(4,214,754)	(4,196,156)	(4,140,537)	(4,069,491)	(3,995,747)	(3,915,753)	(3,828,550)	(3,731,845)	(3,725,785)	(3,725,785)
Less Accumulated Deferred Taxes	7,063,971	7,145,986	7,228,001	7,310,016	7,392,031	7,474,045	7,556,060	7,638,075	7,720,090	7,802,105	7,884,120	7,966,135	7,966,135
End Of Month Rate Base	62,606,821	64,004,422	64,541,999	64,725,154	64,870,243	65,160,990	65,573,139	66,297,692	68,915,516	69,607,215	70,127,298	70,602,865	70,602,865
Average Rate Base (Prior Mo + Cur Month/2)	60,139,181	63,305,621	64,273,211	64,633,577	64,797,699	65,015,617	65,367,065	65,935,415	67,606,604	69,261,365	69,867,256	70,365,082	
Return on Rate Base													
Debt Return (Avg RB * Wtd Cost of Debt)	113,763	119,753	121,583	122,265	122,576	122,988	123,653	124,728	127,889	131,019	132,166	133,107	1,495,491
Equity Return (Avg RB * Wtd Cost of Equity)	263,109	276,962	281,195	282,772	283,490	284,443	285,981	288,467	295,779	303,018	305,669	307,847	3,458,734
Total Return on Rate Base	376,872	396,715	402,779	405,037	406,066	407,431	409,634	413,195	423,668	434,038	437,835	440,955	4,954,224
Income Statement Items													
AFUDC Pre-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-
Property Taxes	94,946	94,946	94,946	94,946	94,946	94,946	94,946	94,946	94,946	94,946	94,946	94,946	1,139,357
Book Depreciation	111,049	111,413	111,508	111,675	111,918	112,286	112,828	113,617	116,147	118,667	119,518	120,207	1,370,834
Deferred Taxes	82,015	82,015	82,015	82,015	82,015	82,015	82,015	82,015	82,015	82,015	82,015	82,015	984,179
Gross Up for Income Tax (see below)	29,261	35,025	35,954	29,436	30,140	26,638	25,373	22,529	24,954	40,268	46,878	49,333	395,789
Total Income Statement Expense	317,271	323,399	324,424	318,072	319,019	315,885	315,163	313,107	318,063	335,896	343,358	346,502	3,890,159
Total Revenue Requirement	**694,143**	**720,115**	**727,202**	**723,110**	**725,085**	**723,316**	**724,796**	**726,303**	**741,731**	**769,934**	**781,192**	**787,456**	**8,844,383**
Capital Structure													
Weighted Cost of Debt	2.27%												
Weighted Cost of Equity	5.25%												
Required Rate of Return	7.52%												
Current Income Tax Calculation													
Equity Return	263,109	276,962	281,195	282,772	283,490	284,443	285,981	288,467	295,779	303,018	305,669	307,847	3,458,734
Book Depreciation	111,049	111,413	111,508	111,675	111,918	112,286	112,828	113,617	116,147	118,667	119,518	120,207	1,370,834
Deferred Taxes	82,015	82,015	82,015	82,015	82,015	82,015	82,015	82,015	82,015	82,015	82,015	82,015	984,179
Less Tax Depreciation	383,763	383,763	385,899	404,531	404,936	416,440	423,246	435,584	438,965	408,620	395,521	391,971	4,873,238
Plus CPI-Tax Interest (If Applicable)	134	209	318	1,047	2,236	3,737	5,327	7,338	6,892	4,755	4,540	4,210	40,742
Total	72,544	86,836	89,138	72,978	74,723	66,041	62,905	55,853	61,868	99,834	116,222	122,308	981,251
Tax Rate (T/(1-T)	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351
Gross Up for Income Tax	29,261	35,025	35,954	29,436	30,140	26,638	25,373	22,529	24,954	40,268	46,878	49,333	395,789

Northern States Power Company

DIMP - Capital Revenue Requirements	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Total
Rate Base													
CWIP	-	-	-	-	-	-	-	-	-	-	-	-	-
Plant In-Service	37,253,149	37,917,701	38,406,452	39,164,233	40,874,026	43,217,516	45,620,116	49,255,621	52,710,885	56,362,264	59,507,734	61,121,272	61,121,272
Less Accumulated Book Depreciation Reserve	(5,909,857)	(5,907,980)	(5,928,762)	(5,905,682)	(5,930,433)	(5,981,675)	(6,025,210)	(6,098,015)	(6,150,872)	(6,202,893)	(6,234,909)	(6,184,776)	(6,184,776)
Less Accumulated Deferred Taxes	5,530,086	5,617,495	5,704,904	5,792,313	5,879,722	5,967,131	6,054,540	6,141,949	6,229,358	6,316,767	6,404,176	6,491,585	6,491,585
End Of Month Rate Base	37,632,920	38,208,186	38,630,310	39,277,602	40,924,737	43,232,060	45,590,785	49,211,687	52,632,399	56,248,390	59,338,468	60,814,463	60,814,463
Average Rate Base (Prior Mo + Cur Month/2)	36,752,869	37,920,553	38,419,248	38,953,956	40,101,170	42,078,399	44,411,423	47,401,236	50,922,043	54,440,394	57,793,429	60,076,465	
Return on Rate Base													
Debt Return (Avg RB * Wtd Cost of Debt)	69,524	71,733	72,676	73,688	75,858	79,598	84,012	89,667	96,328	102,983	109,326	113,645	1,039,038
Equity Return (Avg RB * Wtd Cost of Equity)	160,794	165,902	168,084	170,424	175,443	184,093	194,300	207,380	222,784	238,177	252,846	262,835	2,403,061
Total Return on Rate Base	230,318	237,635	240,761	244,111	251,301	263,691	278,312	297,048	319,111	341,160	362,172	376,479	3,442,099
Income Statement Items													
AFUDC Pre-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-
Property Taxes	50,433	50,433	50,433	50,433	50,433	50,433	50,433	50,433	50,433	50,433	50,433	50,433	605,194
Book Depreciation	66,990	68,911	69,870	70,906	72,957	76,326	80,271	85,290	91,184	97,091	102,740	106,696	989,230
Deferred Taxes	87,409	87,409	87,409	87,409	87,409	87,409	87,409	87,409	87,409	87,409	87,409	87,409	1,048,908
Gross Up for Income Tax (see below)	7,275	7,474	8,923	(1,127)	(29,054)	(36,830)	(23,926)	(54,304)	(17,825)	(13,676)	16,538	69,611	(66,920)
Total Income Statement Expense	212,106	214,227	216,635	207,621	181,745	177,337	194,187	168,828	211,200	221,257	257,120	314,149	2,576,411
Total Revenue Requirement	**442,424**	**451,862**	**457,395**	**451,732**	**433,045**	**441,029**	**472,499**	**465,875**	**530,312**	**562,416**	**619,293**	**690,628**	**6,018,511**
Capital Structure													
Weighted Cost of Debt	2.27%												
Weighted Cost of Equity	5.25%												
Required Rate of Return	7.52%												
Current Income Tax Calculation													
Equity Return	160,794	165,902	168,084	170,424	175,443	184,093	194,300	207,380	222,784	238,177	252,846	262,835	2,403,061
Book Depreciation	66,990	68,911	69,870	70,906	72,957	76,326	80,271	85,290	91,184	97,091	102,740	106,696	989,230
Deferred Taxes	87,409	87,409	87,409	87,409	87,409	87,409	87,409	87,409	87,409	87,409	87,409	87,409	1,048,908
Less Tax Depreciation	298,255	304,545	304,465	333,716	412,773	447,994	433,769	533,514	471,161	488,032	438,140	321,696	4,788,061
Plus CPI-Tax Interest (If Applicable)	1,098	853	1,226	2,184	4,934	8,856	12,472	18,803	25,591	31,450	36,146	37,339	180,953
Total	18,036	18,530	22,123	(2,794)	(72,031)	(91,311)	(59,317)	(134,632)	(44,193)	(33,906)	41,002	172,582	(165,910)
Tax Rate (T/(1-T)	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351
Gross Up for Income Tax	7,275	7,474	8,923	(1,127)	(29,054)	(36,830)	(23,926)	(54,304)	(17,825)	(13,676)	16,538	69,611	(66,920)

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Xcel Energy
Docket No.: G002/M-17-787
Response To: MN Department of Commerce Information Request No. 43
Requestor: Dorothy Morrissey, Danielle Winner
Date Received: March 29, 2018

Question:

Topic: Revenue Requirement Category Descriptions – Property Taxes
Reference(s): Attachment P, p. 2 and Attachment K

In Attachment P, the petition states "the estimated annual 2018 property tax amount for GUIC projects, the $1,159,565 for TIMP (Attachment F) and $652,677 for DIMP (Attachment G) reflect property tax rates from the pay-2017 tax year using plan in service as of December 31,2015 for property taxation." In Attachment K, the universal input for property taxes is 1.7 percent.

A. Please provide the calculation for the 2018 TIMP and DIMP property tax amounts.

B. Please provide support for the property tax rate of 1.7 percent.

C. Please provide the calculation for the 2016 TIMP property taxes (Attachment F, page 1).

D. Please provide the calculation for the 2016 DIMP property taxes (Attachment G, p. 1).

E. Please provide support that depreciation on the plant-in-service is not considered by the Minnesota Department of Revenue when determining Minnesota utility property tax assessment.

Response:

A. Please see Attachment A to this response for the calculation. The property tax amount is calculated as the Plant Balance multiplied by the Property Tax Rate.

B. Total tax paid for gas personal property was $17,153,282, and when divided by total original cost of personal property of $1,009,203,759, a 1.7percent tax rate is derived.

C. See Attachment A to this response for the calculation. The property tax amount is calculated as the Plant Balance multiplied by the Property Tax Rate.

D. See Attachment A to this response for the calculation. The property tax amount is calculated as the Plant Balance multiplied by the Property Tax Rate.

E. Depreciation is used by the MNDOR in calculating our assessed value, but it is not considered when apportioning that value to the local taxing jurisdictions. In Minnesota administrative rule 8100.0600 Apportionment, Subpart 4 Market value of the operating utility property states:

"The total market value of each company's operating utility property in Minnesota shall be:

The current original cost in each taxing district as of the last assessment date plus original cost of new construction reduced by the original cost of property retired since the last assessment date. The Minnesota portion of the unit value as adjusted under this rule shall be divided by the total current original cost to determine a percentage. The resulting percentage shall be multiplied by the current original cost in each taxing district to determine the market value in each district."

Preparers:	Ryan Cummings / Paul Koepke
Title:	Senior Financial Analyst / Consultant, Tax Reporting
Department:	Revenue Analysis / Tax Services
Telephone:	612-330-1958 / 612-330-6835
Date:	April 9, 2018

	Jan - 2016	Feb - 2016	Mar - 2016	Apr - 2016	May - 2016	Jun - 2016	Jul - 2016	Aug - 2016	Sep - 2016	Oct - 2016	Nov - 2016	Dec - 2016	Total
DIMP													
Plant Balance	11,201,196	11,201,196	11,201,196	11,201,196	11,201,196	11,201,196	11,201,196	11,201,196	11,201,196	11,201,196	11,201,196	11,201,196	11,201,196
Property Tax Calculated	15,865	15,865	15,865	15,865	15,865	15,865	15,865	15,865	15,865	15,865	15,865	15,865	190,385
Property Tax Rate	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	1.70%
TIMP													
Plant Balance	41,156,947	41,156,947	41,156,947	41,156,947	41,156,947	41,156,947	41,156,947	41,156,947	41,156,947	41,156,947	41,156,947	41,156,947	41,156,947
Property Tax Calculated	58,295	58,295	58,295	58,295	58,295	58,295	58,295	58,295	58,295	58,295	58,295	58,295	699,538
Property Tax Rate	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	1.70%

	Jan - 2017	Feb - 2017	Mar - 2017	Apr - 2017	May - 2017	Jun - 2017	Jul - 2017	Aug - 2017	Sep - 2017	Oct - 2017	Nov - 2017	Dec - 2017	Total
DIMP													
Plant Balance	24,917,235	24,917,235	24,917,235	24,917,235	24,917,235	24,917,235	24,917,235	24,917,235	24,917,235	24,917,235	24,917,235	24,917,235	24,917,235
Property Tax Calculated	35,293	35,293	35,293	35,293	35,293	35,293	35,293	35,293	35,293	35,293	35,293	35,293	423,514
Property Tax Rate	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	1.70%
TIMP													
Plant Balance	59,397,911	59,397,911	59,397,911	59,397,911	59,397,911	59,397,911	59,397,911	59,397,911	59,397,911	59,397,911	59,397,911	59,397,911	59,397,911
Property Tax Calculated	84,131	84,131	84,131	84,131	84,131	84,131	84,131	84,131	84,131	84,131	84,131	84,131	1,009,577
Property Tax Rate	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	1.70%

	Jan - 2018	Feb - 2018	Mar - 2018	Apr - 2018	May - 2018	Jun - 2018	Jul - 2018	Aug - 2018	Sep - 2018	Oct - 2018	Nov - 2018	Dec - 2018	Total
DIMP													
Plant Balance	38,399,899	38,399,899	38,399,899	38,399,899	38,399,899	38,399,899	38,399,899	38,399,899	38,399,899	38,399,899	38,399,899	38,399,899	38,399,899
Property Tax Calculated	54,390	54,390	54,390	54,390	54,390	54,390	54,390	54,390	54,390	54,390	54,390	54,390	652,677
Property Tax Rate	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	1.70%
TIMP													
Plant Balance	68,222,346	68,222,346	68,222,346	68,222,346	68,222,346	68,222,346	68,222,346	68,222,346	68,222,346	68,222,346	68,222,346	68,222,346	68,222,346
Property Tax Calculated	96,630	96,630	96,630	96,630	96,630	96,630	96,630	96,630	96,630	96,630	96,630	96,630	1,159,565
Property Tax Rate	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	1.70%

From: Peterson, Lisa R
To: Morrissey, Dorothy (COMM)
Subject: RE: Clarification of response to DOC IR 43 in Dkt 17-787
Date: Wednesday, April 11, 2018 3:45:54 PM
Attachments: image001.png

Hi Dorothy,

The $17,153,282 amount represents the actual property taxes paid in 2017. The $1,009,203,709 amount represents the original cost of gas utility property as of 12/31/15. The 1.7% property tax rate is the property taxes paid of $17.2 million divided by the $1.0 billion in property costs.

Please let me know if you have any questions.
Thanks,
Lisa

From: Morrissey, Dorothy (COMM) [mailto:dorothy.morrissey@state.mn.us]
Sent: Tuesday, April 10, 2018 2:51 PM
To: Peterson, Lisa R
Subject: Clarification of response to DOC IR 43 in Dkt 17-787

Hi Lisa,

Welcome back. I have a question on the response to DOC IR #43 in Dkt 17-787. I'd like the values $17,153,282 and $1,009,203,709 within the response clarified. It is not clear to me what year the tax paid amount of $17,153,282 is related to and what was measurement date for the $1,009,203,709 personal property amount.

Thank you for your assistance,

Dorothy Morrissey
Public Utilities Financial Analyst
651-539-1797
mn.gov/commerce
Minnesota Department of Commerce
85 7th Place East, Suite 280 | Saint Paul, MN 55101

COMMERCE DEPARTMENT

BEFORE THE MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS
600 North Robert Street
St. Paul, MN 55101

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION
121 7th Place East, Suite 350
St Paul MN 55101-2147

IN THE MATTER OF THE APPLICATION OF CENTERPOINT ENERGY RESOURCES CORP., D/B/A CENTERPOINT ENERGY MINNESOTA GAS FOR AUTHORITY TO INCREASE RATES FOR NATURAL GAS SERVICE IN MINNESOTA	MPUC Docket No. G008/GR-17-285 OAH Docket No. 19-2500-34684

DIRECT TESTIMONY AND ATTACHMENTS OF MARK A. JOHNSON

ON BEHALF OF

THE MINNESOTA DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

FINANCIAL ISSUES

JANUARY 8, 2018

Q. What is the effect of your recommendation on the test year?

A. My recommendation reduces CPE's test-year workers compensation expense by $700,466 on a total Company basis or $393,314 on a regulated Company basis. DOC Ex.___at MAJ-19 (Johnson Direct).

