Xcel Energy®

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March 13, 2017

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—Via Electronic Filing—

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

RE: REPLY COMMENTS
2017 GAS UTILITY INFRASTRUCTURE COST RIDER
DOCKET NO. G002/M-16-891

Dear Mr. Wolf:

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission the enclosed Reply Comments in response to the March 1, 2017 Comments of the Minnesota Department of Commerce and the Office of the Attorney General-Antitrust and Utilities Division in the above-referenced docket.

Section A.2. of our Reply and Attachment B as provided with the Not-Public version of this filing include information considered to be trade secret data as defined by Minn. Stat. § 13.37(1)(b). This data includes confidential contract terms and vendor invoicing information. 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.

We have electronically filed this document with the Commission, and copies have been served on the parties on the attached service list. If you have any questions regarding this filing, please contact me at amy.a.liberkowski@xcelenergy.com or (612) 330-6613.

SINCERELY,

/s/

AMY A. LIBERKOWSKI
DIRECTOR, REGULATORY PRICING AND ANALYSIS

Enclosures
c: Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Nancy Lange	Chair
Dan Lipschultz	Commissioner
Matthew Schuerger	Commissioner
Katie J. Sieben	Commissioner
John A. Tuma	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY FOR APPROVAL OF A GAS UTILITY INFRASTRUCTURE COST RIDER TRUE-UP REPORT FOR 2016, REVENUE REQUIREMENTS FOR 2017, AND REVISED ADJUSTMENT FACTORS

DOCKET NO. G002/M-16-891

REPLY COMMENTS

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission these Reply Comments in response to the March 1, 2017 Comments of the Minnesota Department of Commerce (Department) and the Office of the Attorney General-Antitrust and Utilities Division (OAG) in the above-referenced docket.

We appreciate the Department's and OAG's thorough review of our Petition requesting recovery of our 2017 Gas Utility Infrastructure Cost Rider (GUIC) revenue requirement and Rate of Return proposal. In this Reply, we respond to the Department's Comments regarding the use of sewer conflict inspection equipment, the software costs associated with the Pipeline Data Project, the Company's sales forecast, treatment for Accumulated Deferred Income Taxes, and the Company's replacement of aging pipe. We also respond to the OAG's Comments regarding pipeline material types, main and valve replacements, risk assessment metrics, and the OAG's proposals for a revenue cap and the performance of a cost study. Finally, we respond to comments on our Rate of Return proposal.

As we explain in this Reply, the Company's Transmission Integrity Management Program (TIMP) and Distribution Integrity Management Program (DIMP) are safety-related initiatives implemented in response to state and federal regulations. Recovery of associated costs through the GUIC Rider is in the public interest, as it provides for frequent regulatory review as the Company pursues safety improvements. After reviewing Comments from the Department and the OAG, the Company has modified its request to remove costs inadvertently included in last year's GUIC filing. With that being said, our request remains largely unchanged. The Company respectfully requests recovery of $22,111,764 in projected transmission and distribution natural gas infrastructure investments and associated O&M costs for 2017, including $4.6 million in amortized costs, $27,090 lower than our original request. Also, we seek approval of our proposed risk assessment metrics, new GUIC Rider Adjustment Factors, and the true-up for 2016. Finally, we renew our recommendation of an overall rate of return (ROR) of 7.26 percent for the 2017 GUIC Rider.

REPLY

A. Comments of Department of Commerce

We appreciate the Department's conclusions that the Company has complied with its filing requirements, that the projects included in the Company's Petition are eligible for GUIC recovery, and that the variances in the Company's project costs are generally reasonable. We appreciate the Department's conclusions that the Company's revenue requirements calculations are reasonable[1], its recommendations for a tracker year ending March 31, and its recommended compliance schedule. Having reviewed the Department's Comments, there are few items in dispute. We respond to the remaining issues raised by the Department.

1. *Sewer Conflict Inspection*

The Department noted that, based on the length and cost associated with the sewer line conflict mitigation program, it wished to see a comparative analysis of the cost of owning the video equipment required to perform the conflict inspections with the cost of contracting with a third party for video inspections. As noted in the Company's response to Department Information Request No. 6, the Company did not perform a detailed cost/benefit analysis of the decision to outsource this work when it began.

The program began in response to an incident on February 1, 2010 when a sewer cleaning contractor working in Saint Paul perforated a natural gas main that intersected the sewer line, resulting in a fire, property damage, and a personal injury. The Company's remediation and mitigation plans thus arose urgently. As described in our Petition for deferred accounting treatment for the sewer conflict inspection program, the Company used a competitive bid process to minimize costs and to

[1] Please see Attachment A for a discussion responding to Table 6 in the Department's Comments at page 17.

secure qualified service providers to perform the work associated with the program. We described the process for outsourcing work as follows:

> **b. Competitive Bid Process**
> In an effort to manage the costs of our Plan, we used a competitive bid process that included issuing two Requests for Proposal ("RFP") and several rounds of supplier interviews and negotiations. We issued the first RFP to 20 suppliers for work that included numerous "bundled" work components, such as camera scoping and excavation services for those locations that cannot be "cleared" through scoping alone; very few suppliers responded to this bundled work approach, and proposed what we believed to be high costs to perform the work.
>
> We subsequently unbundled the work components in an effort to obtain a greater number of responses from more suppliers through a second RFP, which, in turn, would reduce costs through increased competition. Thirteen suppliers responded to the second RFP.
>
> Of the thirteen proposals received in response to the second RFP, we selected seven to participate in supplier interviews and negotiations. From this process, we narrowed the potential suppliers to three, and initiated another round of negotiations, from which two finalists emerged. We conducted another round of interviews and negotiations with the remaining two suppliers before finalizing our agreements with them to perform the services associated with our Plan. From the initial bids, these additional efforts progressively reduced the costs of the Plan through each round of negotiations, resulting in our selection of the least-cost, but qualified suppliers.[2]

The Commission found that the Company's approach was reasonable at the time and approved the program and its accounting treatment.

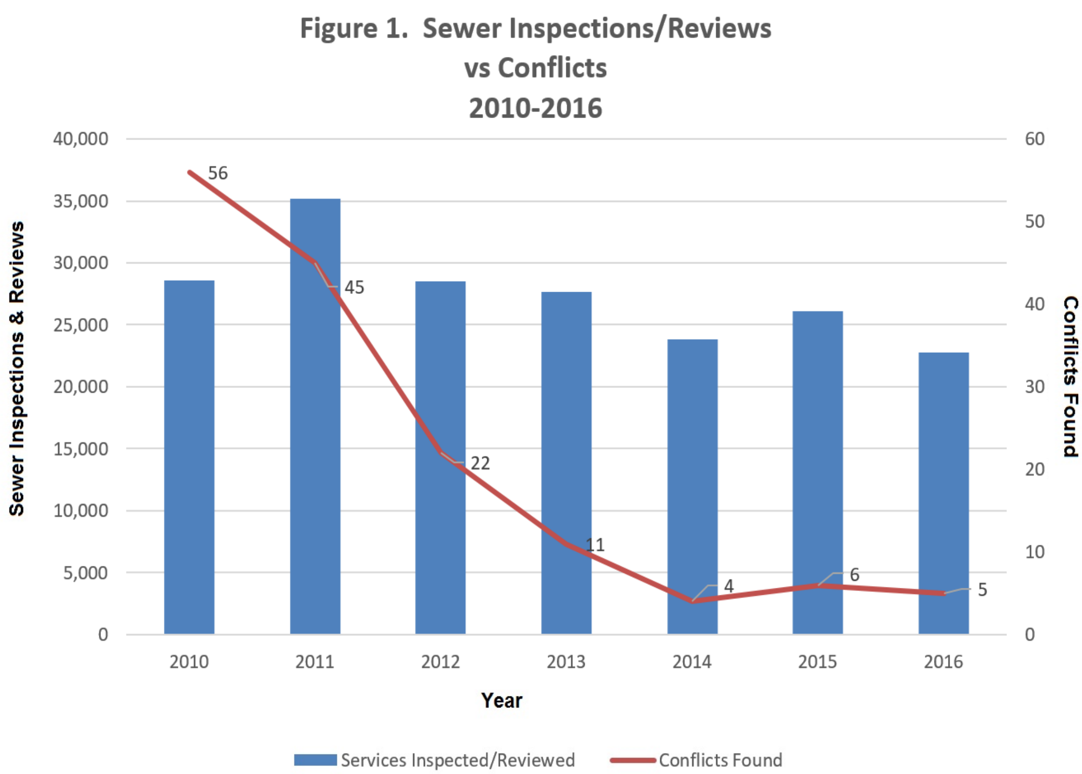
Initially, the Company anticipated that this would be a three-year program, which aligned with the timeframe to complete legacy inspections within communities of St. Paul and South St. Paul. These communities were identified as focus areas based on similar geographic characteristics as the original incident, leading to an increased likelihood of risk. Conflicts are discovered primarily through proactive camera inspections of non-utility assets or direct reports from our customers or their contractors when they are clearing a blocked sewer service.

[2] Petition for Deferred Accounting – Sewer/Natural Gas Line Conflicts, Docket No. G002-M/10-422. April 30, 2010, page 7.