XIII. NORMALIZATION AND PRORATED ACCUMULATED DEFERRED INCOME TAXES

Q. What is normalization?

A. CPE Witness, Mr. Charles W. Pringle, provided the following definition of normalization in his testimony:

> Normalized accounting is based on requirements set forth in Generally Accepted Accounting Principles ("GAAP"), to recognize the amount of taxes payable or refundable in the current year and to recognize deferred tax liabilities and assets for the future tax consequences of events that have been recognized in an entity's financial statements or tax returns. For regulatory purposes those deferred tax liabilities and/or assets impact the rate base upon which the utility is allowed to earn a return. FERC Order No. 144, issued in 1981, requires companies under FERC regulatory jurisdiction to determine their income tax allowance on a fully normalized basis. Normalization matches the income tax expense or benefit with items as they are recorded on the books. As a result, the customers paying for an expense item also receive the related income tax benefit – the most equitable result.
>
> Furthermore, the Internal Revenue Code ("IRC") requires the use of normalization as a prerequisite to claiming accelerated depreciation and certain tax credits. The IRC normalization rules basically require inclusion of deferred income tax expense in cost of service with the resulting ADIT [Accumulated Deferred Income Taxes] reducing rate base. If the tax benefits are not normalized in the ratemaking process, CNP loses the right to claim these benefits in its income tax filings. The loss of accelerated

> depreciation would significantly increase rate base to the detriment of our ratepayers, due to the elimination of the ADIT offset to rate base.

CPE Ex.___ at 6-7 (Pringle Direct).

Q. What are Accumulated Deferred Income Taxes (ADIT)?

A. Mr. Pringle stated that:

> ADIT represents a net deferred tax liability for the estimated future tax effects attributable to temporary differences based on the provisions of the enacted tax law. The effects of future changes in tax laws or rates are not contemplated as part of the calculation of ADIT.
>
> ….
>
> ADIT arises from the interaction of the IRC [Internal Revenue Code], the Company's accounting practices under GAAP, and the Company's operations. To be specific, ADIT assets and liabilities are created because of differences in the treatment of certain items between the IRC and the Company's accounting under GAAP. The Company's accounting books and records are kept under GAAP, which provides guiding principles and requirements as to when and how CenterPoint Energy Minnesota Gas records its financial results. By contrast, the IRC and the related regulations provide the rules and requirements CNP follows when completing its tax filings. These differences in methodology create temporary differences that result in recognition of deferred income taxes.

CPE Ex.___ at 7 (Pringle Direct).

In other words, normalization accounts for tax timing differences between GAAP accounting/ratemaking and tax accounting/income tax filings. Specifically, the Internal Revenue Code allows utilities to depreciate assets quickly (accelerated depreciation) while ratemaking requires an equal amount of the asset to be depreciated each year (uniform depreciation). As a result, for tax purposes CPE pays a lower level of income tax expense due to higher depreciation at the beginning of an asset's life. For ratemaking, income tax expense is more levelized due to straight-line or uniform depreciation. This difference between income tax expense for tax purposes and income tax expense for book/ ratemaking purposes results in the recording of deferred income taxes on the income statement (deferred income tax expense) and balance sheet (accumulated deferred income taxes).

Q. How have ADIT balances generally been treated for ratemaking purposes in Minnesota?

A. Similar to other rate base items, utilities have used a simple average of their beginning and ending test-year ADIT balances (or a 13 month average) to determine the amount to include in test-year rate base.

Q. Did CPE use a simple average of its beginning and ending test-year ADIT balances or a 13-month average to determine the amount to include in test-year rate base in this proceeding?

A. No. As explained in the Direct Testimony of Company Witness, Mr. Charles W. Pringle, there are specific normalization requirements for periods that employ a future test year. Internal Revenue Service Regulation Section 1.167(l)-1(h)(6) provides that ratemaking procedures and adjustments must be consistent with normalization accounting. When a utility chooses to use a forecast test year to determine depreciation, the IRS requires that "the amount of the reserve account for the period is the amount of the reserve at the beginning of the period and a pro rata portion of the amount of any projected increase to be credited or decrease to be charged to the account during such period." This is generally referred to as the "Proration Rule."

The pro rata amount of any increase or decrease during the future portion of the period is determined by multiplying the increase or decrease by a fraction, the numerator of which is the number of days remaining in the period at the time the increase is to accrue, and the denominator of which is the total number of days in the future portion of the period. This is generally referred to as the "Proration Methodology." CPE Ex.___ at 11-13 (Pringle Direct).

Q. Does the Proration Methodology apply to all ADIT balances included in rate base?

A. No. The Proration Methodology only applies to federal income tax ADIT balances that are related to depreciation expense. CPE Ex.___ at 12 (Pringle Direct).

Q. What effect does the Proration Methodology have on CPE's proposed test-year federal ADIT balances in this proceeding?

A. The Proration Methodology reduces CPE's proposed test-year federal ADIT credit balance, which increases rate base by $2,870,801. CPE Ex.___ (DAP-WP), Sch. 7, Workpaper 2, p. 2 of 5 (Poppie Direct Workpapers). This reduction in ADIT results in a test-year revenue requirement increase of $322,678. CPE Ex.___ at 13 (Pringle Direct).

Q. Is this the first time CPE has applied the Proration Rule in a Minnesota rate case proceeding?

A. Yes. CPE stated that since the preparation and filing of its 2015 Rate Case it became aware of several IRS private letter rulings (PLRs) that required utilities to use the Proration Methodology for future test years. Based on these PLRs, CPE stated that it was concerned that it too must apply the Proration Methodology to in order to ensure compliance with normalization rules. In order to gain clarity on this issue and ensure compliance with normalization rules, CPE stated that it filed its own PLR request with the IRS. Although at the time of filing its rate case CPE had yet to receive the IRS's response, the Company requested that the Commission approve the use of the Proration Methodology in this proceeding in order to avoid the risk of violating normalization rules. CPE Ex.___ at 13 (Pringle Direct).

Q. When did CPE file its PLR request with IRS and when will it receive its formal response?

A. CPE filed its PLR request with the IRS on July 28, 2017. Since the IRS normally takes about six months to issue its formal response, I expect the formal response in approximately late January, 2018.

Q. Has the Commission addressed the prorated ADIT issue before in a Minnesota rate case proceeding?

A. Yes. The Commission recently addressed this issue in Otter Tail Power Company's 2015 Rate Case (Docket No. E017/GR-15-1033). Similar to CPE, Otter Tail Power Company (OTP) filed its own PLR request with the IRS. In its PLR response, the IRS ruled that prorated ADIT did not need to be reflected in OTP's final rates because final rates were implemented after the future test-year period had ended. However, the IRS ruled that prorated ADIT applied to interim rates because they were implemented before the end of the future test-year period. Moreover, the IRS ruled that the effects of proration included in interim rates could not be undone or returned to ratepayers in the interim rate refund process.[31]

Q. What do conclude?

A. While I expect that the IRS will rule the same in CPE's PLR and determine that prorated ADIT does not need to be included in final rates, I recommend that the Commission accept CPE's test-year proration of ADIT until the IRS issues its formal response to CPE's PLR request. I will make my final recommendations later in this proceeding after I have reviewed the IRS's formal response.

[31] See Docket No. E017/GR-15-1033, OTP Supplemental Reply Comments at 2 (October 4, 2017).

Surrebuttal Testimony
Mr. Charles Pringle

Before the Public Utilities Commission of
The State of Minnesota

In the Matter of the Application of
CenterPoint Energy Resources Corp., d/b/a
CenterPoint Energy Minnesota Gas
For Authority to Increase Rates for Natural Gas Utility
Service in Minnesota

Docket No. G-008/GR-17-285
Exhibit______(CWP-S)

Income Taxes/ADIT Proration

February 27, 2018

reported on Table 4 and Table 5 of my Rebuttal Testimony. Between the date of filing the Rebuttal Testimony and the filing of our annual financial statements (Form 10-K), these amounts were remeasured. Please see the updates to Tables 4 and 5 in section III of my Surrebuttal Testimony.

II. ADIT Proration

Q. Mr. Johnson, in his Direct Testimony, recommended that the Commission accept the proration of ADIT until the IRS issues its response to the Company's request for a PLR. Has the IRS issued its response?

A. Yes. As I stated in my Rebuttal Testimony, the Company received the IRS PLR on January 29, 2018. [1]

Q. Why did the Company request a PLR?

A. The Company requested several specific rulings to interpret and apply the IRS regulations. Primarily, the requested rulings applied to the proper proration of ADIT to avoid a violation of IRS normalization requirements. It is important to avoid a violation of normalization requirements so the Company can continue to make use of accelerated depreciation which provides significant benefits to ratepayers.

Q. Please explain proration of ADIT.

[1] Exhibit___(CWP-S) Schedule 1- IRS PLR-12344-17, dated January 25, 2018.

A. The Treasury regulations provide a specific formula to prorate the additions or reductions to ADIT reserve over a future test period for purposes of setting utility rates.[2] The formula requires that a pro rata portion of any increase or decrease to the reserve be adjusted by a fraction. The numerator in the fraction is the number of days remaining in the period from when the adjustment to the reserve is accrued. The denominator is the total number of days in the future period. If balances to the ADIT depreciation reserve account are increasing, the proration formula has the effect of reducing ADIT and increasing rate base. If the ADIT deprecation reserve balances are decreasing the formula will have the opposite effect and will increase ADIT and decrease rate base.

Q. What determinations were made by the IRS in the PLR?

A. The PLR determined, subject to the specific facts and circumstances presented in the Company's request, that:

- The test period for interim rates is a future test period and *is* subject to the ADIT proration rules,
- Because the interim rate refund process is implemented after the end of the test period, it uses a historical test period and is *not* required to employ the proration methodology, and

[2] *See* Treas. Reg. § 1.167(l)-1(h)(6).

- Because final rates are implemented after the end of the test year, the computation uses an historical period and is therefore *not* required to employ the proration methodology.

Q. Did the PLR make other determinations?

A. Yes. The PLR further found:

- That the Consistency Rule[3] does not require the use of the same averaging procedure used for other components of rate base to be applied to prorated ADIT,
- That use of a simple average for certain components of rate base and a 13-month average for ADIT is not a violation of the Consistency Rule,
- That the proration requirement does not apply only to the difference between the ADIT balance used to set interim rates and the balance used to compute final rates, and
- The Company's failure to comply with the Normalization Rules in its prior general rate case was inadvertent and because the Company took corrective action in this rate filing, which was its earliest available opportunity, that it was not appropriate to apply the sanction of denial of accelerated depreciation.

Q. Did the Company prorate ADIT in its original filing?

[3] As described in the PLR, the "Consistency Rule" means "In order to satisfy the requirements of 168(i)(9)(B), there must be consistency in the treatment of costs for rate base, regulated depreciation expense, tax expense, and deferred tax revenue purposes."

A. Yes. This information was used as the basis for interim rates and was therefore consistent with the PLR. In addition, the Company used this information as the basis for its proposed final rates.

Q. Should the calculation of ADIT for purposes of setting final rates use proration?

A. No. To be consistent with the PLR, ADIT for final rates should not be prorated.

Q. How does the PLR apply to the calculation of the interim rate refund?

A. As noted above, the PLR stated that the interim rate refund process uses a historical test period and therefore does not employ the proration methodology. The Company intends to discuss with parties how this can be accomplished and will further address this issue in its compliance filing and interim rate refund plan.

Q. You stated that ADIT for final rates should not be prorated, but the original filing includes ADIT proration. Have you calculated the difference between prorating and not prorating ADIT?

A. Yes. Using the information in our original filing, proration of ADIT results in a 13-month average ADIT of $319.3 million. If ADIT is not prorated, the 13-month average ADIT is $322.2 million. The difference of $2.9 million is an increase in ADIT and therefore a corresponding decrease in rate base if proration is not utilized. I have attached these calculations as Exhibit___(CWP-S) Schedule 2. Mr. Poppie discussed the relationship between ADIT and rate base in his Rebuttal Testimony.

Q. Is the difference of $2.9 million the adjustment you recommend?

A. No. This amount reflects the original filed information and does not reflect adjustments recommended by the Company or any other party. The final ADIT amount should be determined after all other adjustments have been calculated and the additions to ADIT in the test year should not be prorated for purposes of determining final rates.

III. REVISED UNPROTECTED OTHER EDIT

Q. What updates or corrections do you have from your Rebuttal Testimony?

A. As I noted in my rebuttal testimony, the information related to the impact of the TCJA to the Company was preliminary and subject to change. Since filing my rebuttal testimony, the December 31, 2017 balance of unprotected other EDIT and subsequent 2018 amortization were revised slightly, resulting in a small increase in the amount of funds that will be returned to ratepayers.

Q. What is the total amount of EDIT and associated regulatory liability due to the TCJA?

A. The EDIT and associated regulatory liabilities recorded per book as of December 31, 2017 are shown in Table 4 below. Note that the balance of Unprotected (Other using 2-year) is updated. Other amounts on the table are unchanged.

criteria given in § 388.4 of MARAD's regulations at 46 CFR part 388.

Privacy Act

Anyone is able to search the electronic form of all comments received into any of our dockets by the name of the individual submitting the comment (or signing the comment, if submitted on behalf of an association, business, labor union, etc.). You may review DOT's complete Privacy Act Statement in the **Federal Register** published on April 11, 2000 (Volume 65, Number 70; Pages 19477–78).

By Order of the Maritime Administrator.

Dated: April 26, 2012.

Julie P. Agarwal,

Secretary, Maritime Administration.

[FR Doc. 2012–10864 Filed 5–4–12; 8:45 am]

BILLING CODE 4910–81–P

DEPARTMENT OF TRANSPORTATION

Maritime Administration

[Docket No. MARAD–2012–0056]

Requested Administrative Waiver of the Coastwise Trade Laws: Vessel LONGWOOD BATEAU; Invitation for Public Comments

AGENCY: Maritime Administration, Department of Transportation.

ACTION: Notice.

SUMMARY: As authorized by 46 U.S.C. 12121, the Secretary of Transportation, as represented by the Maritime Administration (MARAD), is authorized to grant waivers of the U.S.-build requirement of the coastwise laws under certain circumstances. A request for such a waiver has been received by MARAD. The vessel, and a brief description of the proposed service, is listed below.

DATES: Submit comments on or before June 6, 2012.

ADDRESSES: Comments should refer to docket number MARAD–2012–0056. Written comments may be submitted by hand or by mail to the Docket Clerk, U.S. Department of Transportation, Docket Operations, M–30, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE., Washington, DC 20590. You may also send comments electronically via the Internet at *http://www.regulations.gov.* All comments will become part of this docket and will be available for inspection and copying at the above address between 10 a.m. and 5 p.m., E.T., Monday through Friday, except federal holidays. An electronic version of this document and all documents entered into this docket is available on the World Wide Web at *http://www.regulations.gov.*

FOR FURTHER INFORMATION CONTACT: Joann Spittle, U.S. Department of Transportation, Maritime Administration, 1200 New Jersey Avenue SE., Room W21–203, Washington, DC 20590. Telephone 202–366–5979, Email *Joann.Spittle@dot.gov.*

SUPPLEMENTARY INFORMATION: As described by the applicant the intended service of the vessel LONGWOOD BATEAU is: INTENDED COMMERCIAL USE OF VESSEL: ''Day outings, harbor cruises and sightseeing cruises for no more than six passengers with one licensed captain on a seasonal basis.'' GEOGRAPHIC REGION: ''Massachusetts, Rhode Island, Connecticut and New York.''

The complete application is given in DOT docket MARAD–2012–0056 at *http://www.regulations.gov.* Interested parties may comment on the effect this action may have on U.S. vessel builders or businesses in the U.S. that use U.S.-flag vessels. If MARAD determines, in accordance with 46 U.S.C. 12121 and MARAD's regulations at 46 CFR Part 388, that the issuance of the waiver will have an unduly adverse effect on a U.S.-vessel builder or a business that uses U.S.-flag vessels in that business, a waiver will not be granted. Comments should refer to the docket number of this notice and the vessel name in order for MARAD to properly consider the comments. Comments should also state the commenter's interest in the waiver application, and address the waiver criteria given in § 388.4 of MARAD's regulations at 46 CFR Part 388.

Privacy Act

Anyone is able to search the electronic form of all comments received into any of our dockets by the name of the individual submitting the comment (or signing the comment, if submitted on behalf of an association, business, labor union, etc.). You may review DOT's complete Privacy Act Statement in the **Federal Register** published on April 11, 2000 (Volume 65, Number 70; Pages 19477–78).

By Order of the Maritime Administrator.

Dated: April 26, 2012.

Julie P. Agarwal,

Secretary, Maritime Administration.

[FR Doc. 2012–10867 Filed 5–4–12; 8:45 am]

BILLING CODE 4910–81–P

DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

[Docket No. PHMSA–2012–0068]

Pipeline Safety: Verification of Records

AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA), DOT.

ACTION: Notice; Issuance of Advisory Bulletin.

SUMMARY: PHMSA is issuing an Advisory Bulletin to remind operators of gas and hazardous liquid pipeline facilities to verify their records relating to operating specifications for maximum allowable operating pressure (MAOP) required by 49 CFR 192.517 and maximum operating pressure (MOP) required by 49 CFR 195.310. This Advisory Bulletin informs gas operators of anticipated changes in annual reporting requirements to document the confirmation of MAOP, how they will be required to report total mileage and mileage with adequate records, when they must report, and what PHMSA considers an adequate record. In addition, this Advisory Bulletin informs hazardous liquid operators of adequate records for the confirmation of MOP.

FOR FURTHER INFORMATION CONTACT: John Gale by phone at 202–366–0434 or by email at *john.gale@dot.gov.* Information about PHMSA may be found at *http://phmsa.dot.gov.*

SUPPLEMENTARY INFORMATION:

Background

On January 10, 2011, PHMSA issued Advisory Bulletin 11–01. This Advisory Bulletin reminded operators that if they are relying on the review of design, construction, inspection, testing and other related data to establish MAOP and MOP, they must ensure that the records used are reliable, traceable, verifiable, and complete. If such a document and records search, review, and verification cannot be satisfactorily completed, the operator cannot rely on this method for calculating MAOP or MOP and must instead rely on another method as allowed in 49 CFR 192.619 or 49 CFR 195.406.

Section 192.619 currently contains four methods for establishing MAOP: (1) The design pressure of the weakest element in the segment; (2) pressure testing; (3) the highest actual operating pressure in the five years prior to the segment becoming subject to regulation under Part 192; and (4) the maximum safe pressure considering the history of the segment, particularly known corrosion and the actual operating pressure. The third method, often referred to as the ''grandfather clause,'' allows pipelines that had safely operated prior to the pipeline safety MAOP regulations to continue to operate under similar conditions without retroactively applying recordkeeping requirements or requiring pressure tests.

Many of the pipelines being newly subjected to safety regulation in the 1970's were relatively new and had demonstrated a safe operating history. PHMSA is now considering whether these pipelines should be pressure tested to verify continued safe MAOP. In its August 20, 2011, accident investigation report on the September 9, 2010, Pacific Gas and Electric Company natural gas transmission pipeline rupture and fire, the National Transportation Safety Board (NTSB) recommended that PHMSA should:

> Amend Title 49 CFR 192.619 to delete the grandfather clause and require that all gas transmission pipelines constructed before 1970 be subjected to a hydrostatic pressure test that incorporates a spike test. (P–11–14)

PHMSA will be addressing this recommendation in a future rulemaking.

On January 3, 2012, President Obama signed the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (Act), which requires PHMSA to direct each owner or operator of a gas transmission pipeline and associated facilities to provide verification that their records accurately reflect MAOP of their pipelines within Class 3 and Class 4 locations and in Class 1 and Class 2 locations in High Consequence Areas (HCAs). Beginning in 2013, PHMSA intends to require operators to submit data regarding verification of records in these class locations via the Gas Transmission and Gathering Systems Annual Report.

Operators of both gas and hazardous liquid pipelines should review their records to determine whether they are adequate to support operating parameters and conditions on their pipeline systems or if additional action is needed to confirm those parameters and assure safety. The Research and Special Programs Administration and the Materials Transportation Bureau, PHMSA's predecessor agencies, recognized the importance of verifying MAOP. Prior to 1996, there was a regulatory requirement titled: ''Initial Determination of Class Location and Confirmation or Establishment of Maximum Allowable Operating Pressure'' at 49 CFR 192.607. This regulation required operators to confirm the MAOP on their systems relative to class locations no later than January 1, 1973. The regulatory requirement was removed in 1996 because the compliance dates had long since passed. PHMSA believes documentation that was used to confirm MAOP in compliance with this requirement may be useful in the current verification effort.

Advisory Bulletin (ADB–2012–06)

To: Owners and Operators of Gas and Hazardous Liquid Pipeline Systems.

Subject: Verification of Records Establishing MAOP and MOP.

Advisory: As directed in the Act, PHMSA will require each owner or operator of a gas transmission pipeline and associated facilities to verify that their records confirm MAOP of their pipelines within Class 3 and Class 4 locations and in Class 1 and Class 2 locations in HCAs.

PHMSA intends to require gas pipeline operators to submit data regarding mileage of pipelines with verifiable records and mileage of pipelines without records in the annual reporting cycle for 2013. On April 13, 2012, (77 FR 22387) PHMSA published a **Federal Register** Notice titled: ''Information Collection Activities, Revision to Gas Transmission and Gathering Pipeline Systems Annual Report, Gas Transmission and Gathering Pipeline Systems Incident Report, and Hazardous Liquid Pipelines Systems Accident Report.'' PHMSA plans to use information from the 2013 Gas Transmission and Gathering Pipeline Systems Annual Report to develop potential rulemaking for cases in which the records of the owner or operator are insufficient to confirm the established MAOP of a pipeline segment within Class 3 and Class 4 locations and in Class 1 and Class 2 locations in HCAs. Owners and operators should consider the guidance in this advisory for all pipeline segments and take action as appropriate to assure that all MAOP and MOP are supported by records that are traceable, verifiable and complete.

Information needed to support establishment of MAOP and MOP is identified in § 192.619, § 192.620 and § 195.406. An owner or operator of a pipeline must meet the recordkeeping requirements of Part 192 and Part 195 in support of MAOP and MOP determination.

Traceable records are those which can be clearly linked to original information about a pipeline segment or facility. Traceable records might include pipe mill records, purchase requisition, or as-built documentation indicating minimum pipe yield strength, seam type, wall thickness and diameter. Careful attention should be given to records transcribed from original documents as they may contain errors. Information from a transcribed document, in many cases, should be verified with complementary or supporting documents.

Verifiable records are those in which information is confirmed by other complementary, but separate, documentation. Verifiable records might include contract specifications for a pressure test of a line segment complemented by pressure charts or field logs. Another example might include a purchase order to a pipe mill with pipe specifications verified by a metallurgical test of a coupon pulled from the same pipe segment. In general, the only acceptable use of an affidavit would be as a complementary document, prepared and signed at the time of the test or inspection by an individual who would have reason to be familiar with the test or inspection.

Complete records are those in which the record is finalized as evidenced by a signature, date or other appropriate marking. For example, a complete pressure testing record should identify a specific segment of pipe, who conducted the test, the duration of the test, the test medium, temperatures, accurate pressure readings, and elevation information as applicable. An incomplete record might reflect that the pressure test was initiated, failed and restarted without conclusive indication of a successful test. A record that cannot be specifically linked to an individual pipe segment is not a complete record for that segment. Incomplete or partial records are not an adequate basis for establishing MAOP or MOP. If records are unknown or unknowable, a more conservative approach is indicated.

PHMSA is aware that other types of records may be acceptable and that certain state programs may have additional requirements. Operators should ensure all records establish confidence in the validity of the records. If a document and records search, review, and verification cannot be satisfactorily completed to meet the need for traceable, verifiable, and complete records, the operator may need to conduct other activities such as in-situ examination, measuring yield and tensile strength, pressure testing, and nondestructive testing or otherwise verify the characteristics of the pipeline to support a MAOP or MOP determination.

PHMSA is supportive of the use of alternative technologies to verify pipe characteristics. Owners and operators seeking to use alternative or non-traditional technologies in the determination of MAOP or MOP, or to meet other regulatory requirements, should first discuss the proposed approach with the appropriate state or Federal regulatory agencies to determine its acceptability under regulatory requirements.

PHMSA will issue more direction regarding how operators will be required to bring into compliance gas and hazardous liquid pipelines without verifiable records for the entire mileage of the pipeline. Further details will also be provided on the manner in which PHMSA intends to require operators to reestablish MAOP as discussed in Section 23(a) of the Act.

Finally, PHMSA notes that on September 26, 2011, NTSB issued Recommendation P–11–14: Eliminating Grandfather Clause. Section 192.619(a)(3) allows gas transmission operators to establish MAOP of pipe installed before July 1, 1970, by use of records noting the highest actual operating pressure to which the segment was subjected during the five years preceding July 1, 1970. NTSB Recommendation P–11–14 requests that PHMSA delete § 192.619(a)(3), also known as the ''grandfather clause,'' and require gas transmission pipeline operators to reestablish MAOP using hydrostatic pressure testing. PHMSA reminds operators that this recommendation will be acted upon following the collection of data, including information from the 2013 Gas Transmission and Gathering Pipeline Systems Annual Report, which will allow PHMSA to determine the impact of the requested change on the public and industry in conformance with our statutory obligations.

Issued in Washington, DC, on May 1, 2012.

Alan K. Mayberry,

Deputy Associate Administrator for Field Operations.

[FR Doc. 2012–10866 Filed 5–4–12; 8:45 am]

BILLING CODE 4910–60–P

DEPARTMENT OF TRANSPORTATION

Research & Innovative Technology Administration

[Docket ID Number RITA 2008–0002]

Agency Information Collection; Activity Under OMB Review; Reporting Required for International Civil Aviation Organization (ICAO)

AGENCY: Research & Innovative Technology Administration (RITA), Bureau of Transportation Statistics (BTS), DOT.

ACTION: Notice.

SUMMARY: In compliance with the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*), this notice announces that the Information Collection Request (ICR) abstracted below has been forwarded to the Office of Management and Budget (OMB) for extension of currently approved collections. The ICR describes the nature of the information collection and its expected burden. The **Federal Register** Notice with a 60-day comment period soliciting comments on the following collection of information was published on February 29, 2012 (77 FR 12364). No comments were received.

DATES: Written comments should be submitted by June 6, 2012.

FOR FURTHER INFORMATION CONTACT: Jeff Gorham, Office of Airline Information, RTS–42, Room E34, RITA, BTS, 1200 New Jersey Avenue SE., Washington, DC 20590–0001, Telephone Number (202) 366–4406, Fax Number (202) 366–3383 or Email *jeff.gorham@dot.gov.*

Comments: Send comments to the Office of Information and Regulatory Affairs, Office of Management and Budget, 725–17th Street NW., Washington, DC 20503, Attention: RITA/BTS Desk Officer.

SUPPLEMENTARY INFORMATION:

OMB Approval No.: 2138–0039.

Title: Reporting Required for International Civil Aviation Organization (ICAO).

Form No.: BTS Form EF.

Type of Review: Extension of a currently approved collection.

Respondents: Large certificated air carriers.

Number of Respondents: 40.

Number of Responses: 40.

Total Annual Burden: 26 hours.

Needs and Uses: As a party to the Convention on International Civil Aviation (Treaty), the United States is obligated to provide ICAO with financial and statistical data on operations of U.S. air carriers. Over 99% of the data filed with ICAO is extracted from the air carriers' Form 41 submissions to BTS. BTS Form EF is the means by which BTS supplies the remaining 1% of the air carrier data to ICAO.

The Confidential Information Protection and Statistical Efficiency Act of 2002 (44 U.S.C. 3501), requires a statistical agency to clearly identify information it collects for non-statistical purposes. BTS hereby notifies the respondents and the public that BTS uses the information it collects under this OMB approval for non-statistical purposes including, but not limited to, publication of both Respondent's identity and its data, submission of the information to agencies outside BTS for review, analysis and possible use in regulatory and other administrative matters.

Comments are invited on: Whether the proposed collection of information is necessary for the proper performance of the functions of the Department concerning consumer protection. Comments should address whether the information will have practical utility; the accuracy of the Department's estimate of the burden of the proposed information collection; ways to enhance the quality, utility and clarity of the information to be collected; and ways to minimize the burden of the collection of information on respondents, including the use of automated collection techniques or other forms of information technology.

Issued in Washington, DC on May 1, 2012.

Pat Hu,

Director, Bureau of Transportation Statistics, Research and Innovative Technology Administration.

[FR Doc. 2012–10909 Filed 5–4–12; 8:45 am]

BILLING CODE 4910–HY–P

DEPARTMENT OF TRANSPORTATION

Research & Innovative Technology Administration

[Docket ID Number RITA 2008–0002]

Agency Information Collection; Activity Under OMB Review; Submission of Audit Reports—Part 248

AGENCY: Research & Innovative Technology Administration (RITA), Bureau of Transportation Statistics (BTS), DOT.

ACTION: Notice.

SUMMARY: In compliance with the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*), this notice announces that the Information Collection Request (ICR) abstracted below has been forwarded to the Office of Management and Budget (OMB) for extension of currently approved collections. The ICR describes the nature of the information collection and its expected burden. The **Federal Register** Notice with a 60-day comment period soliciting comments on the following collection of information was published on February 29, 2012 (77 FR 12365). No comments were received.

DATES: Written comments should be submitted by June 6, 2012.

FOR FURTHER INFORMATION CONTACT: Jeff Gorham, Office of Airline Information, RTS–42, Room E34, RITA, BTS, 1200 New Jersey Avenue SE., Washington,

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Xcel Energy
Docket No.: G002/M-17-787
Response To: MN Department of Commerce Information Request No. 35
Requestors: Dorothy Morrissey, Danielle Winner
Date Received: March 26, 2018

Question:

Topic: DIMP Quantitative Risk Assessment – Problematic Steel Project
Reference(s): Attachment D2(a)

A. On Page 2, it states "lower risk pipe segments in the same block as higher risk segments may be done as part of the same project to minimize disruption to the local community." Please identify the cost amount of each DIMP pipeline replacement project attributed to replacement of low-risk-scored pipeline and/or services that is included in GUIC recovery request.

B. Pages 5: Please explain how the demarcation values for the three risk level ranges were decided.

C. Pages 6-7, reports that a Manufacturing/Construction Defect Risk Factor score of "2" is assigned if pipeline documentation of pressure test is not Traceable, Verifiable and Complete (TVC). Of the jurisdictional operating system subject to 49 CFR 192.619 requirement, please provide each of the following:

(1) the percentage of the pipeline system that lacks the required TVC documentation of pressure test; Please identify the feasible remedies and their relative costs that are available to the particular pipeline segments lacking needed documentation;

(2) the vintage of newest pipeline that lacks required TVC documentation of pressure test and explain why this segment lacks such documentation.