During the initial three-year program, 123 conflicts were identified. The risk associated with a sewer conflict is considered to be a low probability but a high consequence. Based on the number of conflicts found during the initial three years and the significant risk posed by a single conflict, the Company determined that public safety was best served by continued inspections. The Company reviews the results of the program every year to determine whether the program should be continued the following year.

In 2016, five conflicts were identified. The Company believes the threat of conflicts with sewer laterals remains on its system and it will continue the sewer inspection program in 2017. The sewer conflict inspection work is now in the seventh year of an anticipated ten year program.

Figure 1 depicts the number of sewer inspections and the number of conflicts found since 2010. This level of risk supports the Company's continued inspection of customer sewer lines.



In order to complete this work, the Company compiles and bulk dispatches specialty work to our outside sewer inspection vendor, who is responsible to schedule, perform, document and provide videographic proof of each sewer lateral inspection to the Company. In addition to field staff, the sewer lateral inspection vendor has office personnel who supervise the field workers and provide program support to schedule customer appointments, including gaining access to customer premises in the event the inspection or potential conflict cannot be mitigated from outside.

The Company is willing to prepare a cost study of using a contractor to perform the video inspection work compared to the combined cost associated with purchasing, maintaining, and replacing equipment and hiring, training, and managing additional employees to perform the inspection work. Such a cost study would be new, and the Company would be prepared to consider the appropriate cost elements for the analysis to be included in its next GUIC Petition.

As the Company developed the program initially, it considered numerous factors when evaluating the use of a contractor. First, the sewer inspections require specialized equipment, including vehicles and specific camera equipment. The Company did not have the tools, equipment, or expertise to maintain the specialized vehicles and camera equipment needed for non-utility sewer inspection, requiring the outsourcing of the maintenance.

Second, performing this type of work with internal Company crews would have required hiring a new classification of union employees, along with the implementation of an effective training program, and acquisition of specialized safety equipment and training to protect employees from sanitary safety risks. This type of work is critical for ensuring public safety yet falls outside the Company's core utility business. Accordingly the Company sought to hire a professional contractor with the specialized resources to ensure the safety of their employees and the public.

Third, the contractor hired to perform the specialized work has familiarity with the Company's system, as well as the sanitary lines in the communities served, and has the proven expertise to conduct these types of inspections. In an effort to ensure reasonable program costs, the Company renegotiated the contract terms and conditions with the vendor, most recently in 2016. Notably, the terms of the contract include important protections for the Company which require the vendor to: obtain all licenses, permits, and inspections required for the work; stand behind its equipment, materials and labor through the provision of warranties; provide and maintain the necessary insurance for this specialized work; and indemnify the Company against third party claims and liability.

The Sewer Conflict Program is evaluated on an annual basis, and the Company shares the results with the Minnesota Office of Pipeline Safety. Although it is anticipated today that the program will run for a total of ten years, the Company will continue to evaluate the program, first from a safety risk perspective, but also considering the scope, schedule and cost of the work. As stated, the Company will perform a full comparative analysis of bringing this work in house in subsequent GUIC requests.

2. Software Costs

As part of the Company's effort to "know its assets" by identifying legacy pipe materials in Minnesota and locating and evaluating the Company's vintage distribution pipeline assets, the Company developed the Pipeline Data Project (PDP). The Department raised a concern regarding the reasonableness of the Company's PDP software costs[3]. The Company believes it has provided substantial information to demonstrate that its quality assurance and quality control activities were prudently pursued, that it did not include duplicative consulting services, and it did not shift costs. The Company agrees with the Department with respect to one item which should be removed from the Company's requested recovery.

a. Costs are properly attributed to Minnesota

On February 8, 2017, the Company responded to Department Informal Information Request No. 2 (IR DOC-2)[4], which requested the Company "[…] provide the vendor contracts and highlight the distinction between Minnesota and the Company's Operating Companies for work related to the Pipeline Data Project – Distribution GIS Data Entry." In its response, the Company provided copies of the contracts for its respective Minnesota and Colorado PDP projects. The Company described the PDP contract process and clarified how each Operating Company's scope of PDP work has unique work orders and exclusive financial terms. This ensures jurisdictional specific work is direct charged to the correct Operating Company and makes it possible to compare actual costs to contracted amounts. In the Company's Response to Informal IR DOC-2 at Attachments D and E, the Company provided work order numbers and financial terms, demonstrating the traceability of charges to jurisdiction.

In its Response, the Company further clarified that while all Operating Companies are included on the contract to expedite the contract arrangement timeline and avoid potentially extended contractual delays and additional costs, each Operating Company retains its own individualized work order for its own respective scope of work. This process is a standard practice at Xcel Energy and is not unique to the

[3] March 1, 2017 Comments of the Minnesota Department of Commerce, Docket No. G002/M-16-891, Page Nos. 12-15.
[4] Department of Commerce Informal Informational Request No. 2 and the Company's response are included here at Attachment B.

PDP project. The Company's modified request includes only costs related to the State of Minnesota.

The Department recommends a two-step allocation process for the PDP – Distribution GIS Data Entry project: first, allocate to Operating Company based on a FERC Distribution Gas allocator (FERC Accounts 870 and 880) which allocates 29.64 percent to NSPM Gas Utility; and second, allocate the NSPM Gas Utility portion to Minnesota Gas based on the TIMP allocator which allocates 88.23 percent to Minnesota. This two-step process results in a composite allocation of 26.15 percent of the total cost to the Minnesota gas jurisdiction.

The Company believes the Department's allocation of these costs is inappropriate for the following reasons: first, the work was exclusive to the State of Minnesota as shown by the map included at Attachment C. No other operating company benefited from the PDP work. Thus, no other operating company should be allocated a portion of the costs.

Second, the use of a TIMP allocator is not appropriate. The Department recommends using the TIMP allocator of 88.23 percent. However, this project is gas distribution in nature, not gas transmission, and should be classified as a DIMP project. Consistent with past practice, prior Commission orders and cost causation principles, gas distribution costs are allocated in full to the state where they are physically located, in this case 100 percent to the State of Minnesota.

b. Company supplied detailed project cost support

The Company's response to IR DOC-2 provided an itemized list of the charges sought for recovery, including the complete collection of invoices that matched actual vendor contract costs. While actual PDP project costs were $2,073,170 compared with ***[TRADE SECRET BEGINS TRADE SECRET ENDS]*** as filed, the outside vendor costs charged to the GUIC totaled ***[TRADE SECRET BEGINS TRADE SECRET ENDS]***. This is ***[TRADE SECRET BEGINS TRADE SECRET ENDS]*** than the ***[TRADE SECRET BEGINS TRADE SECRET ENDS]*** contracted amount.[5]

The Company incurred ***[TRADE SECRET BEGINS TRADE SECRET ENDS]*** of quality assurance/quality control (QA/QC) costs and ***[TRADE SECRET BEGINS TRADE SECRET ENDS]*** of miscellaneous costs. These costs, while inadvertently omitted from original filed budgets, were incurred for professional consulting services and payroll processing necessary to successfully

[5] $5,766 was invoiced under the Cyient contract for Minnesota PDP work but was not charged to the GUIC work order.

administer the program. The Company believes these costs are appropriately recoverable through the GUIC.

The role of QA/QC contractors in the PDP project was to ensure the outside vendor was interpreting the data the correct way and the end product was what the Company was expecting. The vendor was tasked with reviewing thousands of work orders, some of which were approximately 90 years old. If the vendor had a question on a certain work order vintage, the primary point of contact was the QA/QC contractor that physically worked out of the Company's offices. The role of the QA/QC contractor was that of a liaison between Company employees and the PDP contractor. The QA/QC contractor solved problems efficiently to ensure accurate results. The use of QA/QC to establish the data acceptance criteria and acceptance testing process is utilized in many different industries to ensure the vendor is performing their work the right way and that the results are acceptable. The PDP project met these criteria and we therefore chose to utilize QA/QC to ensure high quality results for our asset records.

The use of QA/QC inspection is an industry standard and a best practice at Xcel Energy in many areas and is not unique to the PDP. For example, the Company's Contractor Work Quality Inspection Program outlines QA/QC inspection requirements related to the construction of pipelines. Additionally, the Company participates in industry-sponsored committees and working groups that support QA/QC, and quality management programs, which are forums for different gas operators to share best practices. As a result of these standards and the role of PDP in supporting these projects, the Company believes QA/QC is an integral component of the integrity management programs that ensures overall quality of the asset records that play a critical role in the quality of our risk management models.

The Company acknowledges that $49,945 related to Public Service Corporation of Colorado (PSCo) capital costs were inadvertently included in the Company's last GUIC filing. Therefore, we modify the amount of our 2016 capital expenditures for the PDP project costs to $2,023,055 ($2,073,000 originally filed less $49,945 for PSCo costs included in our last GUIC filing). The Company provides supporting schedules for its revised revenue requirement at Attachment D.

c. No duplicative costs are included in the Company's request

The Company respectfully disagrees with the Department's assessment of QA/QC costs as "duplicative." The QA/QC work is critical to facilitate and validate work quality with vendors, and the QA/QC personnel serve as dedicated resources for interpreting Company work order records, some dating back to the 1920s. The group implemented a comprehensive process to ensure work was completed accurately and efficiently. The success of the Company's risk models is reliant on the quality of the asset data, like pipe type and vintage that was the focus of the PDP project.