D. Page 8, regarding the risk matrix, Likelihood of Failure scenarios, specifically the baseline score of "3" assigned to the third-described conditions combination "Mechanical Coupled OR No TVC Test to criteria AND

Corrosion/Leakage/3rd Party." It appears the base line score, given the multiple condition inclusions, could range from a minimum of 3 to a maximum of 5. If this is correct, how was the assigned value of 3 decided for this combination; and how does use of the fixed value of 3 impact the relative accuracy of quantified risk assessment outcomes and project priority based decisions?

Response:

A. Attachment A to this response shows the capital cost for each DIMP pipeline replacement project attributed to replacement of low-risk-scored pipeline and/or services in order to minimize disruption to the local community.

B. For the Likelihood of Failure, the demarcation for the top three risk levels is the pressure of the system they are operating in; with higher pressures resulting in a higher Likelihood of Failure Score.

C. 1) Approximately 53 percent of the Intermediate Pressure pipeline system lacks traceable, verifiable and complete (TVC) documentation of a pressure test. Feasible remedies for segments lacking documentation include pressure testing to a pressure that supports the Maximum Allowable Operating Pressure (MAOP) or replacement of the segment. For some segments, due to the presence of vintage mechanical couplings, there are no acceptable alternatives remedies other than replacement. Pressure test costs are generally expected to range from $150,000 per mile to $2.0 million per mile depending on pipe size and project location. Intermediate Pressure replacement costs are generally expected to range from $3.0 million per mile to $8 million per mile depending on pipe size and project location.

(2) The newest pipeline that lacks the required TVC documentation of pressure test is a segment of the Highway 96 Line installed in 1982. The pressure is not verifiable due to the fact that there are no pressure test charts in the project documentation files.

D. The likelihood of failure score ranges from 0 to 5 based upon the relative risk scores that Company subject matter experts placed on five different combinations of risk factors. The Likelihood of Failure score considers the status of three risk conditions; these include (1) whether the pipeline is mechanically coupled, (2) whether TVC records exist of a satisfactory post construction pressure test, and (3) whether there is a history of corrosion, leakage, or third-party damage. The Likelihood of Failure score of 3 was given to the pipeline condition where the presence of <u>either</u> mechanical couplings or No TVC test <u>in combination with</u> a history of corrosion, leakage or third-party damage. The score of 3 was assigned as a relative score between conditions considered to be a greater Likelihood of Failure (conditions scoring 4 and 5) and conditions considered to be a lesser Likelihood of Failure (conditions scoring 1 and 2).

Preparer: Eric Kirkpatrick
Title: Director
Department: Gas Engineering & Project Management
Telephone: 303-571-3223
Date: April 5, 2018

Northern States Power Company

Docket No. G002/M-17-787
DOC Information Request No. 35
Attachment A - Page 1 of 1

Capital Costs - DIMP Pipeline Replacement Projects
Replacement of Low-Risk-Scored Pipeline and/or Services

Project Name	**Total Install Footage**	**Footage of Low Risk**	**Cost of Low Risk Segments**
FARIBAULT 109442 - IRVING AVE	4,200	400	$14,968
RED WING 189336 - REDING AVE	4,330	300	$11,226
WINONA 98082 -CONRAD DR	5,300	300	$11,226
WINONA 106932 - 44TH AVE	4,300	50	$1,871
WINONA 98162 - W 9TH ST	3,400	350	$13,097
WINONA 98341 - E 8TH ST	4,000	200	$7,484
NORTHFIELD - 321 ST W	3,950	50	$1,871
RED WING - CENTRAL PARK ST	1,600	30	$1,123
WINONA - SUNSET DR	15,050	225	$8,420
MAPLEWOOD- MARNIE & HIGHWOOD	13,300	375	$14,033

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Xcel Energy
Docket No.: G002/M-17-787
Response To: MN Department of Commerce Information Request No. 24
Requestors: Dorothy Morrissey, Danielle Winner
Date Received: February 7, 2018

Question:

Topic: MAOP benefit
Reference(s): Attachment C1(e)

The projects East County Line Renewal (SSP to RR) and County Road B (NSP to Rice) both note that a benefit of each project is "MAOP established through uprate."

A. For each project, please explain the benefit "MAOP established through uprate."

B. Please explain whether these existing pipeline segments being replaced have uncertain/unknown/or unproven MAOPs.

C. Please explain whether the replacement pipeline segments expected MAOPs will support future customer or sales growth that cannot be served through, or is limited by, the existing MAOP status of these pipeline segments.

Response:

A. The benefit of both projects is to ensure that the maximum allowable operating pressure (MAOP) of the pipeline is confirmed by a traceable, verifiable and complete pressure test record that substantiates that a completed pressure test was conducted at a pressure greater than the MAOP of the pipeline by a safety factor of 1.25 or the factor established in 49CFR Part 192.619(a)(2), whichever is greater. Both pipelines have MAOPs based on pressure uprates that do not satisfy this criteria, and the benefit of both projects is that the new pipelines will.

B. Both pipelines were installed between 1957 and 1959 prior to the establishment of federal code requirements for gas pipeline safety under 49CFR Part 192 in 1970. The existing record evidence required to support MAOP are not certain, as they do not meet the traceable, verifiable and complete criteria set forth in PHMSA Advisory Bulletin ADB-11-01 in January of 2011. In addition, neither pipeline has a pressure test that achieves a safety factor of 1.25 or the factor established in 49CFR Part 192.619(a)(2), whichever is greater.

C. Each pipe segment will be designed and pressure tested to an MAOP of 740 psig as a common and prudent engineering practice that establishes a greater factor of safety between the pressure test and normal operating pressures. Elevating the level of the pressure test is easily achieved during the hydrotest of the pipeline by pumping in a small incremental amount of water during the test. The East County Line will continue to operate at a normal operating pressure of 220 psig, and the County Road B Line will continue to operate at a normal operating pressure of 175 psig due to limitations of interconnected pipe systems. Because the areas served by these pipelines are fully populated, they are expected to be able to support the long-term needs of the community at the existing operating pressures.

Preparer:	Eric Kirkpatrick
Title:	Director
Department:	Gas Engineering & Project Management
Telephone:	(303) 571-3223
Date:	February 20, 2018

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Xcel Energy
Docket No.: G002/M-17-787
Response To: MN Department of Commerce Information Request No. 59
Requestor: Dorothy Morrissey, Danielle Winner
Date Received: April 9, 2018

Question:

Topic: DIMP – Intermediate Pressure Pipeline Assessments
Reference(s): DOC IR #35

Request:

Response to Part C of DOC IR No. 35: Please provide the total number of miles of the Intermediate pressure pipeline system that makes up the 53 percent lacking traceable, verifiable and complete documentation of a pressure test.

Response:

There are 40.5 miles (53 percent) of the intermediate pressure pipeline system that lack traceable, verifiable and complete documentation of a pressure test in the Metro area. The Metro area intermediate pressure pipeline system has been the Company's central focus due to pipeline age and higher population density. The Company has an additional 207 miles of intermediate pressure pipelines in outstate Minnesota that have not yet been evaluated to determine if they have pressure test information that is traceable, verifiable, and complete.

Preparer: Eric Kirkpatrick
Title: Director
Department: Gas Engineering & Project Management
Telephone: 303-571-3223
Date: April 16, 2018

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Xcel Energy
Docket No.: G002/M-17-787
Response To: MN Department of Commerce Information Request No. 17
Requestors: Dorothy Morrissey, Danielle Winner
Date Received: January 30, 2018

Question:

Topic: Transmission Pipeline Assessments
Reference(s): Attachment C, p. 7

Regarding the Island Line (South of River) ILI assessment project of 1.9 mile segment installed in 1952:

A. Please identify the service life of this pipe segment;

B. Please explain the economic analysis conducted that supports expending funds to allow for "proving" this 65-year old pipe and for preparations necessary to use ILI technology assessments, over investing in pipe replacement; and

C. Please support the justification for ILI assessment project expenditures given that the variance explanation statement on page 19 of Attachment C indicates the Island South pipeline is being scoped for replacement.

Response:

A. The Company is currently approved to use an average service life of 75 years for the purpose of depreciating gas transmission mains. However, the Company does not have a defined service life for these assets. The actual service life of a given asset can vary significantly based on factors including but not limited to, original installation practices, maintenance history, cathodic protection, and coating condition.

B. In-line inspection (ILI) "proving tools" are designed to traverse pipelines that have not been modified to be assessable by ILI tools and are utilized to identify restrictions though which a "smart pig" would not be able to pass. The Company utilized a "proving pig" in 2017 to determine the extent of modifications that would be necessary to make the remaining 1952 portion of the Island Line South assessable by ILI tools. No restrictions were identified that might prohibit a full ILI assessment. As such, the Company plans to proceed with a full ILI assessment of the pipeline in 2018. This assessment will be utilized to verify proper installation of the new pipeline construction and provide a condition assessment of the 1952 portion of the line. Based on the results of the ILI assessment, the Company will either repair or proceed with replacement of the 1952 portion of the line.

The total cost to complete ILI assessment of the pipeline is estimated at \$0.6 million. Approximately 1.1 miles of the original 1952 pipe remains in service. The estimated unit cost for replacement of this pipe is \$1,160 per foot for a total cost of \$6.7 million.

C. In 2017 a portion of the 1.5 miles referenced on page 19 of Attachment C was replaced to reduce risks of failure that may occur with Union Pacific Railroad trestle work using pile driving equipment within 18 inches of the Company's pipelines. The Company originally scoped the project to account for the risk that the remaining 1.1 miles may not be assessable by ILI tools and may not be feasible to modify. The Company plans to proceed with a full ILI assessment of the pipeline in 2018. Based on the results of the ILI assessment the Company will either repair or proceed with replacement of the 1952 portion of the line.

Preparer:	Ray Gardner
Title:	Director
Department:	Integrity Management Programs
Telephone:	303-571-3904
Date:	February 9, 2018

From: Kirschner, Brandon M
To: Morrissey, Dorothy (COMM)
Cc: Peppin, Michael A; Peterson, Lisa R; Liberkowski, Amy A
Subject: Xcel Gas - Island Line
Date: Thursday, April 05, 2018 2:32:02 PM

Dorothy,

With Lisa Peterson out on vacation, Michael Peppin forwarded your questions about our Island Line transmission project on to me. I have been working closely with our GUIC docket, so I am happy to provide some additional clarification.

The entire length of our Island Line is approximately 1.9 miles. This includes approximately 0.4 miles of the line that were replaced in 2016 in order to make the line accessible to in-line inspection equipment. The 7,900 feet referenced in Attachment B1(f) and the 1.5 miles referenced in Attachment B both represented the total scope of the Island Line Project remaining to be completed in 2017 and beyond. These amounts excluded the 0.4 miles already completed.

In our response to DOC-017 in the current docket, the 1.1 miles of pipeline mentioned was the part of the project that was slated to be worked on in 2018, while the 1.5 miles mentioned was the total remaining project for 2017 and 2018. An additional 0.34 miles (1800 feet) of pipeline was replaced in 2017. Rerouting of the line during this part of the project added approximately 300 feet to the total length of the line. The remaining 1.15 miles (6100 feet) of pipeline is slated to be replaced in 2018. With the additional 300 feet added in 2017, the total Island Line will be closer to 2.0 miles rather than 1.9 miles.

I hope this helps answer your questions surrounding the Island Line project. If you have any additional questions while Lisa is out, feel free to contact Mike Peppin or myself. Thanks!

Brandon Kirschner
Xcel Energy | Responsible By Nature
Regulatory Policy Specialist
414 Nicollet Mall, 401-7, Minneapolis, MN 55401
P: 612.215.5361 F: 612.330.7601
E: Brandon.M.Kirschner@xcelenergy.com

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Xcel Energy
Docket No.: G002/M-17-787
Response To: MN Department of Commerce Information Request No. 33
Requestors: Dorothy Morrissey, Danielle Winner
Date Received: March 20, 2018

Question:

Topic: DIMP Project – Intermediate Pressure Line Assessments
Reference(s): Attachment D, p. 9

Please break down the 2018 overall $19.82 million capital and $1.03 million O&M expenditures among the IP Line Assessment projects tabled on page 9 of Attachment D.

Response:

A breakdown of the 2018 overall $19.82 million capital and $1.03 million O&M expenditures among the IP Line Assessment projects is provided in the table below. Project detail for each DIMP – Intermediate Pressure Line Assessment Project is included in Petition Attachment D1(e).

IP Line Assessments (In Millions - $M)		As Filed, Docket 17-0787		
Program	Sub-Project	Program Total	GUIC Rider Recoverable Total	Non-GUIC Recoverable Total*
DIMP	Langdon Line	$ 12.5	$ 11.8	$ 0.7
	Colby Lake Lateral	$ 4.8	$ 3.4	$ 1.4
	H005 - Lexington to Snelling	$ 4.9	$ 4.6	$ 0.3
	IP Line Assessments - Total Capital	**$ 22.2**	**$ 19.8**	**$ 2.4**
	H08 - Lake Elmo 1A TBS	$ 0.2	$ 0.2	$ -
	T009 - Cottage Grove TBS	$ 0.2	$ 0.2	$ -
	Montreal Line North	$ 0.63	$ 0.63	$ -
	IP Line Assessments - Total O&M	**$ 1.03**	**$ 1.03**	**$ -**

**Note – Non-GUIC recoverable costs include betterment, internal labor, and Engineering and Supervision (E&S) overheads associated with internal labor.*

Preparer: Ray Gardner
Title: Director
Department: Integrity Management Programs
Telephone: 303-571-3904
Date: March 30, 2018

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Xcel Energy
Docket No.: G002/M-17-787
Response To: MN Department of Commerce Information Request No. 17
Requestors: Dorothy Morrissey, Danielle Winner
Date Received: January 30, 2018

Question:

Topic: Transmission Pipeline Assessments
Reference(s): Attachment C, p. 7

Regarding the Island Line (South of River) ILI assessment project of 1.9 mile segment installed in 1952:

A. Please identify the service life of this pipe segment;

B. Please explain the economic analysis conducted that supports expending funds to allow for "proving" this 65-year old pipe and for preparations necessary to use ILI technology assessments, over investing in pipe replacement; and

C. Please support the justification for ILI assessment project expenditures given that the variance explanation statement on page 19 of Attachment C indicates the Island South pipeline is being scoped for replacement.

Response:

A. The Company is currently approved to use an average service life of 75 years for the purpose of depreciating gas transmission mains. However, the Company does not have a defined service life for these assets. The actual service life of a given asset can vary significantly based on factors including but not limited to, original installation practices, maintenance history, cathodic protection, and coating condition.

B. In-line inspection (ILI) "proving tools" are designed to traverse pipelines that have not been modified to be assessable by ILI tools and are utilized to identify restrictions though which a "smart pig" would not be able to pass. The Company utilized a "proving pig" in 2017 to determine the extent of modifications that would be necessary to make the remaining 1952 portion of the Island Line South assessable by ILI tools. No restrictions were identified that might prohibit a full ILI assessment. As such, the Company plans to proceed with a full ILI assessment of the pipeline in 2018. This assessment will be utilized to verify proper installation of the new pipeline construction and provide a condition assessment of the 1952 portion of the line. Based on the results of the ILI assessment, the Company will either repair or proceed with replacement of the 1952 portion of the line.

The total cost to complete ILI assessment of the pipeline is estimated at $0.6 million. Approximately 1.1 miles of the original 1952 pipe remains in service. The estimated unit cost for replacement of this pipe is $1,160 per foot for a total cost of $6.7 million.