In summary, the Company respectfully requests the Commission allow recovery of PDP project capital expenditures totaling $2,023,225. A breakdown of this request is shown below.

[TRADE SECRET BEGINS…

[TRADE SECRET ENDS….

$49,945	Non-GUIC Charges
$49,945	Total Incurred Pipeline Data Project Capital in GUIC
$49,945	Remove Non-GUIC Charges
$0	Total Requested Pipeline Data Project Capital in GUIC

3. Sales Forecast

The Department reviewed the Company's sales forecast and underlying calculations and concluded that the Company's forecasting models are generally appropriate. However, the Department also stated concerns with the Company's approach and recommended that the GUIC recovery rates be based on the Company's regression model results before monthly sales and DSM adjustments. The Department's methodology results in 0.17 percent lower sales than the Company's forecast for the proposed recovery timeframe (April 2017-March 2018), which would cause a slight increase in the average 2017 GUIC Rider rate. We have provided the illustrative schedules as requested by the Department at Attachments E and F.

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.[6]

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.[7] 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.

With respect to the Department's comments regarding the inclusion of a DSM adjustment, no evidence has been presented in this proceeding or any other proceeding that the inclusion of a gas DSM adjustment double-counts DSM. In fact, the Company's DSM adjustment is calculated in a manner to avoid any double-counting of the impacts. The Company's process assesses the amount of DSM that is embedded in the forecast because DSM achievements already are included in the historical data used for modeling. The forecast is then adjusted for only the amount that expected future DSM differs from the amount of embedded DSM. At this time, the amount of expected future DSM is less than the amount of embedded DSM. Therefore, the DSM adjustment is an addition to sales, and DSM-adjusted sales are higher than unadjusted sales. While the amount of the DSM adjustment is small[8] – the Company believes that the inclusion of the adjustment is appropriate and leads to a more accurate forecast. Therefore, the Company disagrees with the Department's recommendation to eliminate the DSM adjustment.

4. ADIT

With respect to Accumulated Deferred Income Taxes (ADIT), we are comfortable with the Department's recommendation for Commission approval of the Company's

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[6] 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.

[7] 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.

[8] The range is between +0.1 percent to +0.4 percent for the various impacted classes.

proposed ADIT proration for the forecasted year in this Petition, subject to a true-up calculation in the following year using actuals. We await the results of a pending private letter ruling from the Internal Revenue Service (IRS) to provide further guidance on this issue.

5. Equipment Replacement and Pipe Age

We appreciate the Department's suggestion regarding the pipe installation date information initially provided in discovery and later corrected. We will work to improve the quality of our information request responses in the future.

6. Compliance Filing

We do not object to the Department's recommendation of a ten day period following the Order to prepare a compliance filing with final rate-adjustment factors.

B. Comments of Office of the Attorney General

We now address the points raised by the OAG. At the outset, we note the Company is making important investments now and in the future to satisfy policy priorities in the wake of increasing concern about the country's aging pipeline infrastructure. The Commission has concluded previously that the investments made pursuant to TIMP and DIMP regulations are reasonable and prudent and that the GUIC mechanism is an enabler of public benefits.

The Rider provides added flexibility, longer- term planning horizons, more frequent regulatory review, and promptness of recovery. It does so in alignment with a rate case class cost allocation methodology. We believe the Company is appropriately using the GUIC mechanism for the purpose intended by the Legislature, and with the approval of the Commission. We respond to the OAG's Comments, including those addressing pipeline material types, main and valve replacement, current risk assessment, proposed metrics, a proposed revenue cap, and the Company's cost study.

1. Pipeline Material Types

The OAG presented information regarding the types of pipes in service in other parts of the country. It is important to understand that the DIMP requires that each operator knows the risk profile and threats specific to its own system and develops mitigation plans to address those specific risks.

While the OAG correctly notes that the Company has replaced all of its known cast iron pipe and has very little bare steel pipe, the Company recognizes the risk associated with other vintage pipe types, too, and builds its integrity management plans to systematically mitigate those known risks. The Company has long taken a proactive stance and developed a supporting strategy for ensuring public safety by replacing poor performing pipe. It is our view that this proactive approach to safety investments should be favorably recognized.

While the OAG highlights a 1998 National Transportation Safety Board (NTSB) report to support the idea that the public safety risk associated with plastic pipe materials has been "overstated," the focus of the report is to highlight the risks associated with plastic pipe materials in the context of other factors.[9]

From the abstract of the 1998 report[10]:

> Despite the general acceptance of plastic piping as a safe and economical alternative to piping made of steel or other materials, the National Transportation Safety Board notes that a number of pipeline accidents it has investigated have involved plastic piping that cracked in a brittle-like manner. This special investigation report concludes that the procedure used in the United States to rate the strength of plastic pipe may have overrated the strength and resistance to brittle-like cracking of much of the plastic pipe manufactured and used for gas service from the 1960s through the early 1980s. As a result, much of this piping may be susceptible to premature brittle-like failures when subjected to stress intensification, and these failures represent a potential public safety hazard.

As this report and others have indicated, pipe type alone does not present a complete picture of risk or risk mitigation. Factors like couplings, installation methods, and many others impact the safety risk posed, as well as the need for replacement.

The OAG similarly highlights its view that one type of pipe poses little to no risk "if left undisturbed."[11] We note that many other factors bear on this risk, such as methods used to join cast iron pipe and vintage plastic or steel. For example, frost heave and degradation of materials used in aging fittings contribute to leakage and failures. The Company also notes that there are many factors outside its control around its gas system. While it is possible that the Company can chose to leave a

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[9] March 1, 2017, Comments of the Office of the Attorney General, Docket No. G002/M-16-891, page 20.
[10] *U.S. Dep't of Transportation, Nat'l Transportation Safety Board, Special Investigation Report: Brittle-Like Cracking in Plastic Pipe for Gas Service* (1998).
[11] OAG Comments, page 21.

vintage material "undisturbed", it cannot ensure that others within the community will do so. These natural and third party impacts can have negative consequences on materials prone to brittle failure. For this reason, the Company has chosen to systematically address these known poor performing vintage assets.

The Company takes all of these factors, not just pipe material, into consideration when planning integrity projects. The OAG points to an approach in Arkansas where state statute directs activity at replacement of specific material types.[12] We believe the Company's approach, which relies on a holistic view of factors that contribute to the overall risk profile of specific gas infrastructure, rather than looking narrowly at material type alone, is consistent with Minnesota law and provides a more constructive framework for assessing risk and planning mitigation strategies.

2. Main Replacement

In its comments, the OAG presents in Figure 3 the miles of pipeline replaced in years 2010 through 2016 and suggests that some GUIC projects are already recovered via base rates established in 2010.[13] The OAG acknowledges that the data shown includes *all* replacement activity, including relocations and abandonments for activities not associated with pipeline renewal.

The OAG implies that the regulatory requirements driving the Company's integrity management may not have increased the rate of main replacement and that costs for these activities may be double-recovered. When the Commission issued its *Order Approving Rider with Modifications* in Docket No. G002/M-14-336, it approved of GUIC recovery for incremental costs of the main replacement work conducted pursuant to the integrity management programs. As the Commission found again in Docket No. G002/M-15-808,

> The Commission concurs with the Department that the investments proposed for rider recovery—including the new FCM project—meet the statutory requirements for rider recovery as gas utility infrastructure costs. These costs were incurred in the replacement or modification of existing facilities required by federal and state agencies. They were not included in Xcel's last rate case. And the costs are reasonable and prudent in view of the public safety purpose served by the TIMP and DIMP initiatives.[14]

The OAG Comments here do not support any different conclusion.

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[12] OAG Comments, page 30, FN 91.
[13] OAG Comments, page 28.
[14] Commission Order Approving Rider Recovery, August 18, 2016, Docket No. G002/M-15-808, page 6.

3. Distribution Valve Replacement

The OAG discusses the Company's Distribution Valve Replacement Project in relation to overall customer impact. The Company's Petition provides the regulation pertaining to the Distribution Valve Replacement Project on page 11 of Attachment C. These valves provide for shut down of sections of the gas system in the event of an emergency and can help limit the number of customers impacted in these events. The Company is replacing valves at a faster than historic rate, again working to improve the overall safety of the gas system at a quicker pace than historically performed.

In addition to timing projects based on response to regulatory requirements and the results of assessments, our projects are timed to capture efficiency gains when addressing needed investments. When work can be coordinated in a systematic, proactive manner, rather than a reactive or emergent manner, there are opportunities to optimize the coordination of the project.[15] Construction work planned proactively can reduce mobilization costs, coordinate permitting and street construction with impacted communities, and minimize traffic rerouting. These efficiencies are enabled by the Rider's forward-looking budget and longer-term view. Thus, the use of the Rider mechanism for distribution valve and main replacements is a benefit to customers and the public.

4. Current Risk Assessment

The OAG addressed both the Company's current risk assessment methodology, as well as the metrics specifically proposed by the Company in compliance with the Commission's Order. In its comments addressing current risk assessment practices, the OAG states that the Company did not describe how the coated steel and Aldyl-A assessment projects were identified and asserts that they were scored using inconsistent methods. To the contrary, in the Company's 2017 Petition, Attachment C2(a), the risk scoring methodology for both Problematic Steel and Aldyl-A are presented in detail, as well as what constitutes high and medium risk designations.

The resulting risk scores for each project are different for important reasons. The nature of the risks and causal factors for each project type are different and the

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[15] An example of a replacement activity conducted in a reactive, rather than proactive, manner is when MNOPS mandated the replacement of all Century pipe, a brand of plastic pipe subject to cracking, following a safety-related event. This is detailed in the Risk Assessment Metrics discussion. PHMSA issued an advisory bulletin to all operators about the risk of that particular brand of polyethylene pipe. See PHMSA's Letter from Cynthia L. Quarterman to the National Association of Regulatory Utility Commissioners in support of rate mechanisms that will encourage and will enable pipeline operators take reasonable measures to repair, rehabilitate or replace high-risk gas pipeline infrastructure, included at Attachment G.

appropriate data sources are thus different. Given how distinguishable the risks presented by these materials are, a one-size-fits-all algorithm is not practical or appropriate. Instead, the Company applies its risk assessment methodology to the actual conditions.

The OAG states that it is impossible to know, based on the sample of risk scores, whether the Company is prudently selecting the highest-risk candidates for removal. The Company has demonstrated in its 2017 Petition, Attachment C2(a), page 2, that it applies a risk methodology for vintage steel distribution pipe that uses logical causal factors (such as the number of prior leaks). As the Company demonstrated, this approach shows that only 3.66 percent of the possible projects score as high or medium risk.

The Company has also clearly demonstrated the prudency and scope of its problematic plastic projects, as well as the regulatory requirements that give rise to the replacement program. Attachment C2(a), page 3 shows that high and medium risk problematic plastic is comprised solely of low-ductile inner wall Aldyl-A piping manufactured by DuPont Company before 1973, Century MDPE 2306, HDPE 3306 or Dylon. In the Supplement to the Company's Petition, the Company provided the regulations associated with each project in Table 2. As shown, the PHMSA Advisory Bulletins pertain directly to this early generation plastic.

5. Proposed Metrics

In its August 18, 2016 Order, the Commission directed the Company to 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. The Commission ordered the Company to develop the metrics after considering to what degree parties understand the Company's assets and system risks. The Commission directed that each metric should include a reconciliation to the pertinent TIMP/DIMP rules, or if not tied to TIMP/DIMP requirements, the goal, benefit, or requirement it addresses.

The Company fulfilled the requirements set forth in the Order. The Company proposed metrics and provided reconciliation to the pertinent TIMP/DIMP rules in Table 2 of its January 13, 2017 Supplement. The Company also met with representatives from the OAG, the Department, the Commission, and MNOPS on November 16, 2016 to present proposed metrics and host a discussion with stakeholders on the proposal. The Company followed up with an opportunity for stakeholders to provide input via email following the meeting. The OAG, by email, expressed its interest in a means of determining the appropriate amount of risk that is removed each year by GUIC projects. The Company believes its proposed metrics are responsive to this feedback.

In follow-up to the discussion with stakeholders, the Company is in the process of seeking input from other utilities on performance metrics in use in other jurisdictions through the American Gas Association's SOS forum. The Company can confirm that the OAG's feedback is included in the survey questions. Please see the AGA SOS survey at Attachment H. We look forward to sharing the result of this survey.

In its Comments, the OAG states that "if a metric was developed that assigned a system risk score, and that score indicated an elevated system risk, then the Commission could work toward establishing a target score for the system and then work to determine the annual cost to achieve the target score."[16] The OAG further argues that "the Commission should set a target and allow utilities to demonstrate that it is meeting the target in a cost-effective manner." The OAG also asks the Commission to require the Company to participate in a separate docket on performance metrics, a "significant undertaking", that should include other Minnesota utilities.

The Company agrees that such an undertaking would indeed take time and resources from all parties and run the risk of yielding no superior results than those metrics proposed by the Company. The Company believes the Commission has actionable metrics before it, and should adopt the Company's proposed metrics, not as a "go-no-go" target score, but instead as a useful framework for evaluating the safety performance of the pipeline. With the metrics in place, investments can be evaluated in concert with the need and benefits of the DIMP and TIMP programs of work.

In discussion of the Company's proposal for the use of leak rates as the metric for DIMP, the OAG states that "simply tracking the leak rate of a particular pipe material over time, as Xcel proposes to do here, does not provide any valuable information." The Company believes that monitoring leak rates is the most appropriate performance measure for DIMP activities, and this conclusion is supported by the National Regulatory Research Institute and is a requirement in federal regulations. The National Regulatory Research Institute report cited in this record states "to reduce leaks, an appropriate metric is the leaks per mile." Additionally, 49CFR Part 192.1007(e) requires performance metrics for DIMP that include the number of leaks either eliminated or repaired, categorized by cause. The DIMP metric proposed by the Company includes a very similar metric of leak rate by material vintage to be monitored over time. We would urge the Commission to adopt this well-accepted DIMP metric.

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[16] OAG Comments, page 42.

The OAG expresses concerns that the DIMP cost-effectiveness metrics proposed by the Company "did not describe why one standard deviation is a reasonable, industry standard measure". The use of standard deviation to measure the statistical significance of a population of outcomes is common in many industries.[17] DIMP projects costs have inherently high variability. For example, differences in soil conditions, paving requirements, traffic control, and permit restrictions on hours of work are all factors with significant bearing on project costs. Standard deviation is a means of ensuring those costs far from the average may be systematically identified and evaluated. The Company believes this is a reasonable application of a common industry standard.

The OAG expresses concerns that the TIMP metric proposed by the Company "would seem to be an unreliable metric given the drastic, seemingly random swings in the number of anomalies repaired by the Company". The nature of an "anomaly" is that it deviates from what is standard, normal, or expected. As stated in the Company's Supplement and Compliance Metrics Proposal, 84 percent of the capital and O&M spend proposed for 2017 TIMP projects is for projects that detect and repair pipe anomalies. It is therefore natural that the most meaningful metric is based on anomalies, regardless of frequency.

The Company is active nationally with PHMSA and shares best practices with peer gas utilities across the U.S. The natural gas industry is working on establishing leading indicators for the effectiveness of integrity management programs. The Company will continue to implement industry best practices as they are in the best interest of public safety. Additionally, we expect performance metrics and leading indicators to evolve over time. The Company will share the results of these efforts with the Commission and with the stakeholders in this proceeding.

TIMP and DIMP are undertaken to reduce the likelihood of a significant gas incident that may result in injury to the public or damage to property by enacting preventative and mitigative measures to reduce the likelihood or severity of gas leaks and pipeline ruptures. The Company has proposed workable metrics that enable the evaluation and prioritization of projects pursuant to these goals, and we request that the Commission approve the Company's metrics.

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[17] Analysis of standard deviation is common in manufacturing processes. A manufacturing process is a unique combination of tools, materials, methods, and people engaged in producing a measurable output; for example a manufacturing line for machine parts. The outcome being evaluated may be the labor required to assemble the machine part which may be influenced by any number of factors. The use of standard deviation creates understanding of how often and by what amount the actual labor varies from the mean. This analysis allows for the identification of labor that is outside of what is normally expected and warrant closer examination.

6. Revenue Cap

As demonstrated by our GUIC proposals in 2014, 2015, and 2016, the Company plans our safety investments carefully. We plan a year's worth of GUIC activity, then we seek permission for cost recovery of that activity, then we undertake the activity, we report on the outcome of the activity, and finally, we true-up the surcharge to reflect actual costs. We work closely with regulators throughout this process to ensure adequate controls are in place and cost levels are reviewed annually.

Despite this, the OAG again proposes a limit for Rider cost recovery at six percent of base revenues. We do not support an overall limitation on cost recovery through the Rider. First, the six percent level is set arbitrarily. The OAG provided no support for the basis of its proposed cap last year, nor does it present any evidence of its reasonableness in the context of the GUIC again this year.

Second, the Legislature was clear in its intent to incentivize utility safety investments. The pipeline safety legislation at Minn. Stat. § 216B.16 Subd. 11 states that, "**[a]ll costs** of a public utility that are necessary to comply with state pipeline safety programs […] must be recognized and included by the commission in the determination of just and reasonable rates as if the costs were directly incurred by the utility in furnishing utility service." (Emphasis added). This language makes clear that all costs that are necessary must be included. The GUIC was the mechanism identified by the Legislature for utility cost recovery of these investments. The OAG's proposal would be in direct conflict with statute.

Third, there are significant practical considerations that do not align with a cost recovery limit. For example, under the OAG's proposed cap, the Company would potentially be unable to recover costs of important safety projects because of investments already made. Such an outcome is directly contrary to the purpose of the GUIC statute, which was intended to incentivize gas utility companies to make necessary safety investments. The statute does not seek to incentivize gas utilities to only make safety investments up to a cap, or to make initial investments and then abruptly terminate recovery. We urge the Commission to again reject the OAG's unfounded cap proposal.

7. Cost Study

With respect to the detail provided about utility costs and revenue, the OAG suggests both that the Company has not complied with the Commission's order requiring a reconciliation of GUIC activities with base rates, and alternatively, that the Company has complied but the Commission's Order is insufficient.

The Company filed Attachment J, 2015 Annual Report/GUIC Reconciliation, in response to the Commission's August 18, 2016 Order (G-002/GR-15-808) point #11:

> As part of Xcel's next GUIC petition, the Company shall file a cost/revenue study based on 2015 actuals reconciled back to Xcel's 2015 Jurisdictional Annual Report.