C. In 2017 a portion of the 1.5 miles referenced on page 19 of Attachment C was replaced to reduce risks of failure that may occur with Union Pacific Railroad trestle work using pile driving equipment within 18 inches of the Company's pipelines. The Company originally scoped the project to account for the risk that the remaining 1.1 miles may not be assessable by ILI tools and may not be feasible to modify. The Company plans to proceed with a full ILI assessment of the pipeline in 2018. Based on the results of the ILI assessment the Company will either repair or proceed with replacement of the 1952 portion of the line.

Preparer: Ray Gardner
Title: Director
Department: Integrity Management Programs
Telephone: 303-571-3904
Date: February 9, 2018

From:	Kirschner, Brandon M
To:	Morrissey, Dorothy (COMM)
Cc:	Peppin, Michael A; Peterson, Lisa R; Liberkowski, Amy A
Subject:	Xcel Gas - Island Line
Date:	Thursday, April 05, 2018 2:32:02 PM

Dorothy,

With Lisa Peterson out on vacation, Michael Peppin forwarded your questions about our Island Line transmission project on to me. I have been working closely with our GUIC docket, so I am happy to provide some additional clarification.

The entire length of our Island Line is approximately 1.9 miles. This includes approximately 0.4 miles of the line that were replaced in 2016 in order to make the line accessible to in-line inspection equipment. The 7,900 feet referenced in Attachment B1(f) and the 1.5 miles referenced in Attachment B both represented the total scope of the Island Line Project remaining to be completed in 2017 and beyond. These amounts excluded the 0.4 miles already completed.

In our response to DOC-017 in the current docket, the 1.1 miles of pipeline mentioned was the part of the project that was slated to be worked on in 2018, while the 1.5 miles mentioned was the total remaining project for 2017 and 2018. An additional 0.34 miles (1800 feet) of pipeline was replaced in 2017. Rerouting of the line during this part of the project added approximately 300 feet to the total length of the line. The remaining 1.15 miles (6100 feet) of pipeline is slated to be replaced in 2018. With the additional 300 feet added in 2017, the total Island Line will be closer to 2.0 miles rather than 1.9 miles.

I hope this helps answer your questions surrounding the Island Line project. If you have any additional questions while Lisa is out, feel free to contact Mike Peppin or myself. Thanks!

Brandon Kirschner
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Xcel Energy
Docket No.: G002/M-17-787
Response To: MN Department of Commerce Information Request No. 33
Requestors: Dorothy Morrissey, Danielle Winner
Date Received: March 20, 2018

Question:

Topic: DIMP Project – Intermediate Pressure Line Assessments
Reference(s): Attachment D, p. 9

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	H005 - Lexington to Snelling	$ 4.9	$ 4.6	$ 0.3
	IP Line Assessments - Total Capital	**$ 22.2**	**$ 19.8**	**$ 2.4**
	H08 - Lake Elmo 1A TBS	$ 0.2	$ 0.2	$ -
	T009 - Cottage Grove TBS	$ 0.2	$ 0.2	$ -
	Montreal Line North	$ 0.63	$ 0.63	$ -
	IP Line Assessments - Total O&M	**$ 1.03**	**$ 1.03**	**$ -**

**Note – Non-GUIC recoverable costs include betterment, internal labor, and Engineering and Supervision (E&S) overheads associated with internal labor.*

Preparer: Ray Gardner
Title: Director
Department: Integrity Management Programs
Telephone: 303-571-3904
Date: March 30, 2018

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Xcel Energy
Docket No.: G002/M-17-787
Response To: MN Department of Commerce Information Request No. 31
Requestors: Dorothy Morrissey, Danielle Winner
Date Received: March 20, 2018

Question:

Topic: DIMP Project – Intermediate Pressure Line Assessments
Reference(s): Attachment D, p. 9; Langdon Line Replacement

A. Please identify the amount of the estimated project's costs attributed to enhanced features and/or capabilities that the 12" replacement pipeline will have over the existing pipeline.

B. Please explain how replacement of the 6-inch and 8-inch pipe supports additional reliability of the Metro area bulk system.

C. Regarding reliability, please discuss the Metro area bulk system failures or near failures that this designed pipe replacement project will diminish.

D. Please discuss whether modern day 8-inch pipe would be adequate for this project; if not please explain why; if so, please identify the cost differential between use of 12-inch pipe over 8-inch pipe for this portion of the gas operating system.

Response:

A. The estimated cost difference between replacing this segment of the Langdon pipeline with 12-inch instead of matching the existing diameters segment by segment is $4.4 million. However, this cost comes with integrity and safety benefits. Replacing the line with one continuous diameter will allow In-Line-Inspection (ILI) to be run on the entire Langdon pipeline. ILI will allow the Company to inspect the line more efficiently to ensure the integrity and safety of the pipeline. The favorable impact of associated system reliability is an additional benefit but not the basis for selection of pipe size.

B. Replacing the 6-inch and 8-inch pipe with a continuous 12-inch diameter pipe will allow ILI to be used on the entire line. ILI will enable the Company to identify and remediate flaws or pipe deterioration in advance of a pipeline failure, helping to ensure that the gas system is safe and reliable.

C. The Company recorded 17 pipeline leak repairs on the Metro Area Bulk system from 2012 through 2017. Six of the leaks were recorded as being on the main. The Langdon pipeline itself has a history of third-party damage and corrosion. Replacement of the line will eliminate pipe that has mechanical couplings, lacks records of a post construction pressure test, and has a history of corrosion and third-party damage, as well as allow for more efficient inspections via ILI.

D. The cost difference between using 8-inch diameter pipe and 12-inch diameter pipe is estimated to be approximately $3.6 Million. While 8-inch diameter pipe would be adequate for the capacity needs of the pipeline, the installation of 12-inch pipe ensures a continuous diameter for the entire Langdon pipeline. This will allow for ILI to be used on the entire line, which helps ensure gas system safety and reliability.

Preparer: Eric Kirkpatrick
Title: Director
Department: Gas Engineering & Project Management
Telephone: 303-571-3223
Date: March 30, 2018

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☐ **Public Document – Not Public Data Has Been Excised**
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Xcel Energy
Docket No.: G002/M-17-787
Response To: MN Department of Commerce Information Request No. 32
Requestors: Dorothy Morrissey, Danielle Winner
Date Received: March 20, 2018

<u>Question:</u>

Topic: DIMP Project – Intermediate Pressure Line Assessments
Reference(s): Attachment D, pp. 10-11; Lexington to Snelling pipeline replacement

A. Please explain and distinguish the characteristics of distribution pipelines for which alternate safety inspection methods must be used and conducted on the limited segments that cannot be inspected by using the external corrosion direct assessment (ECDA) method, in order to satisfy regulatory requirements.

B. Please provide the total amount of base rate cost savings expected, and identify the plant equipment in rates that will be eliminated, as a result of removing numerous services served directly off the high pressure system.

C. Please indicate if the H005 pipeline replacement will continue to have some services directly connected to it, and if so, explain why.

D. Please identify the federal or state agency directive that requires services to not be connected to distribution pipeline having characteristics of the replaced H005 pipeline.

E. Please identify the portion of this project's costs included in the GUIC recovery request attributed to the extension of the nearby 60 psi system being undertaken in order to facilitate transfer of services.

<u>Response:</u>

A. In order to perform in-line-inspection (ILI) a pipeline must be constructed in a manner that allows for passage of the ILI tool. These construction limitations include the need for long radius elbows (a steel fitting that turns the pipeline) and typically constructed of one diameter. ILI tools are designed for passage inside of the pipe. For existing pipelines that are not constructed in a manner that will allow ILI, the only integrity inspection technique available is ECDA. ECDA is only able to detect locations where external corrosion may be impacting the pipeline.

By contrast, ILI tools allow the Company to inspect lines for multiple threats that include external corrosion, internal corrosion, manufacturing defects, material defects, construction defects and third party damage. Therefore, to reduce the risk from all threat types, ILI is the preferred inspection method. In order to reduce the risk associated with operating a large diameter, high-pressure distribution line in a highly populated area, the Company will be constructing the new pipeline in a manner that allows for ILI.

B. Removing services from the larger diameter, high-pressure pipeline and placing them on the lower-pressure plastic system will not result in rate base cost savings or elimination of plant equipment. In constructing the new pipeline, the Company will be removing the services from the large diameter, high-pressure pipeline in order to allow ILI to be performed without disrupting service to large volume commercial customers. Approximately 20 services will be relocated to a new 2-inch and 4-inch plastic main.

C. The new 8-inch and 12-inch steel high-pressure pipeline will not have services directly connected to it. This is being done in order to allow the pipeline to be inspected with ILI technology.

D. There are no federal or state directives that require services not be installed to the new 8-inch and 12-inch steel high-pressure pipeline. The Company has opted to not directly connect services to the pipeline in order to maintain the ability to inspect the line with ILI technology.

E. The portion of this project's capital costs included in the GUIC recovery request attributed to the extension of the nearby 60 psi system being undertaken in order to facilitate transfer of services is estimated to be $420,000.

Preparer:	Eric Kirkpatrick
Title:	Director
Department:	Gas Engineering & Project Management
Telephone:	303-571-3223
Date:	March 30, 2018

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Xcel Energy
Docket No.: G002/M-17-787
Response To: MN Department of Commerce Information Request No. 49
Requestor: Danielle Winner, Dorothy Morrissey
Date Received: April 2, 2018

Question:

Topic: Contracts/Work Orders/Invoices
Reference(s): Xcel Gas Initial Filing Attachments C and D

Request:

Please provide all contracts, work orders, and invoices from 2017 and 2018 for the following TIMP Projects:

A. 11649521 (Transmission Pipeline Assessments – Capital)
B. 11649797 (Transmission Pipeline Assessments – Capital)
C. 34000342 (Transmission Pipeline Assessments – Capital)
D. 11984286 (Transmission Pipeline Assessments – O&M)
E. 11503515 (ASVs and RCVs – Capital)
F. 11651650 (Programmatic Replacement and MAOP Remediation – Capital)
G. 11810375 (Programmatic Replacement and MAOP Remediation – Capital)
H. 34003261 (Programmatic Replacement and MAOP Remediation – Capital)

Please provide all contracts, work orders, and invoices from 2017 and 2018 for the following DIMP Projects:

A. 11649522 (Poor Performing Main Replacements – Capital)
B. 12173831 (Poor Performing Main Replacements – Capital)
C. 34000462 (Poor Performing Main Replacements – Capital)
D. 11649766 (Poor Performing Service Replacements – Capital)
E. 12173830 (Poor Performing Service Replacements – Capital)
F. 11980562 (Intermediate Pressure Line Assessments – Capital)
G. 11984278 (Intermediate Pressure Line Assessments – O&M)

H. 11649520 (Distribution Valve Replacement Project – Capital)
I. 12173704 (Distribution Valve Replacement Project – Capital)
J. 11984282 (Sewer and Gas Line Conflict Investigation- O&M)
K. 12173409 (Federal Code Mitigation- Capital)

Response:

The Company has attached all actual work order charges and contracts from 2017 for all of its GUIC projects as Attachment A and Attachment B to this response, respectively. Due to the volume of invoices related to these contracts and work orders, we have not included invoices as part of this response. Doing so would entail the assembly of many thousands of documents, and we estimate that this process would take at least a month to complete. In addition, the Company is not providing 2018 work order information at this time due to the limited scope of work completed to date related to its GUIC programs. The set of contracts provided for 2017 continue to govern the 2018 scope of work, unless otherwise stated.

Included in Attachment A is a detailed summary of all GUIC capital and O&M work order charges from 2017. Therein, the Company has specified charges corresponding to all work invoiced from and paid to contractors (see column D of "Capital Data" and "O&M Data" tabs) on GUIC-related projects. These charges are governed by the contracts provided in Attachment B. Individual invoiced amounts and corresponding invoice reference and purchase numbers are found on the respective "COV Invoice/SAP PO" tabs for both capital and O&M in Attachment A, which is provided in live Excel spreadsheet format.

The Company can readily provide specific invoices for invoice and purchase numbers identified by the Department using the information provided in this response. As another alternative, the Company would be happy to arrange an onsite inspection of the invoices with the Department and produce documents requested as a result of the inspection.

Attachments A and B are marked as "Not-Public" because they include confidential contract and pricing terms and vendor detail considered to be trade secret data as defined by Minn. Stat. § 13.37(1)(b). This information has independent economic value, from not being generally known to, and not being readily ascertainable by other parties, who could obtain economic value from its disclosure or use. The disclosure of this information could adversely impact contract negotiations, potentially increasing costs for these services for our customers. Thus, Xcel Energy maintains this information as a trade secret pursuant to Minn. Rule 7829.0500.

Attachment B is marked as "Not-Public" in its entirety. Pursuant to Minn. R. 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material:** Attachment B is a PDF collection of contracts between the Company and its vendors for 2017 work on TIMP and DIMP projects listed in this inquiry.
2. **Authors:** The contracts included in the Attachment B collection were drafted by Xcel Energy Services legal and sourcing personnel.
3. **Importance:** We protect these contract terms, as disclosure can adversely affect negotiations and increase costs for services.
4. **Date the Information was Prepared:** The Attachment B contract collection was prepared for this response April 2018.

Preparer:	Andrew Sudbury
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Department:	Gas System Strategy and Bus Ops XS
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Date:	April 19, 2018

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Xcel Energy
Docket No.: G002/M-17-787
Response To: MN Department of Commerce Information Request No. 62
Requestor: Dorothy Morrissey, Danielle Winner
Date Received: May 8, 2018

Question:

Topic: Contracts, Work Orders, Invoices
Reference(s): Xcel Trade Secret response to Department IR 49
Xcel March 27 Supplemental Filing Attach E
Xcel Initial Filing, Attach D, page 4.

In response to the Department's IR 49, the Company provided 14 contracts that govern specific parent projects for the years 2017 and 2018. However, all contracts provided have start dates prior to 2016, with some as far back as 2008.

A. Please describe, in as much detail as possible, the Company's process for renewing contracts, including how this process interacts with competitive bidding processes.

B. Please provide any contract renewal documentation related to the contracts provided in response to IR 49.

All contracts provided to the Department list at least one of Xcel's executing affiliates as "NSP-MN," which includes MN, ND, and SD. However, 12 of the 14 contracts provided also include either NSP-WI, PSCo, and/or SW PSC-NM. Further, 5 contracts contain a geographic scope of work that includes both MN and other states, and 8 contracts contain pricing schedules that include both MN and other states.

C. Please describe, in as much detail as possible, how the Company parses out MN-specific work in the contracts that govern multiple jurisdictions.

D. If any sub-contracts exist for purposes of designating MN-specific work, please provide those sub-contracts.

[TRADE SECRET BEGINS

TRADE SECRET ENDS]

E. Please explain why there are more vendors in the dataset than in the contracts provided to the Department.

F. Please also explain why the contracts provided to the Department contain contract, master agreement, and work order numbers that do not match those recorded in the dataset.

G. How can the "Outside Vendor Contract" data be traced back to a particular contract?

[TRADE SECRET BEGINS

TRADE SECRET ENDS]

H. Please confirm the Department's understanding of 2017 capital expenditures, or provide an alternative explanation reconciling these different totals found in the dataset and reported in the Supplemental Filing.

I. Please also clarify which categories and charges in the Capital Data dataset are considered "Materials, Transportation, Construction Overhead, and Other," and which are considered "Internal Labor."

Response:

See Appendix A for a list of attachments included with this response.

A. The Company's process for renewing contracts is governed by our "Procurement of Normal Goods and Services" policy. Please reference the Change Orders or Amendments section on Page 10 of Attachment A to this response for the portion of the policy that governs the change order process, which is used to amend or extend a contract term.