In the last GUIC docket, the OAG and the Commission staff expressed concerns of the potential that the Company is over-earning. Attachment J reconciles to the Company's 2015 Jurisdictional Annual Report all-in revenue deficiency of $6.8 million which includes base rate, PGA, and GUIC recovery. The Company is not in an over-earnings position.

The OAG's comments suggest that Attachment J does not provide enough detail or narrative of the results to address concerns about over-earning nor does it address the specific questions raised by Commission's staff in last year's briefing papers. Questions posed by staff were not included in the Commission's order and significant detail is provided by the Company's 2015 Jurisdictional Annual Report and Attachment J.

Attachment J provides all of the typical numbers included in a Cost of Service Study summary including:

- Rate base with detail for:
    - Plant in Service,
    - Depreciation Reserve,
    - Construction Work in Progress,
    - Accumulated Deferred Income Taxes,
    - Other Rate Base items with detail for:
        - Cash Working Capital,
        - Materials and Supplies,
        - Fuel Inventory,
        - Non-plant Assets and Liabilities,
        - Prepaids and Other,
        - Regulatory Amortizations,
- Operating Revenues
- Operating Expenses with detail for:
    - Production
    - Purchased Gas
    - Natural Gas Storage

  - Gas Transmission
  - Gas Distribution
  - Customer Accounting
  - Customer Service & Information
  - Sales, Econ Dvlp & Other
  - Administrative & General
- Book Depreciation,
- Amortization Expense,
- Taxes with detail for:
  - Federal Income Taxes,
  - State Income Taxes,
  - Property Taxes
  - Deferred Income Tax
  - Payroll & Other Taxes
- Net Income,
- Revenue Deficiency, and
- Revenue Requirements

Attachment J provides cross-references to the 77 pages of additional detail that was filed in the 2015 Gas Jurisdictional Annual Report submitted April 29, 2016 in Docket No. E,G999/PR-16-4, a copy of which is provided as Attachment I. As the Company described in its Petition, the 2015 GUIC revenue requirements are less than 3 percent of the calculated 2015 Annual Report revenue requirements.

The OAG once again attempts to support its positions on GUIC recovery by referencing inapplicable federal standards. The OAG cites to the Federal Energy Regulatory Commission (FERC), a body which does not have authority over the Company's GUIC proposal. We believe the Company's GUIC request satisfies Minnesota's applicable standards.

C. Rate of Return

The GUIC statute states that "[t]he return on investment for the rate adjustments shall be at the level approved by the commission in the public utility's last general rate case, unless the commission determines that a different rate of return is in the public interest." Minn. Stat. § 216B.1635 Subd. 6. Based on the Company's additional analysis of the ROR, we continue to support an ROR of 7.26 percent as being in the public interest.

The Company's 7.26 percent return is based on the capital structure and cost of debt approved in the Company's 2015 GUIC Rider (Docket No. G-002/M-15-808), and the Company's proposed 9.50 percent return on equity (ROE) as supported by the Company's expert. The Department concludes that the Company's proposal to calculate its weighted average cost of capital using the capital structure and cost of debt approved in its 2015 GUIC Rider is reasonable.

As described in our November 1, 2016 filing, the Company retained ScottMadden, Inc. ("ScottMadden"), to perform an assessment of the appropriateness of the Company's proposed 9.50 percent ROE in the ROR calculation for the GUIC Rider. In that filing, ScottMadden concluded that the Company's proposed 9.50 percent ROE was reasonable.

Additionally, the Company's proposed 9.50 percent ROE falls well within the Department's range. As shown in Appendix A, Table 5 of the Department's Comments, the Department's estimated Weighted ROE Range is 7.38 percent (Low Mean ROE) to 10.79 percent (High Mean ROE), with a Mean ROE of 9.04 percent. The Company's proposed 9.50 percent ROE is below the midpoint of the Mean and High Mean ROE results, and from that perspective, finds support in the Department's ROE range.

Further, the proposed 9.50 percent ROE is consistent with ROEs recently authorized for natural gas utilities in other jurisdictions (*see*, Table 10 in Attachment S of the Company's filing). Based on data from Regulatory Research Associates, the average authorized ROE for natural gas utilities from January 1, 2015 to September 30, 2016 was 9.525 percent. Public utility commissions authorized an ROE of 9.50 percent, or higher, in more than two-thirds of the natural gas rate cases during this time period (22 out of 32 cases). More recently (from September 30, 2016 to February 28, 2017), the average authorized ROE for natural gas utilities was 9.53 percent.

Based on this data, the OAG's 7.13 percent ROE recommendation is plainly well below any reasonable estimate, and should not be given any consideration by the Commission.

CONCLUSION

Xcel Energy respectfully requests that the Commission, consistent with its previous Orders, grant recovery of the Company's gas utility infrastructure costs through a GUIC Rider and approve the proposed 2017 GUIC Rider factors. In its Petition, the Company described its reasonable and prudent investments in pipeline safety planning and outlined its cost recovery proposal for these investments. The Company has proposed metrics for assessing the relative priority of safety investments. We believe the proposed metrics are effective tools to enable Company project prioritization and regulatory review. The Company also appreciates the Department's thoughtful analysis on the ROR, and we continue to support our proposed ROR of 7.26 percent.

Dated: March 13, 2017

Northern States Power Company

Decrease in Revenue Requirements

In Table 6, Page 17 of Comments submitted March 1, 2017, the Department of Commerce identifies an overall decrease in revenue requirements for TIMP and DIMP projects from the previous GUIC Rider filing (Docket No. G002/M-15-808) to the current filing (Docket No. G002/M-16-891).

We note that the numbers provided by the Department in Table 6 are not directly comparable. The 15-808 revenue requirement amounts exclude the true-up and base rate removals, whereas the 16-891 amounts show total revenue requirements. The Company provides an updated comparison below which excludes the true-up, base rate removals, and ADIT pro-rate in both dockets:

Docket No.	2016	2017	2018	2019	2020	2021
15-808	$17.9	$23.8	$27.1	$33.4	$32.3	N/A
16-891	$17.3	$22.2	$25.1	$30.9	$29.0	$34.7
Change	($0.6)	($1.5)	($2.0)	($2.5)	($3.2)	N/A

The overall decreases in revenue requirements are being driven by the following:

1. Lower ROE in the current filing:
    - 15-808 included an ROE of 10.09%
    - 16-891 includes an ROE of 9.64% in 2016 and 9.5% in 2017-2021
    - This change accounts for roughly 25% of the total decreases shown above

2. Bonus Depreciation:
    - On December 18, 2015, the President signed the Protecting Americans from Tax Hikes (PATH) Act of 2015 into law, which extended bonus depreciation.
    - Bonus depreciation is the immediate expensing of 50% for property placed in service in 2015, 2016, and 2017; 40% for property placed in service in 2018; and 30% for property placed in service in 2019.
    - Although the overall change in Plant-in-Service increases in 2016-2021, the total change in Rate Base decreases significantly due to increases in Accumulated Deferred Taxes (an off-set to Rate Base) which is caused by the bonus depreciation.

We have provided a detailed comparison of revenue requirement amounts for both TIMP and DIMP projects between the previous year's filing and the current filing as Page 2 of this attachment.

Comparison of Revenue Requirements for TIMP and DIMP Projects - Docket Nos. G002/M-15-808 and G002/M-16-891

	15-808 TIMP					
	2015	2016	2017	2018	2019	2020
Rate Base						
CWIP	-	-	-	-	-	-
Plant In-Service	34,667,769	62,381,683	68,178,116	94,531,909	126,834,670	160,618,092
++	937,260	2,028,481	3,566,433	5,283,542	7,440,821	10,155,720
Less Accumulated Deferred Taxes	3,510,592	4,292,194	5,816,274	7,677,839	10,300,401	13,727,730
End Of Month Rate Base	**30,219,918**	**56,061,007**	**58,795,408**	**81,570,528**	**109,093,448**	**136,734,641**
Return on Rate Base						
Debt Return	469,695	885,585	1,284,856	1,477,126	2,034,107	2,736,013
Equity Return	1,096,645	2,067,665	2,999,885	3,448,797	4,749,236	6,388,048
Total Return on Rate Base	**1,566,340**	**2,953,249**	**4,284,741**	**4,925,923**	**6,783,343**	**9,124,062**
Income Statement Items						
AFUDC Pre-Eligible	-	-	-	-	-	-
Operating Expenses	1,019,711	-	1,413,734	1,004,467	1,494,948	1,491,459
Property Taxes	403,656	638,992	1,149,812	1,256,651	1,742,401	2,337,802
Book Depreciation	617,660	1,091,221	1,537,952	1,717,109	2,157,278	2,714,900
Deferred Taxes	469,315	781,603	1,524,080	1,861,564	2,622,562	3,427,330
Gross Up for Income Tax	295,485	662,467	561,389	532,666	671,246	1,003,780
Carryover	-	-	-	-	-	-
Total Income Statement Expense	**2,805,827**	**3,174,283**	**6,186,967**	**6,372,458**	**8,688,435**	**10,975,270**
Revenue Requirement						
Total	**4,372,167**	**6,127,532**	**10,471,708**	**11,298,381**	**15,471,778**	**20,099,332**

	15-808 DIMP					
	2015	2016	2017	2018	2019	2020
Rate Base						
CWIP	-	-	-	-	-	-
Plant In-Service	11,780,258	22,342,374	39,935,764	57,127,051	74,112,996	91,975,109
++	118,725	472,653	1,157,741	2,288,946	3,851,970	5,833,883
Less Accumulated Deferred Taxes	379,188	731,102	1,449,479	2,580,424	4,058,244	5,881,730
End Of Month Rate Base	**11,282,345**	**21,138,618**	**37,328,543**	**52,257,681**	**66,202,783**	**80,259,496**
Return on Rate Base						
Debt Return	80,455	340,037	614,863	974,598	1,302,929	1,602,228
Equity Return	187,847	793,919	1,435,584	2,275,494	3,042,080	3,740,885
Total Return on Rate Base	**268,302**	**1,133,956**	**2,050,447**	**3,250,092**	**4,345,008**	**5,343,113**
Income Statement Items						
AFUDC Pre-Eligible	-	-	-	-	-	-
Operating Expenses	3,668,777	4,637,500	4,251,470	4,251,470	3,978,970	578,970
Property Taxes	19,025	217,132	411,812	736,091	1,052,959	1,366,042
Book Depreciation	153,341	703,152	1,034,312	1,480,429	1,912,248	2,266,907
Deferred Taxes	166,495	351,914	718,377	1,130,945	1,477,819	1,823,486
Gross Up for Income Tax	(37,895)	199,942	277,559	447,862	633,678	772,903
Carryover	-	-	-	-	-	-
Total Income Statement Expense	**3,969,744**	**6,109,641**	**6,693,530**	**8,046,797**	**9,055,674**	**6,808,308**
Revenue Requirement						
Total	**4,238,046**	**7,243,597**	**8,743,977**	**11,296,889**	**13,400,683**	**12,151,421**

	15-808 Base Rate Credit, ADIT Prorate, Carryover					
	2015	2016	2017	2018	2019	2020
Rate Base						
CWIP	-	-	-	-	-	-
Plant In-Service						
++						
Less Accumulated Deferred Taxes						
End Of Month Rate Base	**-**	**-**	**-**	**-**	**-**	**-**
Return on Rate Base						
Debt Return						
Equity Return						
Total Return on Rate Base	**-**	**-**	**-**	**-**	**-**	**-**
Income Statement Items						
AFUDC Pre-Eligible	-	-	-	-	-	-
Operating Expenses	(480,000)	(480,000)	(480,000)	(480,000)	(480,000)	(480,000)
Property Taxes						
Book Depreciation						
Deferred Taxes						
Gross Up for Income Tax						
Carryover		(1,935,343)				
Total Income Statement Expense	**(480,000)**	**(2,415,343)**	**(480,000)**	**(480,000)**	**(480,000)**	**(480,000)**
Revenue Requirement						
Total	**(480,000)**	**(2,415,343)**	**(480,000)**	**(480,000)**	**(480,000)**	**(480,000)**

	15-808 TOTAL					
	2015	2016	2017	2018	2019	2020
Rate Base						
CWIP	-	-	-	-	-	-
Plant In-Service	46,448,027	84,724,056	108,113,879	151,658,959	200,947,666	252,593,201
++	1,055,985	2,501,134	4,724,174	7,572,488	11,292,791	15,989,603
Less Accumulated Deferred Taxes	3,889,780	5,023,297	7,265,753	10,258,263	14,358,644	19,609,460
End Of Month Rate Base	**41,502,262**	**77,199,626**	**96,123,951**	**133,828,208**	**175,296,231**	**216,994,137**
	-	-	-	-	-	-
Return on Rate Base	-	-	-	-	-	-
Debt Return	550,150	1,225,622	1,899,719	2,451,725	3,337,035	4,338,241
Equity Return	1,284,492	2,861,584	4,435,468	5,724,291	7,791,316	10,128,934
Total Return on Rate Base	**1,834,642**	**4,087,205**	**6,335,188**	**8,176,015**	**11,128,352**	**14,467,175**
	-	-	-	-	-	-
Income Statement Items	-	-	-	-	-	-
AFUDC Pre-Eligible	-	-	-	-	-	-
Operating Expenses	4,208,488	4,157,500	5,185,204	4,775,937	4,993,918	1,590,429
Property Taxes	422,681	856,125	1,561,624	1,992,742	2,795,360	3,703,844
Book Depreciation	771,001	1,794,373	2,572,264	3,197,538	4,069,526	4,981,807
Deferred Taxes	635,810	1,133,517	2,242,457	2,992,509	4,100,381	5,250,816
Gross Up for Income Tax	257,590	862,409	838,948	980,528	1,304,924	1,776,683
Carryover	-	(1,935,343)	-	-	-	-
Total Income Statement Expense	**6,295,571**	**6,868,581**	**12,400,497**	**13,939,254**	**17,264,109**	**17,303,578**
	-	**-**	**-**	**-**	**-**	**-**
Revenue Requirement	-	-	-	-	-	-
Total	**8,130,213**	**10,955,786**	**18,735,685**	**22,115,270**	**28,392,460**	**31,770,753**

	16-891 TIMP					
	2015	2016	2017	2018	2019	2020
Rate Base						
CWIP	-	-	-	-	-	-
Plant In-Service	41,643,044	62,241,772	67,485,509	94,304,472	126,992,231	158,303,598
Less Accumulated Book Depreciation Reserve	976,013	2,173,115	3,707,394	5,431,003	7,623,333	10,309,518
Less Accumulated Deferred Taxes	7,449,615	12,191,892	13,920,161	19,031,590	24,254,789	26,268,606
End Of Month Rate Base	**33,217,416**	**47,876,765**	**49,857,955**	**69,841,879**	**95,114,110**	**121,725,475**
Return on Rate Base						
Debt Return	466,692	849,227	1,097,683	1,274,686	1,801,048	2,389,865
Equity Return	1,089,634	1,892,991	2,412,969	2,802,063	3,959,132	5,253,492
Total Return on Rate Base	**1,556,326**	**2,742,219**	**3,510,653**	**4,076,749**	**5,760,179**	**7,643,357**
Income Statement Items						
AFUDC Pre-Eligible	-	-	-	-	-	-
Operating Expenses	1,278,010	177,148	1,146,990	1,003,135	1,492,870	1,495,074
Property Taxes	403,656	767,560	1,147,233	1,243,885	1,738,209	2,340,706
Book Depreciation	656,413	1,197,102	1,534,279	1,723,610	2,192,329	2,686,185
Deferred Taxes	4,408,336	4,742,277	1,728,269	5,111,429	5,223,199	2,013,817
Gross Up for Income Tax	(3,741,717)	(3,514,969)	(61,775)	(3,250,582)	(2,548,550)	1,650,237
Carryover						
Total Income Statement Expense	**3,004,700**	**3,369,117**	**5,494,995**	**5,831,477**	**8,098,057**	**10,186,018**
Revenue Requirement						
Total	**4,561,025**	**6,111,336**	**9,005,648**	**9,908,226**	**13,858,236**	**17,829,375**

	16-891 DIMP					
	2015	2016	2017	2018	2019	2020
Rate Base						
CWIP	-	-	-	-	-	-
Plant In-Service	12,064,627	24,690,429	42,817,984	59,576,677	76,404,531	93,229,775
Less Accumulated Book Depreciation Reserve	111,172	494,133	1,228,756	2,421,035	4,034,638	6,060,786
Less Accumulated Deferred Taxes	2,236,825	4,511,170	8,376,728	11,480,212	14,079,004	14,899,908
End Of Month Rate Base	**9,716,630**	**19,685,126**	**33,212,500**	**45,675,430**	**58,290,889**	**72,269,081**
Return on Rate Base						
Debt Return	54,823	295,021	550,015	858,149	1,139,829	1,429,762
Equity Return	128,001	657,625	1,209,063	1,886,415	2,505,616	3,142,958
Total Return on Rate Base	**182,824**	**952,646**	**1,759,077**	**2,744,564**	**3,645,445**	**4,572,721**
Income Statement Items						
AFUDC Pre-Eligible	-	-	-	-	-	-
Operating Expenses	3,542,056	4,437,500	4,551,000	4,251,000	3,979,000	579,000
Property Taxes	19,025	222,374	455,091	789,216	1,098,110	1,408,279
Book Depreciation	81,558	650,327	1,162,416	1,620,071	2,041,395	2,453,941
Deferred Taxes	2,024,132	2,274,346	3,865,557	3,103,484	2,598,792	820,903
Gross Up for Income Tax	(1,981,796)	(1,864,232)	(3,104,062)	(1,845,976)	(892,404)	1,377,347
Carryover						
Total Income Statement Expense	**3,684,976**	**5,720,314**	**6,930,002**	**7,917,796**	**8,824,894**	**6,639,470**
Revenue Requirement						
Total	**3,867,799**	**6,672,961**	**8,689,079**	**10,662,360**	**12,470,339**	**11,212,191**