B. Please reference Attachment B1 to this response for contract renewal documentation for the contracts provided in our response to Information Request DOC-49. Change orders, the document used for contract renewals, are only completed when a change is made to a contract. As such not all the provided contracts have a corresponding change order. The Company has additionally provided Attachment B2, "Supply Chain Operating Requirements (SCOR)", which describes the change order process in more detail (See Section 10, Pages 77-79).

C. For contracts that govern work in multiple jurisdictions, the Company utilizes jurisdictional-specific work orders to track costs for each jurisdiction. When the Company is designing, estimating, and executing work each jurisdictional-specific work order is used for the planned work. The system maintains a reference within the work order that can tie the work back to the relevant contract.

D. Sub-contracts are not used to designate work as being Minnesota-specific. Rather the Company uses jurisdiction-specific work orders to track charges by state, as described in our response to Part C above.

E. The primary cause of our listing vendors without corresponding contracts in our DOC-49 dataset was the inadvertent omission of contracts from our response. These additional contracts are included as Attachment C to this response. Any relevant renewal documentation for the additional agreements is provided in Attachment B1 to this response.

[TRADE SECRET BEGINS

TRADE SECRET ENDS]

F. The Company utilizes different systems for the contract creation process in the Supply Chain area and the work management processing in the accounting/construction areas. Each of these systems utilizes different numbering conventions, but the work management systems have fields which provide references that link contracts from the Supply Chain system to the work management system.

Each new contract in Emptoris, our Supply Chain system, is assigned a unique, five-digit number. On the other hand, our legacy work management system, Passport, would also assign a unique, six-digit Passport number when work was tracked. Some contracts reference the Emptoris number while others reference the Passport number. Our new work management system, SAP, utilizes Outline Agreements (OA) to represent the contract (from Emptoris) in the work management system. SAP has its own unique numbering convention that is assigned to each OA. Despite the systems using different numbering systems, through references made in each system the Company is able to track work back to the contracts to ensure that charges are being assigned to the relevant contract.

To aid in tracking charges back to the contracts, we have developed Attachment D to this response. Attachment D, provided in live Excel spreadsheet format, is a subset of the information that was initially provided in the "Capital Data" and "O&M Data" tabs of DOC-49, Attachment A, but with the addition of contract numbers and vendor for each charge. The "Guide" tab of Attachment D provides instructions on how to map individual vendor-related charges to the contracts and explains the information provided in each tab of the Attachment. ***[TRADE SECRET BEGINS***

TRADE SECRET ENDS]

It should be noted that during the preparation of this response, it was discovered that two work orders related entirely to work completed in Colorado were incorrectly assigned accounting strings for Minnesota-related work in our new SAP work management system. The work orders relate to work performed by ***[TRADE SECRET BEGINS***

TRADE SECRET ENDS] The Company proposes to remove these charges in the final compliance version of this filing. The revenue requirement impact of these projects is approximately $213 in 2017 and $501 in 2018.

G. The "Capital Data" and "O&M" data tabs of Attachment D provide a listing of charges for outside vendor contract work. The Contract Number can be found in column A of each tab. For further information on how to track the individual charges to the relevant contracts, please refer to the "Guide" tab of Attachment D.

H. The intention of the data provided in DOC-49 was to provide the Department with individual charges including purchase order, vendor, and invoice number characteristics. With our response here, we hope to provide clarification as to the information provided and how it ties back to previously provided GUIC information.

Using DOC-49 data as the starting point for segregating into cost categories and type is not accurate, because the individual charge data at times mixes both capital and O&M expense types, and a portion of categories Materials, Transportation, Construction Overhead and Other relate to internal labor. Additional data is needed to breakdown the 2017 Capital Expenditures into cost categories and type, and Table 1 below summarizes the entirety of 2017 GUIC capital expenditures (i.e., recoverable and non-recoverable) by cost element group. The individual 2017 monthly charges totaling $25,643,640 can be found by cost element and internal order in Attachment E to this response.

Attachment E is provided in live Excel spreadsheet format. See the "2017 GUIC by Cost Element" and "2017 GUIC by Order" worksheet tabs. The Company is providing details underlying Table 1 below as Attachment E to this response. The Department can utilize this information to tie back to the figures included in Attachment E of the Company's Supplemental Filing.
[TRADE SECRET BEGINS

TRADE SECRET ENDS]

Table 1

2017 GUIC Capital Expenditures	Amount
Outside Vendor Contract	$17,366,758
Internal Labor (not eligible for recovery)	$489,849
Materials, Transportation, Construction Overhead, and Other Outside Services (not traceable to vendor master service agreements)	$7,787,033
Subtotal GUIC Expenditures	**$25,643,640**
RWIP	($3,684,742)
Sartell Betterment 28.1% Removal (not eligible for recovery)	($210,205)
Internal Labor (as of Supplemental Filing)	($1,374,082)
Supplemental Filing Total GUIC Expenditures, excluding internal labor	**$20,374,611**
Internal Labor (Reconciliation Difference)	$884,233
Reconciliation Total GUIC Expenditures	$21,258,844

The $17,366,758 for Contractor charges noted above is different than the ***[TRADE SECRET BEGINS TRADE SECRET ENDS]*** for Outside Vendor Contract charges that the Department summed from the data in DOC-49 partially due to mixed capital and O&M work orders in the respective capital and O&M datasets that could not be separated in that dataset. In addition, the cost element description, "Service Consumption" was used for additional outside vendor charges. The total of these charges, $3.7 million, has been included in the outside vendor contract total above and in the information provided in Attachment E, which includes data that captures all capital expenditures for Outside Vendor Contracts.[1] ***[TRADE SECRET BEGINS***

TRADE SECRET ENDS]

In the supplemental filing, we inadvertently removed too much internal labor from September 2017 to December 2017, due to both actual and forecasted amounts being included. As such, the GUIC capital expenditures were

[1] The $3.7 million amount initially labeled as service consumption in DOC-49, Attachment A, can be found on line 218 of the "A-2017 GUIC by Cost Element" tab of Attachment E to this response.

understated by approximately $900,000. We will not be requesting a modification to the requested revenue requirement to correct the error. In Table 1 and Attachment E to this response, the corrected capital expenditures and internal labor amounts will be incorporated in order to properly reconcile the differences in Total GUIC expenditures.

We believe that the additional information provided in this response and its attachments provides a clearer path for mapping vendor contracts/master service agreements to the corresponding charges for work completed. If after reviewing this response the Department would like further clarity on the relationships in the provided information, the Company would be happy to facilitate any desired discussions.

I. The categories included in the Capital Data tab provided in DOC-49, Attachment A cannot be easily separated into two categories of "Internal Labor" and "Materials, Transportation, Construction Overhead, and Other." The Company has provided Attachment E to this response, which is summarized in Table 1 above. The categories of Company Labor Loadings, Company OT Labor, and Company ST Labor are all considered internal labor. The remaining categories make up the "Materials, Transportation, Construction Overhead, and Other" bucket.

However, these amounts differ from the $489,849 of non-recoverable internal labor stated in Table 1, since a portion of the "Materials, Transportation, Construction Overhead, and Other" relate to internal labor. The Company identifies these amounts through a specialized query from our capital asset accounting database. Attachment E includes the detail of internal labor included in Table 1.

Portions of this inquiry and response, Attachments B1, B2, C and D are marked as "Not-Public" because they include confidential contract and pricing terms as well as vendor detail or confidential Company sourcing policy information considered to be trade secret data as defined by Minn. Stat. § 13.37(1)(b). This information has independent economic value, from not being generally known to, and not being readily ascertainable by other parties, who could obtain economic value from its disclosure or use. The disclosure of this information could adversely impact contract negotiations, potentially increasing costs for these services for our customers. Thus, Xcel Energy maintains this information as a trade secret pursuant to Minn. Rule 7829.0500.

Attachments B1, B2 and C are marked as "Not-Public" in their entirety. Pursuant to Minn. R. 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material:** Attachment B1 is a collection of change orders to contracts between the Company and its vendors for 2017 work on TIMP and DIMP projects. Attachment B2 is a confidential internal document detailing Company supply chain operating requirements. Attachment C is a collection of contracts between the Company and its vendors for 2017 work on TIMP and DIMP projects.
2. **Authors:** The contract renewal documentation included in Attachment B1, the supply chain requirements document, and the contract collection included in Attachment C were drafted by Xcel Energy Services legal and sourcing personnel.
3. **Importance:** We protect these contract terms, as disclosure can adversely affect negotiations and increase costs for services.
4. **Date the Information was Prepared:** Attachments B1 and C were prepared for this response May 2018. Attachment B2 was published in January 2016.

Preparer:	Austin Kerns / Ryan Cummings
Title:	Manager, Gas Strategy / Senior Analyst
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Date:	May 21, 2018

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Xcel Energy			
Docket No.:	G002/M-17-787		
Response To:	MN Department of Commerce	Information Request No.	63
Requestor:	Danielle Winner, Dorothy Morrissey		
Date Received:	June 7, 2018		

Question:

Topic:	Invoices, Cost Data
Reference(s):	IR 49 Response, Attachment A; IR 62 Response, Attachment E

Note that the Attachment to this IR is Trade Secret in its entirety.

A. Please provide copies of the invoices and work orders affiliated with each of the capital and O&M data entries listed in the trade secret Attachment A to this IR.

B. In IR 49 Response, Attachment A, in the tab labeled "2017 GUIC O&M Summary," the Company identified $3,444,087 of non-amortized O&M DIMP expenses. The Company also pointed out that the corresponding data produced a slightly higher figure of $3,502,807 due to mixed capital/O&M work orders being included in the O&M dataset.

In the data contributing to the $3.5 million figure, the Department observes the following cost elements: Contract Labor, Employee Expenses Meals, Employee Expenses Per Diem, License Fees and Permits, Materials, NonProd Bargaining Labor G1_OH Alloc, Non-Prod Labor Bargaining Benefit Grp 1, Other Compensation Craft Welfare Fund, Outside Vendor Contract, Overtime, Postage, Premium, Prod Labor Bargaining Benefit Group 1, Purchasing-Overhead, Purchasing_OH Allocation, Transportation Fleet Cost, Warehouse – Overhead, Warehouse Energy Supply_OH Allocation, and Warehouse_OH Allocation.

Of the above-listed cost elements, the Department understands how License Fees and Permits, Materials, and Outside Vendor Contract costs (approximately $3.25 million) would be incremental to costs already captured in base rates. However, it is unclear how the remaining cost elements (totaling approximately $249,000) are incremental to costs captured in base rates.

1. Please identify which O&M expenses have mixed O&M/capital w work orders.
2. Please demonstrate how the approximately $249,000 corresponding to the above-referenced cost elements (all but License Fees and Permits, Materials, and Outside Vendor Contract) are costs that are incremental to costs captured in base rates.

C. In response to IR 62, the Company provided the Department with a live workbook, Attachment E. Please explain how the figures in the tab labeled "D-2017 GUIC RWIP" were reached.

D. In IR 62 Response, Attachment E, tab A-2017 GUIC by Cost Element, approximately $6 million in capital expenditure projects have one or more of the following labels:

Asset Type: "Gas New Business"

Program Type: "Gas New Service"

Expenditure Type: "Non-Trans New Main," "Gas Trans New Main," and "New Main."

These descriptions used for such projects are distinguished from other projects labeled as "Renewal" or "Replacement" within same spreadsheet, which indicates that projects labeled "new" must not be a type of replacement. The GUIC statute specifies that gas utility projects are "replacement" and "modification" of old equipment, and may not connect new customers or add new revenue. For each of the projects with the "new" labels, please demonstrate (1) how they are eligible as a GUIC project under the statute, or (2) that they are not included in the Company's GUIC-eligible projects.

E. In the Company's response to IR 62, in Attachment E, the Company states that approximately $7,787,033 of total GUIC expenditures (before ineligible expenditures are backed out) are attributable to Materials, Transportation, Construction Overhead, and Other Outside Services, and that these services are not traceable to vendor master service agreements. The Company also stated that a portion of these costs "relate to internal labor."

1. Please identify which expenditures that have a Resource Group of Materials, Transportation, Overhead, or Other are for internal labor.

2. Please identify which expenditures that have a Resource Group of Materials, Transportation, Overhead, or Other have been backed out of the Company's calculation of GUIC-eligible capital expenditures.
3. For any expenditures with a Resource Group of Overhead that are not considered internal labor, please explain why non-internal overhead costs do not trace back to a master contract.
4. The Department observes approximately $5,000 costs with a Resource Group of Other have Cost Elements related to various Employee Expenses. Please demonstrate that these employee expenses are above and beyond the representative allowance included in the Company's last rate case.

Response:

A. Please note: We will supplement this response with the Company's Attachment A, which will provide information regarding invoices and work orders affiliated with each of the capital and O&M data entries listed in the Department of Commerce's Attachment A to this inquiry, and we will also then provide Attachment B, which will include copies of the listed invoices.

B-1. To clarify, the difference between the figures of $3,444,087 and $3,502,807 of non-amortized O&M DIMP expenses listed in the Company's response to DOC IR 49, Attachment A is due to non-GUIC recoverable internal labor related to the Sewer Conflict Investigation Program (WBS A.0008410.163.001.004 and A.0008510.114.001.002), as shown in Attachment C to the present response. Attachment C is provided in live Excel spreadsheet format.

The O&M expenses resulting from mixed capital/O&M work orders totaled $15,978.61. Cost and accounting details of these amounts are provided in Attachment C to this response. These expenses were not included in the DIMP O&M expenses of $3,444,087 and $3,502,807 in the response to DOC IR 49, Attachment A, and they are not part of the Company's GUIC request.

B-2. Our current base rates were approved in our previous general gas rate case, Docket No. G002/GR-09-1153. The approved revenue requirements were based on a 2010 test year that did not include any O&M costs for DIMP activities. The 2010 test year included O&M cost elements shown in our response to DOC IR 49; however these O&M costs levels were intended for non-DIMP related work. Since there is no DIMP work intended in the cost estimates used to develop our current base rates; all of the DIMP costs shown in our response to DOC IR 49 are incremental to the base rate cost levels.

C. The Company identifies these amounts through our capital asset accounting system. As an asset is being constructed, costs are charged against a specific work order, and for each work order there is a unit estimate set up by the project engineer. A percentage split between CWIP and RWIP for the project is assigned to each unit estimate. The Company uses this unit estimate to split actual expenditures between CWIP and RWIP. The revenue requirement calculation picks up both the CWIP and RWIP items for rider eligible projects for inclusion in the GUIC rider.

D. An Asset Type of "Gas New Business", Program Type of "Gas New Service", or Expenditure Type of "Non-Trans New Main", "Gas Trans New Main", and "New Main" does not specifically mean that those assets are used for serving new customers. They refer to the installation of new assets that are not retiring assets of the same type. For instance, a distribution main replacing an existing distribution main would be classified as a "Main Renewal" since there is an asset of like-type being installed and retired. In the case of some GUIC projects, existing Transmission or Non-Transmission Assets are being replaced with distribution assets. In this case, a "New Main" of the distribution asset class is installed and no distribution assets are being retired. In other cases such as the installation of 4-inch and 6-inch emergency valves, the valve asset on the main did not exist, so a "New Main" asset is installed. If no valve was existing, there is no asset to specifically "Renew."

The $6 million figure referenced in the question is comprised of five projects that relate to the replacement of transmission assets with distribution assets and three projects that relate to the installation of new distribution valves: These projects are listed in the table below. GUIC recovery of projects for the replacement of transmission assets with distribution assets is permissible per Minn. Stat. § 216B.1635, subd. 1(c)(2), and recovery of new distribution valve projects is allowable per Minn. Stat. § 216B.1635, subd. 1(b)(3).