	16-891 Base Rate Credit, ADIT Prorate, Carryover					
	2015	2016	2017	2018	2019	2020
Rate Base						
CWIP	-	-	-	-	-	-
Plant In-Service						
Less Accumulated Book Depreciation Reserve						
Less Accumulated Deferred Taxes						
End Of Month Rate Base	**-**	**-**	**-**	**-**	**-**	**-**
Return on Rate Base						
Debt Return						
Equity Return						
Total Return on Rate Base	**-**	**-**	**-**	**-**	**-**	**-**
Income Statement Items						
AFUDC Pre-Eligible	-	-	-	-	-	-
Operating Expenses	(480,000)	(480,000)	(480,000)	(480,000)	(480,000)	(480,000)
Property Taxes						
Book Depreciation						
Deferred Taxes	-	134,029	108,767	156,574	153,016	55,916
Gross Up for Income Tax						
Carryover			(1,184,983)	261,276		
Total Income Statement Expense	**(480,000)**	**(345,971)**	**(1,556,216)**	**(62,150)**	**(326,984)**	**(424,084)**
Revenue Requirement						
Total	**(480,000)**	**(345,971)**	**(1,556,216)**	**(62,150)**	**(326,984)**	**(424,084)**

	16-891 TOTAL					
	2015	2016	2017	2018	2019	2020
Rate Base						
CWIP	-	-	-	-	-	-
Plant In-Service	53,707,671	86,932,201	110,303,494	153,881,150	203,396,762	251,533,373
Less Accumulated Book Depreciation Reserve	1,087,185	2,667,248	4,936,150	7,852,038	11,657,970	16,370,304
Less Accumulated Deferred Taxes	9,686,440	16,703,062	22,296,889	30,511,802	38,333,793	41,168,513
End Of Month Rate Base	**42,934,047**	**67,561,891**	**83,070,455**	**115,517,309**	**153,404,998**	**193,994,556**
	-	-	-	-	-	-
Return on Rate Base	-	-	-	-	-	-
Debt Return	521,515	1,144,249	1,647,698	2,132,835	2,940,877	3,819,628
Equity Return	1,217,634	2,550,616	3,622,032	4,688,478	6,464,748	8,396,450
Total Return on Rate Base	**1,739,149**	**3,694,865**	**5,269,730**	**6,821,313**	**9,405,625**	**12,216,077**
	-	-	-	-	-	-
Income Statement Items	-	-	-	-	-	-
AFUDC Pre-Eligible	-	-	-	-	-	-
Operating Expenses	4,340,067	4,134,648	5,217,990	4,774,135	4,991,870	1,594,074
Property Taxes	422,681	989,933	1,602,324	2,033,101	2,836,319	3,748,985
Book Depreciation	737,972	1,847,429	2,696,695	3,343,681	4,233,724	5,140,126
Deferred Taxes	6,432,468	7,150,651	5,702,593	8,371,487	7,975,007	2,890,636
Gross Up for Income Tax	(5,723,513)	(5,379,201)	(3,165,838)	(5,096,558)	(3,440,954)	3,027,584
Carryover	-	-	(1,184,983)	261,276	-	-
Total Income Statement Expense	**6,209,675**	**8,743,460**	**10,868,782**	**13,687,123**	**16,595,967**	**16,401,405**
	-	**-**	**-**	**-**	**-**	**-**
Revenue Requirement	-	-	-	-	-	-
Total	**7,948,824**	**12,438,325**	**16,138,512**	**20,508,436**	**26,001,592**	**28,617,482**

	TIMP difference					
	2015	2016	2017	2018	2019	2020
Rate Base						
CWIP	-	-	-	-	-	-
Plant In-Service	6,975,275	(139,911)	(692,606)	(227,436)	157,562	(2,314,494)
Less Accumulated Book Depreciation Reserve	38,753	144,634	140,960	147,461	182,512	153,797
Less Accumulated Deferred Taxes	3,939,024	7,899,697	8,103,886	11,353,751	13,954,388	12,540,875
End Of Month Rate Base	**2,997,499**	**(8,184,243)**	**(8,937,453)**	**(11,728,649)**	**(13,979,339)**	**(15,009,166)**
	-	-	-	-	-	-
Return on Rate Base	-	-	-	-	-	-
Debt Return	(3,003)	(36,357)	(187,173)	(202,440)	(233,059)	(346,148)
Equity Return	(7,011)	(174,673)	(586,916)	(646,734)	(790,105)	(1,134,557)
Total Return on Rate Base	**(10,014)**	**(211,030)**	**(774,089)**	**(849,174)**	**(1,023,164)**	**(1,480,705)**
	-	-	-	-	-	-
Income Statement Items	-	-	-	-	-	-
AFUDC Pre-Eligible	-	-	-	-	-	-
Operating Expenses	258,300	177,148	(266,744)	(1,332)	(2,077)	3,614
Property Taxes	-	128,567	(2,579)	(12,766)	(4,192)	2,904
Book Depreciation	38,753	105,881	(3,674)	6,500	35,051	(28,715)
Deferred Taxes	3,939,022	3,960,674	204,189	3,249,865	2,600,637	(1,413,513)
Gross Up for Income Tax	(4,037,202)	(4,177,436)	(623,164)	(3,783,248)	(3,219,796)	646,457
Carryover	-	-	-	-	-	-
Total Income Statement Expense	**198,873**	**194,834**	**(691,972)**	**(540,981)**	**(590,378)**	**(789,252)**
	-	**-**	**-**	**-**	**-**	**-**
Revenue Requirement	-	-	-	-	-	-
Total	**188,859**	**(16,197)**	**(1,466,060)**	**(1,390,155)**	**(1,613,541)**	**(2,269,957)**

	DIMP difference					
	2015	2016	2017	2018	2019	2020
Rate Base						
CWIP	-	-	-	-	-	-
Plant In-Service	284,369	2,348,056	2,882,220	2,449,627	2,291,535	1,254,666
Less Accumulated Book Depreciation Reserve	(7,553)	21,479	71,015	132,089	182,668	226,903
Less Accumulated Deferred Taxes	1,857,637	3,780,068	6,927,249	8,899,788	10,020,761	9,018,178
End Of Month Rate Base	**(1,565,714)**	**(1,453,492)**	**(4,116,043)**	**(6,582,250)**	**(7,911,894)**	**(7,990,415)**
	-	-	-	-	-	-
Return on Rate Base	-	-	-	-	-	-
Debt Return	(25,632)	(45,016)	(64,849)	(116,449)	(163,099)	(172,466)
Equity Return	(59,846)	(136,294)	(226,521)	(389,078)	(536,464)	(597,927)
Total Return on Rate Base	**(85,479)**	**(181,310)**	**(291,369)**	**(505,528)**	**(699,563)**	**(770,393)**
	-	-	-	-	-	-
Income Statement Items	-	-	-	-	-	-
AFUDC Pre-Eligible	-	-	-	-	-	-
Operating Expenses	(126,721)	(200,000)	299,530	(470)	30	30
Property Taxes	-	5,241	43,279	53,125	45,151	42,237
Book Depreciation	(71,783)	(52,825)	128,104	139,643	129,147	187,034
Deferred Taxes	1,857,637	1,922,431	3,147,181	1,972,539	1,120,973	(1,002,583)
Gross Up for Income Tax	(1,943,901)	(2,064,174)	(3,381,622)	(2,293,838)	(1,526,081)	604,445
Carryover	-	-	-	-	-	-
Total Income Statement Expense	**(284,768)**	**(389,327)**	**236,472**	**(129,001)**	**(230,780)**	**(168,837)**
	-	**-**	**-**	**-**	**-**	**-**
Revenue Requirement	-	-	-	-	-	-
Total	**(370,247)**	**(570,636)**	**(54,897)**	**(634,529)**	**(930,343)**	**(939,230)**

	Base Rate Credit, ADIT Prorate, Carryover difference					
	2015	2016	2017	2018	2019	2020
Rate Base						
CWIP	-	-	-	-	-	-
Plant In-Service	-	-	-	-	-	-
Less Accumulated Book Depreciation Reserve	-	-	-	-	-	-
Less Accumulated Deferred Taxes	-	-	-	-	-	-
End Of Month Rate Base	**-**	**-**	**-**	**-**	**-**	**-**
	-	-	-	-	-	-
Return on Rate Base	-	-	-	-	-	-
Debt Return	-	-	-	-	-	-
Equity Return	-	-	-	-	-	-
Total Return on Rate Base	**-**	**-**	**-**	**-**	**-**	**-**
	-	-	-	-	-	-
Income Statement Items	-	-	-	-	-	-
AFUDC Pre-Eligible	-	-	-	-	-	-
Operating Expenses	-	-	-	-	-	-
Property Taxes	-	-	-	-	-	-
Book Depreciation	-	-	-	-	-	-
Deferred Taxes	-	134,029	108,767	156,574	153,016	55,916
Gross Up for Income Tax	-	-	-	-	-	-
Carryover	-	1,935,343	(1,184,983)	261,276	-	-
Total Income Statement Expense	**-**	**2,069,372**	**(1,076,216)**	**417,850**	**153,016**	**55,916**
	-	**-**	**-**	**-**	**-**	**-**
Revenue Requirement	-	-	-	-	-	-
Total	**-**	**2,069,372**	**(1,076,216)**	**417,850**	**153,016**	**55,916**