WBS 2	Parent	Parent Descr	Sub-Projects
Transmission Asset Replacements with Distribution			
E.0000004.019	11649797	TL0206 High Bridge Lateral Replacement	High Bridge Lateral Replacement
E.0000009.018	34000342	TL0206 High Bridge Lateral Replacement	High Bridge Lateral Replacement
E.0000004.048	34003261	NSPM Trans and IP Pipe	Montreal/Island Line Replacement
E.0000004.064	11810375	Repl 12in Upper 55 to S. St. Paul Reg Stat	Crossover Line
E.0000030.004	12013233	East Metro Pipeline Repl Regr Station Install	East Metro Replacement Project
Installation of New Distribution Valves			
E.0010011.005	50000646	NSPM Install 6" and 4" Distribution Valves	Distribution Valve Installation
E.0000004.075	11649520	NSPM Install 6" and 4" Distribution Valves	Distribution Valve Installation
E.0000004.054	11649520	NSPM Install 6" and 4" Distribution Valves	Distribution Valve Installation

E-1. Within the "Materials, Transportation, Overhead, or Other" resource groups, overhead includes a small amount of costs for internal labor identified by the cost element (approximately $100 in the Company's response to DOC IR 62, Attachment E). However, while included in this resource group, the revenue requirement model specifically identifies internal labor by cost element and excludes all internal labor from the revenue requirement calculation. Please see Attachment D to the present response. Attachment D is provided in live Excel spreadsheet format.

E-2. Within the "Materials, Transportation, Overhead, or Other" resource groups, costs related to the Sartell Betterment 28.1 percent not eligible for recovery has been backed out (approximately $49,000 are backed out and included in the overall Sartell Betterment Removal). Please see Attachment D.

E-3. Overhead cost (or indirect costs) allocation is a method of allocating costs that are incurred in normal business but cannot be directly assigned to a particular function or activity without excessive cost for the benefit received. These expenses are assigned to all functions using an allocation method. Each capital work order install or removal is assigned an overhead code. This code determines the type of overhead costs the project receives. This policy reflects consistent accounting that complies with FERC guidelines and SEC regulations for the addition of overhead costs to capital assets across all Xcel Energy utility subsidiary companies. A majority of these charges are associated with internal costs only.

E-4. No costs are being recovered in our current base rates for DIMP work. As such the approximately $3,300 DIMP-related employee expenses for the Other resource group are incremental to base rate cost levels. Please see our response to Part B-2. above.

There was approximately $480,000 in annual O&M expenditures for TIMP related work included in our base rates approved in the last general gas rate case. These costs have been removed from our GUIC request. As such all TIMP costs included in our request are incremental to costs levels recovered in our base rates. As such any of the approximately $1,300 in employee expenses for the Other resource group are incremental to our base rate cost levels.

Attachments A and B to this response are marked as "Not-Public" because they include confidential contract and pricing terms as well as vendor detail considered to be trade secret data as defined by Minn. Stat. § 13.37(1)(b). This information has independent economic value, from not being generally known to, and not being readily ascertainable by other parties, who could obtain economic value from its disclosure or use. The disclosure of this information could adversely impact contract negotiations, potentially increasing costs for these services for our customers. Thus, Xcel Energy maintains this information as a trade secret pursuant to Minn. Rule 7829.0500.

Attachments A and B are marked as "Not-Public" in their entirety. Pursuant to Minn. R. 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material:** Attachment A is a list of vendor invoice and Company payment information for work on a selected group of capital and O&M TIMP and DIMP projects. Attachment B is a collection of copies of invoices listed in Attachment A.
2. **Authors:** The invoice information was prepared by Xcel Energy sourcing and distribution finance personnel.
3. **Importance:** We protect this invoicing information, as disclosure can adversely affect negotiations and increase costs for services.
4. **Date the Information was Prepared:** Attachments A and B were prepared for this response in June 2018.

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Date:	June 18, 2018

Table 1. Contract Jurisdiction (PUBLIC)

Vendor	Contract	Effective Date	Emptoris/Other Number	Contract or Master Agreement Number (Passport)	Work Order Numbers	Xcel Affiliates in Contract	Geographic Scope of Work	Pricing Schedules Included
						NSP-MN	MN, ND	
					293978 (NSP-MN) 293979 (NSP-WI) 293980 (PSCo)	NSP-MN, NSP-WI, PSCo	MN, ND, WI, CO	NSP, PSCo
					331053 (NSP-MN) 331054 (NSP-WI) 331055 (PSCo)	NSP-MN, NSP-WI, PSCo	MN, WI, CO	NSP, PSCo
						NSP-MN, NSP-WI		
					271512 (NSP-MN) 272164 (NSP-WI)	NSP-MN, NSP-WI	MN, ND, SD, WI	NSP-MN, NSP-WI
						NSP-MN, NSP-WI	MN, ND, WI	NSP-MN, NSP-WI
						NSP-MN, NSP-WI	MN, ND, WI	NSP-MN, NSP-WI
						NSP-MN, NSP-WI	MN, ND, WI	NSP-MN, NSP-WI
						NSP-MN, NSP-WI, PSCo, SW PSC-NM		NSP, PSCo
					369277	NSP-MN, NSP-WI, PSCo, SW PSC-NM		
						NSP-MN, NSP-WI, PSCo, SW PSC-NM		NSP, PSCo
					370422 28106	NSP-MN, NSP-WI, PSCo, SW PSC-NM		
						NSP-MN, NSP-WI, PSCo, SW PSC-NM		
						NSP-MN		
						NSP-MN, NSP-WI, PSCo, SW PSC-NM		
						NSP-MN, NSP-WI, PSCo, SW PSC-NM		
						NSP-MN		
						NSP-MN, NSP-WI, PSCo, SW PSC-NM		
						NSP-MN, NSP-WI		
						NSP-MN and Xcel Energy Services Inc (DE)		
						NSP-MN, NSP-WI, PSCo, SW PSC-NM		
						NSP-MN, NSP-WI, PSCo, SW PSC-NM		
						NSP-MN, NSP-WI, PSCo, SW PSC-NM		
						PSCo		
						NSP-MN, NSP-WI		
						NSP-MN		
						NSP-MN, NSP-WI, PSCo, SW PSC-NM, Xcel (DE)		
						NSP-MN		
						NSP-MN		
						NSP-MN, NSP-WI, PSCo, SW PSC-NM, Xcel (DE)		
						NSP-MN, NSP-WI, PSCo, SW PSC-NM		
						NSP-MN, NSP-WI, PSCo		
						NSP-MN, NSP-WI		
						NSP-MN		
						NSP-MN, NSP-WI, PSCo, SW PSC-NM, Xcel (DE)		
	Work not in MN- proposed for removal							
	non-contract vendor							
	non-contract vendor							
	non-contract vendor							
	Work not in MN- proposed for removal							

Table 2. Data Jurisdiction (PUBLIC)

Vendor	Emptoris/Other Number	Contract or Master Agreement Number (Passport)	Work Order Numbers	Data Discrepancies	Amount in "Capital Data"	Amount in O&M Data	MN Work?
					21,686	2,960,275	Cap work appears to be MN, O&M Work unclear
			293978 (NSP-MN) 293979 (NSP-WI) 293980 (PSCo)		3,784,928	79,160	Appears to be all MN
			331053 (NSP-MN) 331054 (NSP-WI) 331055 (PSCo)		359,833	23,294	Appears to be all MN
					35,676	9,442	Appears to be all MN
			271512 (NSP-MN) 272164 (NSP-WI)		8,295,196	1,206,494	Appears to be all MN
				Two different contracts provided for vendor, neither of which have a passport number that match the data (393141)	3,719,656		Appears to be all MN
						1,531	Appears to be all MN
					24,365		Appears to be all MN
				Data has different passport number from contract (355435)	77,933		Appears to be all MN
			369277		219,359		Appears to be all MN
				Two different contracts provided for vendor, neither of which have a passport number that match the data (393141)	-		n/a
			370422 28106		1,049,726		Appears to be all MN
					256,079		Appears to be all MN
					308,563		Appears to be all MN
				Two different contracts provided for vendor, neither of which have a passport number that match the data (393399)	116,199		Appears to be all MN
					1,368		Appears to be all MN
					5,077		Appears to be all MN
					96,720		Appears to be all MN
				passport number not in contract, only data	30,148		Appears to be all MN
					552		Appears to be all MN
					48,572		Appears to be all MN
					11,760		Appears to be all MN
					14,450		Appears to be all MN
							n/a
					4,958		Appears to be all MN
				different company names for same contract numbers		1,499	Appears to be all MN
					513,752		Appears to be all MN
						2,945	Appears to be all MN

					1,396	5,799	Cap work appears to be MN, O&M Work unclear
				no passport number in contract		6,550	unlcear
					106		Appears to be all MN
					2,475		Appears to be all MN
					7,735		Appears to be all MN
					22,216		Appears to be all MN
					5,936		Appears to be all MN
					4,012		Work not in MN-proposed for removal
	non-contract vendor				10,230	10,230	Appears to be all MN
	non-contract vendor				6,754		Appears to be all MN
	non-contract vendor				175		Appears to be all MN
					450		Work not in MN-proposed for removal

Table 3. Jurisdictionally Unclear Data (PUBLIC)

Contract No.	Vendor	Filing Order with Name	Posting Date	Cost element descr.	Name	Vbl. value/Obj. curr	Order	CO object name	WBS Name	WBS LV 2 name
		12440381-SEWER REPAIR - GUIC RELATED	1/5/2017	Outside Vendor Contract		677.50	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	1/5/2017	Outside Vendor Contract		620.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	1/17/2017	Outside Vendor Contract		677.50	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	1/17/2017	Outside Vendor Contract		677.50	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	1/17/2017	Outside Vendor Contract		562.50	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12285039-16 SEWER MITIGATION - DIMP / GUIC	1/22/2017	Outside Vendor Contract		8,255.33	200002198915	CONTRACTOR COSTS - SERVICES	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	1/22/2017	Outside Vendor Contract		1,370.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	1/22/2017	Outside Vendor Contract		895.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	1/26/2017	Outside Vendor Contract		1,630.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	1/26/2017	Outside Vendor Contract		1,105.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	1/26/2017	Outside Vendor Contract		1,000.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	1/26/2017	Outside Vendor Contract		1,210.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	1/26/2017	Outside Vendor Contract		6,841.19	200002575565	CONTRACTOR COSTS - SERVICES	MNGUIC -	MN GUIC
		12440381-SEWER REPAIR - GUIC RELATED	2/5/2017	Outside Vendor Contract		1,105.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	2/5/2017	Outside Vendor Contract		790.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	2/5/2017	Outside Vendor Contract		685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	2/5/2017	Outside Vendor Contract		895.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	2/5/2017	Outside Vendor Contract		562.50	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	2/5/2017	Outside Vendor Contract		505.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	2/5/2017	Outside Vendor Contract		7,054.86	200002575565	CONTRACTOR COSTS - SERVICES	MNGUIC -	MN GUIC
		12440381-SEWER REPAIR - GUIC RELATED	2/19/2017	Outside Vendor Contract		1,105.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	2/19/2017	Outside Vendor Contract		1,000.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	2/19/2017	Outside Vendor Contract		1,210.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	2/19/2017	Outside Vendor Contract		895.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	2/19/2017	Outside Vendor Contract		1,210.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	2/19/2017	Outside Vendor Contract		895.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	2/19/2017	Outside Vendor Contract		790.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	2/19/2017	Outside Vendor Contract		7,401.71	200002575565	CONTRACTOR COSTS - SERVICES	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	2/19/2017	Outside Vendor Contract		5,850.11	200002575565	CONTRACTOR COSTS - SERVICES	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	3/1/2017	Outside Vendor Contract		6,076.62	200002575565	CONTRACTOR COSTS - SERVICES	MNGUIC -	MN GUIC
		12440381-SEWER REPAIR - GUIC RELATED	3/1/2017	Outside Vendor Contract		1,945.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	3/1/2017	Outside Vendor Contract		1,945.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	3/1/2017	Outside Vendor Contract		790.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	3/1/2017	Outside Vendor Contract		1,420.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	3/2/2017	Outside Vendor Contract		1,370.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	3/2/2017	Outside Vendor Contract		1,315.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	3/21/2017	Outside Vendor Contract		685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	3/12/2017	Outside Vendor Contract		1,105.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	3/12/2017	Outside Vendor Contract		1,000.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	3/12/2017	Outside Vendor Contract		1,105.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	3/12/2017	Outside Vendor Contract		6,778.12	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12440381-SEWER REPAIR - GUIC RELATED	3/28/2017	Outside Vendor Contract		790.00	200002485112	CONTRACTOR REPAIRS TO MAIN SEWER LATERA	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	3/28/2017	Outside Vendor Contract		790.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	3/28/2017	Outside Vendor Contract		685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	3/28/2017	Outside Vendor Contract		685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	3/28/2017	Outside Vendor Contract		580.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	3/28/2017	Outside Vendor Contract		790.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	3/28/2017	Outside Vendor Contract		15,905.40	200002575565	CONTRACTOR COSTS - SERVICES	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	3/28/2017	Outside Vendor Contract		6,937.28	200002575565	CONTRACTOR COSTS - SERVICES	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	3/31/2017	Outside Vendor Contract		10,760.98	200002575565	CONTRACTOR COSTS - SERVICES	MNGUIC -	MN GUIC
		12440381-SEWER REPAIR - GUIC RELATED	3/31/2017	Outside Vendor Contract		790.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	5/10/2017	Outside Vendor Contract		685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	3/31/2017	Outside Vendor Contract		1,000.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	3/31/2017	Outside Vendor Contract		895.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	4/11/2017	Outside Vendor Contract		895.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	4/11/2017	Outside Vendor Contract		1,050.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	4/11/2017	Outside Vendor Contract		1,000.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	4/11/2017	Outside Vendor Contract		1,000.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	4/11/2017	Outside Vendor Contract		25,357.54	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	4/13/2017	Outside Vendor Contract		47,821.96	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12440381-SEWER REPAIR - GUIC RELATED	4/17/2017	Outside Vendor Contract		790.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	4/13/2017	Outside Vendor Contract		895.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	4/13/2017	Outside Vendor Contract		1,210.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	4/13/2017	Outside Vendor Contract		790.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	4/13/2017	Outside Vendor Contract		895.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	4/13/2017	Outside Vendor Contract		790.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	4/17/2017	Outside Vendor Contract		685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	4/17/2017	Outside Vendor Contract		685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	4/17/2017	Outside Vendor Contract		895.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	4/25/2017	Outside Vendor Contract		685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	4/25/2017	Outside Vendor Contract		895.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	4/25/2017	Outside Vendor Contract		1,000.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	4/25/2017	Outside Vendor Contract		24,851.80	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	5/1/2017	Outside Vendor Contract		34,195.28	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12440381-SEWER REPAIR - GUIC RELATED	5/1/2017	Outside Vendor Contract		790.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	5/1/2017	Outside Vendor Contract		790.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	5/1/2017	Outside Vendor Contract		677.50	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	5/4/2017	Outside Vendor Contract		790.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	5/4/2017	Outside Vendor Contract		685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	5/14/2017	Outside Vendor Contract		284.84	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	5/14/2017	Outside Vendor Contract		142.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	5/23/2017	Outside Vendor Contract		685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	5/23/2017	Outside Vendor Contract		790.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	5/29/2017	Outside Vendor Contract		1,000.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	6/4/2017	Outside Vendor Contract		35,043.37	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	6/4/2017	Outside Vendor Contract		57,961.71	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	6/4/2017	Outside Vendor Contract		29,655.09	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	6/4/2017	Outside Vendor Contract		88,053.26	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	6/4/2017	Outside Vendor Contract		63,149.69	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12440381-SEWER REPAIR - GUIC RELATED	6/4/2017	Outside Vendor Contract		1,420.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	6/4/2017	Outside Vendor Contract		1,000.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	6/4/2017	Outside Vendor Contract		895.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	6/4/2017	Outside Vendor Contract		580.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	6/4/2017	Outside Vendor Contract		685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	6/4/2017	Outside Vendor Contract		580.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	7/21/2017	Outside Vendor Contract		69,684.69	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	6/26/2017	Outside Vendor Contract		92,219.95	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	6/26/2017	Outside Vendor Contract		86,794.47	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	6/26/2017	Outside Vendor Contract		176.24	200002575565	CONTRACTOR COSTS - SERVICES	MNGUIC -	MN GUIC
		12440381-SEWER REPAIR - GUIC RELATED	6/26/2017	Outside Vendor Contract		1,000.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	6/26/2017	Outside Vendor Contract		790.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	6/26/2017	Outside Vendor Contract		790.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	6/26/2017	Outside Vendor Contract		580.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	6/26/2017	Outside Vendor Contract		580.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	6/26/2017	Outside Vendor Contract		790.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	6/26/2017	Outside Vendor Contract		1,000.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	6/26/2017	Outside Vendor Contract		685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	6/26/2017	Outside Vendor Contract		790.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	7/21/2017	Outside Vendor Contract		86,317.20	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12440381-SEWER REPAIR - GUIC RELATED	7/21/2017	Outside Vendor Contract		895.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	7/21/2017	Outside Vendor Contract		895.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	7/21/2017	Outside Vendor Contract		580.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	7/21/2017	Outside Vendor Contract		176.24	200002575565	CONTRACTOR COSTS - SERVICES	MNGUIC -	MN GUIC
		12440381-SEWER REPAIR - GUIC RELATED	7/21/2017	Outside Vendor Contract		685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	7/21/2017	Outside Vendor Contract		95,702.77	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	7/21/2017	Outside Vendor Contract		88,124.92	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	7/21/2017	Outside Vendor Contract		66,218.68	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12440381-SEWER REPAIR - GUIC RELATED	7/21/2017	Outside Vendor Contract		895.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	7/21/2017	Outside Vendor Contract		685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	7/21/2017	Outside Vendor Contract		580.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	7/21/2017	Outside Vendor Contract		895.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	7/31/2017	Outside Vendor Contract		102,765.21	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12440381-SEWER REPAIR - GUIC RELATED	7/31/2017	Outside Vendor Contract		685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	7/31/2017	Outside Vendor Contract		580.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	8/15/2017	Outside Vendor Contract		90,876.67	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	8/15/2017	Outside Vendor Contract		108,099.31	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12440381-SEWER REPAIR - GUIC RELATED	8/15/2017	Outside Vendor Contract		580.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	8/15/2017	Outside Vendor Contract		580.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	8/28/2017	Outside Vendor Contract		87,973.75	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	8/31/2017	Outside Vendor Contract		84,876.03	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12440381-SEWER REPAIR - GUIC RELATED	8/30/2017	Outside Vendor Contract		685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	9/6/2017	Outside Vendor Contract		105,445.35	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12440381-SEWER REPAIR - GUIC RELATED	9/8/2017	Outside Vendor Contract		685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009

		12440381-SEWER REPAIR - GUIC RELATED	9/8/2017	Outside Vendor Contract	620.00	200002485112	CONTRACTOR REPAIRS TO MAIN SEWER LATERA	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	9/8/2017	Outside Vendor Contract	790.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	9/8/2017	Outside Vendor Contract	89,859.42	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	9/15/2017	Outside Vendor Contract	82,444.87	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	9/27/2017	Outside Vendor Contract	90,659.76	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12440381-SEWER REPAIR - GUIC RELATED	9/25/2017	Outside Vendor Contract	620.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	9/25/2017	Outside Vendor Contract	685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	9/25/2017	Outside Vendor Contract	790.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	10/2/2017	Outside Vendor Contract	97,523.83	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12440381-SEWER REPAIR - GUIC RELATED	10/2/2017	Outside Vendor Contract	685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	10/4/2017	Outside Vendor Contract	685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	10/7/2017	Outside Vendor Contract	125,654.90	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12440381-SEWER REPAIR - GUIC RELATED	10/16/2017	Outside Vendor Contract	685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	10/16/2017	Outside Vendor Contract	685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	10/16/2017	Outside Vendor Contract	790.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	10/20/2017	Outside Vendor Contract	96,012.28	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	10/23/2017	Outside Vendor Contract	103,759.63	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12440381-SEWER REPAIR - GUIC RELATED	10/23/2017	Outside Vendor Contract	685.00	200002485112	CONTRACTOR REPAIRS TO MAIN SEWER LATERA	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	10/23/2017	Outside Vendor Contract	580.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	10/23/2017	Outside Vendor Contract	685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	10/23/2017	Outside Vendor Contract	685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	10/23/2017	Outside Vendor Contract	685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	10/23/2017	Outside Vendor Contract	790.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	10/30/2017	Outside Vendor Contract	114,448.05	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	11/13/2017	Outside Vendor Contract	101,803.98	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	11/13/2017	Outside Vendor Contract	123,240.59	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12440381-SEWER REPAIR - GUIC RELATED	11/13/2017	Outside Vendor Contract	685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	11/13/2017	Outside Vendor Contract	580.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	11/13/2017	Outside Vendor Contract	580.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	11/13/2017	Outside Vendor Contract	685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	11/13/2017	Outside Vendor Contract	685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	11/13/2017	Outside Vendor Contract	580.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	11/13/2017	Outside Vendor Contract	685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	11/21/2017	Outside Vendor Contract	99,054.40	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	11/21/2017	Outside Vendor Contract	79,738.75	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12440381-SEWER REPAIR - GUIC RELATED	11/21/2017	Outside Vendor Contract	685.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	11/21/2017	Outside Vendor Contract	580.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	11/21/2017	Outside Vendor Contract	475.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	11/10/2017	Outside Vendor Contract	3,275.00	200002575491	ENGINEERING - OTHER COSTS	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	12/12/2017	Outside Vendor Contract	3,275.00	200002575491	ENGINEERING - OTHER COSTS	MNGUIC -	MN GUIC
		12440381-SEWER REPAIR - GUIC RELATED	1/17/2017	Outside Vendor Contract	518.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	1/31/2017	Outside Vendor Contract	349.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	2/20/2017	Outside Vendor Contract	518.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	2/21/2017	Outside Vendor Contract	349.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	3/1/2017	Outside Vendor Contract	518.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	3/1/2017	Outside Vendor Contract	518.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	5/1/2017	Outside Vendor Contract	349.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	5/31/2017	Outside Vendor Contract	518.00	200002485112	CONTRACTOR REPAIRS TO MAIN SEWER LATERA	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	7/10/2017	Outside Vendor Contract	777.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	10/2/2017	Outside Vendor Contract	518.00	200002485112	CONTRACTOR REPAIRS TO MAIN SEWER LATERA	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	10/13/2017	Outside Vendor Contract	349.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	11/6/2017	Outside Vendor Contract	518.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	1/29/2017	Outside Vendor Contract	1,499.46	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	9/15/2017	Outside Vendor Contract	349.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12440381-SEWER REPAIR - GUIC RELATED	11/6/2017	Outside Vendor Contract	-349.00	200002485165	INSPECT/CAMERA FROM HOUSE TO STREET	MNGUIC -	MNGUIC - 1009
		12411154-TL0209 / E COUNTY LINE CASING PRES	4/28/2017	Outside Vendor Contract	20,000.00	200002436291	OUTSIDE SERVICES	MNGUIC -	MNGUIC - 1009
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	12/2/2017	Outside Vendor Contract	250.20	200002575491	ENGINEERING - OTHER COSTS	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	8/31/2017	Outside Vendor Contract	136.35	200002575514	CONTRACTOR COSTS - MAINS	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	3/7/2017	Outside Vendor Contract	75.85	200002575491	ENGINEERING - OTHER COSTS	MNGUIC -	MN GUIC
		12487770-17 SEWER MITIGATION - DIMP/GUIC -	3/7/2017	Outside Vendor Contract	40.25	200002575491	ENGINEERING - OTHER COSTS	MNGUIC -	MN GUIC
		200002062451-Mapping-880771-880771	8/31/2017	Outside Vendor Contract	-361.96	200002062451	Mapping-880771-880771	Table 11-101	Table 11-1012-0010

Table 4. Audit of Capital Invoice/Work Order Jurisdiction (PUBLIC)

Contract No.	Vendor	Purchasing Doc/Contract Auth.	Filing Order with Name	Posting Date	Cost element descr.	Vbl. value/Obj. curr	MN Jurisdiction on Invoice Copy
			100362538-Montreal Line S Renewal - Construction	12/7/2017	Service Consumption	1,954,069.82	confirmed
			100404773-Island Line S Renewal - Construction	12/13/2017	Service Consumption	799,717.61	confirmed
			100404773-Island Line S Renewal - Construction	12/15/2017	Service Consumption	772,760.38	confirmed
			12403875-SARTELL RIVER CROSSING / GAS MAIN RE-INFORCEMENT	2/1/2017	Outside Vendor Contract	609,695.58	confirmed
			11818868-EAST METRO PIPELINE REPLACEMENT PROJECT (2016 INSTALLATION)	4/30/2017	Outside Vendor Contract	233,650.25	confirmed
			12403875-SARTELL RIVER CROSSING / GAS MAIN RE-INFORCEMENT	3/28/2017	Outside Vendor Contract	210,256.00	confirmed
			12505914-WINONA-3RD ST. BTN. WINONA ST. & LIBERTY ST.-2017 DIMP	8/16/2017	Outside Vendor Contract	139,215.19	confirmed
			11818868-EAST METRO PIPELINE REPLACEMENT PROJECT (2016 INSTALLATION)	6/20/2017	Outside Vendor Contract	120,086.75	confirmed
			12359008-IMP - TL0206 ISLAND LINE SOUTH MAKE PIGGABLE	1/9/2017	Outside Vendor Contract	112,192.87	confirmed
			11818868-EAST METRO PIPELINE REPLACEMENT PROJECT (2016 INSTALLATION)	7/25/2017	Outside Vendor Contract	108,219.92	confirmed
			100404773-Island Line S Renewal - Construction	12/17/2017	Service Consumption	103,783.23	confirmed
			12526379-INSTALL NEW MONTREAL LINE SOUTH	11/7/2017	Outside Vendor Contract	56,505.49	confirmed
			100382714-01432348 NO ST PAUL 18TH AVE INSTALL 560	10/20/2017	Outside Vendor Contract	19,597.48	confirmed
			12531351-COLBY LAKE LATERAL RENEWAL (WOODLANE TO COLBY LK)	11/29/2017	Outside Vendor Contract	17,333.01	confirmed
			12356426-JSW:LKC:DIMP:LAKEWOOD AVE: RENEW PEA MAIN	10/23/2017	Outside Vendor Contract	16,763.43	confirmed
			12359008-IMP - TL0206 ISLAND LINE SOUTH MAKE PIGGABLE	7/21/2017	Outside Vendor Contract	15,262.67	confirmed
			12366775-IMP - TL0200 ROSEMOUNT LINE INVER HILLS LATERAL ILI	11/20/2017	Outside Vendor Contract	13,052.50	confirmed
			12356426-JSW:LKC:DIMP:LAKEWOOD AVE: RENEW PEA MAIN	12/15/2017	Outside Vendor Contract	10,164.20	confirmed
			12523417-CROSSOVER LINE RELOCATION PROJECT (UPPER 55 TO SSTP ST)	10/19/2017	Outside Vendor Contract	9,385.05	confirmed
			12364289-RCV ACTUATOR INSTALLATION - LAKE ELMO 1B TBS	1/31/2017	Outside Vendor Contract	3,746.02	confirmed
			12320752-ST. PAUL-ETNA-BIRMINGHAM-WINCHELL BTN HOYT & ARLINGTON-2016	11/30/2017	Outside Vendor Contract	-7,686.58	confirmed
			12526379-INSTALL NEW MONTREAL LINE SOUTH	10/7/2017	Outside Vendor Contract	-11,784.94	not applicable
			12364484-IMP - TL0209 E COUNTY LINE CASING REMOVAL	4/28/2017	Outside Vendor Contract	-20,000.00	not applicable
			12344852-ROSEVILLE/ CO RD C PROJECT/ INSTALL 19850' OF 2" & 3550' 4"	4/27/2017	Service Consumption	-21,400.00	confirmed
			12317856-SHOREVIEW/ NANCY PL/ INSTALL 7600' OF 2" PE MAIN	1/30/2017	Outside Vendor Contract	-29,397.60	confirmed

Table 5. Audit of O&M Invoice/Work Order Jurisdiction (PUBLIC)

Posting Date	Cost element descr.	Name	Vbl. value/Obj. curr	CO object name	MN Jurisdiction on Invoice Copy?
2/1/2017	Outside Vendor Contract	03512024~UMN0760803 WALKER 01/06/17 1/26/17	609,695.58	SARTELL RIVER CROSSING / GAS MAIN RE-INF	confirmed
2/28/2017	Engineering and Super - Overhead	MN-E&S-Gas Dist	320,588.47	SARTELL RIVER CROSSING / GAS MAIN RE-INF	not applicable
7/1/2017	Outside Vendor Contract	FERC 874 - Sewer Conflict Amor	292,886.62	Sewer Conflict Amort-Dist Op Mains&Svcs	not applicable
5/1/2017	Outside Vendor Contract	FERC 874 - Sewer Conflict Amor	292,886.62	Sewer Conflict Amort-Dist Op Mains&Svcs	not applicable
5/31/2017	Outside Vendor Contract	NNNL01 accrual 5/2017	143,746.67	CONTRACTOR COSTS - MAINS	confirmed
5/31/2017	Outside Vendor Contract	NNNL01 accrual 5/2017	130,116.44	CONTRACTOR COSTS - SERVICES	confirmed
6/30/2017	Contract Outside Vendors-Settle_Indir		83,815.20	CONTRACTOR COSTS - SERVICES	confirmed
12/31/2017	Outside Vendor Contract	t3088 Dec Q3 - 2 Accruals	45,000.00	SLEEVE RISER / ST CLOUD RISER SLEEVES 20	confirmed
5/31/2017	Outside Vendor Contract	tc258 CPA accrual May 2017 co10	44,075.20	SLEEVE RISER / ST CLOUD RISER SLEEVES 20	confirmed
8/31/2017	Purchasing_OH Allocation	200031 Purch Overhead Load-Alloc	10,361.20	CONTRACTOR COSTS - MAINS	not applicable
3/13/2017	Materials	MANAGED SERVICES 03/01/1	3,275.00	ENGINEERING - OTHER COSTS	unclear
11/10/2017	Outside Vendor Contract	DATA BASE MANAGEMENT 2010-2012 I	3,275.00	ENGINEERING - OTHER COSTS	unclear
6/1/2017	Outside Vendor Contract	NNNL01accrual 5/2017	-143,746.67	CONTRACTOR COSTS - MAINS	not applicable
9/30/2017	Contract Outside Vendors-Settle_Indir		-368,409.40	CONTRACTOR COSTS - MAINS	confirmed

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
Corrected Public Comments

Docket No. G002/M-17-787

Dated this 3rd day of July 2018

/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_17-787_M-17-787
Alison C	Archer	aarcher@misoenergy.org	MISO	2985 Ames Crossing Rd Eagan, MN 55121	Electronic Service	No	OFF_SL_17-787_M-17-787
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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_17-787_M-17-787
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Ian	Dobson	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	Yes	OFF_SL_17-787_M-17-787
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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_17-787_M-17-787