	TOTAL difference					
	2015	2016	2017	2018	2019	2020
Rate Base						
CWIP	-	-	-	-	-	-
Plant In-Service	7,259,645	2,208,144	2,189,614	2,222,190	2,449,096	(1,059,828)
Less Accumulated Book Depreciation Reserve	31,200	166,114	211,976	279,550	365,180	380,700
Less Accumulated Deferred Taxes	5,796,660	11,679,766	15,031,135	20,253,539	23,975,149	21,559,053
End Of Month Rate Base	**1,431,784**	**(9,637,735)**	**(13,053,497)**	**(18,310,899)**	**(21,891,233)**	**(22,999,581)**
	-	-	-	-	-	-
Return on Rate Base	-	-	-	-	-	-
Debt Return	(28,635)	(81,373)	(252,022)	(318,890)	(396,158)	(518,614)
Equity Return	(66,857)	(310,967)	(813,436)	(1,035,812)	(1,326,569)	(1,732,484)
Total Return on Rate Base	**(95,493)**	**(392,340)**	**(1,065,458)**	**(1,354,702)**	**(1,722,727)**	**(2,251,098)**
	-	-	-	-	-	-
Income Statement Items	-	-	-	-	-	-
AFUDC Pre-Eligible	-	-	-	-	-	-
Operating Expenses	131,579	(22,852)	32,786	(1,802)	(2,047)	3,644
Property Taxes	-	133,809	40,700	40,359	40,959	45,141
Book Depreciation	(33,030)	53,056	124,430	146,143	164,198	158,319
Deferred Taxes	5,796,658	6,017,134	3,460,137	5,378,978	3,874,626	(2,360,179)
Gross Up for Income Tax	(5,981,103)	(6,241,611)	(4,004,785)	(6,077,086)	(4,745,878)	1,250,902
Carryover	-	1,935,343	(1,184,983)	261,276	-	-
Total Income Statement Expense	**(85,896)**	**1,874,879**	**(1,531,715)**	**(252,132)**	**(668,142)**	**(902,173)**
	-	**-**	**-**	**-**	**-**	**-**
Revenue Requirement	-	-	-	-	-	-
Total	**(181,388)**	**1,482,539**	**(2,597,173)**	**(1,606,834)**	**(2,390,869)**	**(3,153,270)**

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☒ **Public Document – Not Public (Or Privileged) Data Has Been Excised**
☐ **Public Document**

Xcel Energy
Docket No.: G002/M-16-891
Response To: Department of Commerce Informal Information Request No. 2
Requestor: Adam J. Heinen
Date Received: January 20, 2017

Question:

Subject: Pipeline Data Project - Petition Attachment D

A. Please reconcile the difference between the software capital expenditures of $2,073,169 shown on Attachment D of the Petition, and the contracted amount on page 4 of the Company's Trade Secret response to the Office of the Attorney General's Information Request No. 9.1, Attachment B, submitted in Docket No. G002/M-15-808. Please provide supporting documentation, including invoices and any change orders required for costs above the contracted amount.

B. Please provide the vendor contracts and highlight the distinction between Minnesota and the Company's other Operating Companies for work related to the Pipeline Data Project – Distribution GIS Data Entry 2015.

Response:

A. Table 1 below shows the reconciliation of the Minnesota Pipeline Data Project (MN PDP) Costs included in the GUIC. Trade Secret Attachment A provides a summary and accounting system detail of inception to date charges related to the MN PDP. Attachment A is provided in live Excel spreadsheet format.

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Table 1: Reconciliation of
Minnesota Pipeline Data Project Costs

[TRADE SECRET BEGINS…

	2015 MN PDP - Cyient Contract Charges
	2016 MN PDP - Cyient Contract Charges
	Total Charged to Cyient Contract*
	2015 MN QA/QC Consulting and Outside
	2015 MN QA/QC Contract Labor
	2016 MN QA/QC Contract Labor
	Total QA/QC
	Consulting Professional Services Ot
	Misc

…TRADE SECRET ENDS]

$49,945	Non-GUIC Charges
$2,073,169	Total Pipeline Data Project Capital in GUIC

*an additional $5,766 was invoiced under the Cyient contract but was not charged to the GUIC work order.

The Company has confirmed that the total vendor contracted charges did not surpass the contract amount of **[TRADE SECRET BEGINS TRADE SECRET ENDS]** and therefore no change orders were necessary. The Minnesota specific invoices are provided as Trade Secret Attachment B. A total of **[TRADE SECRET BEGINS TRADE SECRET ENDS]** was invoiced in 2015 and **[TRADE SECRET BEGINS TRADE SECRET ENDS]** was invoiced in 2016 (see Attachment A "Invoice Detail" tab. A total of $5,766 was invoiced in 2015 but was not charged to the GUIC work order, and the Company is not requesting recovery of these dollars.

After performing additional research, the Company has discovered that a total of $49,944.50 of non-GUIC costs was inadvertently charged to the MN PDP work order. Please reference Attachment A (see "2015 Detail Outside Vendors" tab, charges highlighted in red). The non-GUIC invoices inadvertently charged to the MN PDP work order are provided as Trade Secret Attachment C. The Company acknowledges these charges should be removed from our GUIC recovery request.

In addition to the contract vendor costs, the Company also incurred charges for quality assurance/quality control (QA/QC) work on this project. The charges totaled **[TRADE SECRET BEGINS TRADE SECRET**

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ENDS] in 2015 as shown on Attachment A ("MN PDP Summary 15-16" tab, see charges CWIP Consulting and Outside & CWIP Contract Labor) and **[TRADE SECRET BEGINS TRADE SECRET ENDS]** in 2016 (see "2016 Detail Summary" on Attachment A – "IQN" charges). These charges were not included in original filed amounts. The QA/QC work was necessary in order to facilitate and validate data integrity with the vendor. The group maintains a problem-action-resolution system related to data acceptance testing and tracks and assists the vendor with questions throughout the project. This ensures the vendor captures all of the information and validates that records created are based on source data.

In 2016, contract labor of $500 was incurred (see "2016 Detail Summary" on Attachment A - ACME $ OF ORMOND BEACH). These are incremental charges related to consulting fees from a contract consultant resource that worked with the Company to gain Capital Asset Accounting approval for the capitalization of this work.

The remaining charges relate to invoice processing fees, purchasing overheads, and other miscellaneous administrative charges incurred to execute the contract with the vendor to achieve program goals.

B. Please see Trade Secret Attachment D and Trade Secret Attachment E for the respective Colorado ("PSCO") and Minnesota contracts for work related to the Pipeline Data Project - Distribution GIS Data Entry 2015.

The Company executed a contract with this vendor effective July 15, 2014 for the Public Service of Colorado (PSCo) PDP. Because other jurisdictions may have similar PDP project needs, all operating companies were added to the second contract, although the scope of work was only associated with the MN PDP project. This contractual arrangement is beneficial since any additional scope of work ($ value only) could be added to the contract without the need for another Request for Proposal (RFP). Any PDP project added to the existing contract would have its own unique work order created to ensure invoices are only billed to the respective operating company for which the work was performed. An approval process governs any amounts added to contract. This process also expedites the contract arrangement timeline and avoids potentially extended contractual delays. The charges are managed through the invoicing process. Each operating company had its own designated work order to ensure MN work was charged to the MN work order and PSCO work was charged to the PSCO work order.

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Attachments A, B, C, D and E are marked as "Not-Public" because they include information considered to be trade secret data as defined by Minn. Stat. § 13.37(1)(b). This data includes confidential contract terms and vendor invoicing information. 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, B, C, D and E are marked as "Not-Public" in their entirety. Also, vendor banking information has been redacted from Attachments B and C as confidential. 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 spreadsheet providing summary and accounting system detail of charges related to the MN PDP. Attachment B is copies of Cyient Inc.'s Minnesota-specific invoices to the Company for services charged to the GUIC work order. Attachment C is copies of Cyient Inc.'s non-GUIC invoices inadvertently charged to the MN PDP work order. Attachments D and E are the Colorado and Minnesota contracts, respectively, detailing terms for work related to the Pipeline Data Project.
2. **Authors:** Attachment A was created by Geospatial Tech Data and Gas System Strategy personnel of Northern States Power Company-Minnesota. The Attachment B and C invoices were generated by Cyient, Inc. The Attachment D and E contracts were drafted by Public Service Company of Colorado legal personnel.
3. **Importance:** We protect contract terms and vendor invoicing information, as disclosure can adversely affect negotiations and increase costs for services. Vendor banking information is also protected as confidential.
4. **Date the Information was Prepared:** The Attachment A spreadsheet was created January 2017. The Attachment B invoices were generated throughout the second half of 2015. The Attachment C invoices were generated in December 2015. The Attachment D contract was executed July 15, 2014. The Attachment E contract was executed March 31, 2015.

Preparer:	Darius Elder
Title:	Manager
Department:	Geospatial Tech Data XS
Telephone:	303-571-3980
Date:	February 8, 2017

PUBLIC DOCUMENTS
NOT-PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company

Docket No. G002/M-16-891
DOC Informal Information Request No. 2
Attachment A - 5 Tabs (Live Spreadsheet)
Attachment B - Pages 1-14
Attachment C - Pages 1-2
Attachment D - Pages 1-61
Attachment E - Pages 1-61

Attachments A, B, C, D and E are marked as "Not-Public" because they include information considered to be trade secret data as defined by Minn. Stat. § 13.37(1)(b). This data includes confidential contract terms and vendor invoicing information. 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.

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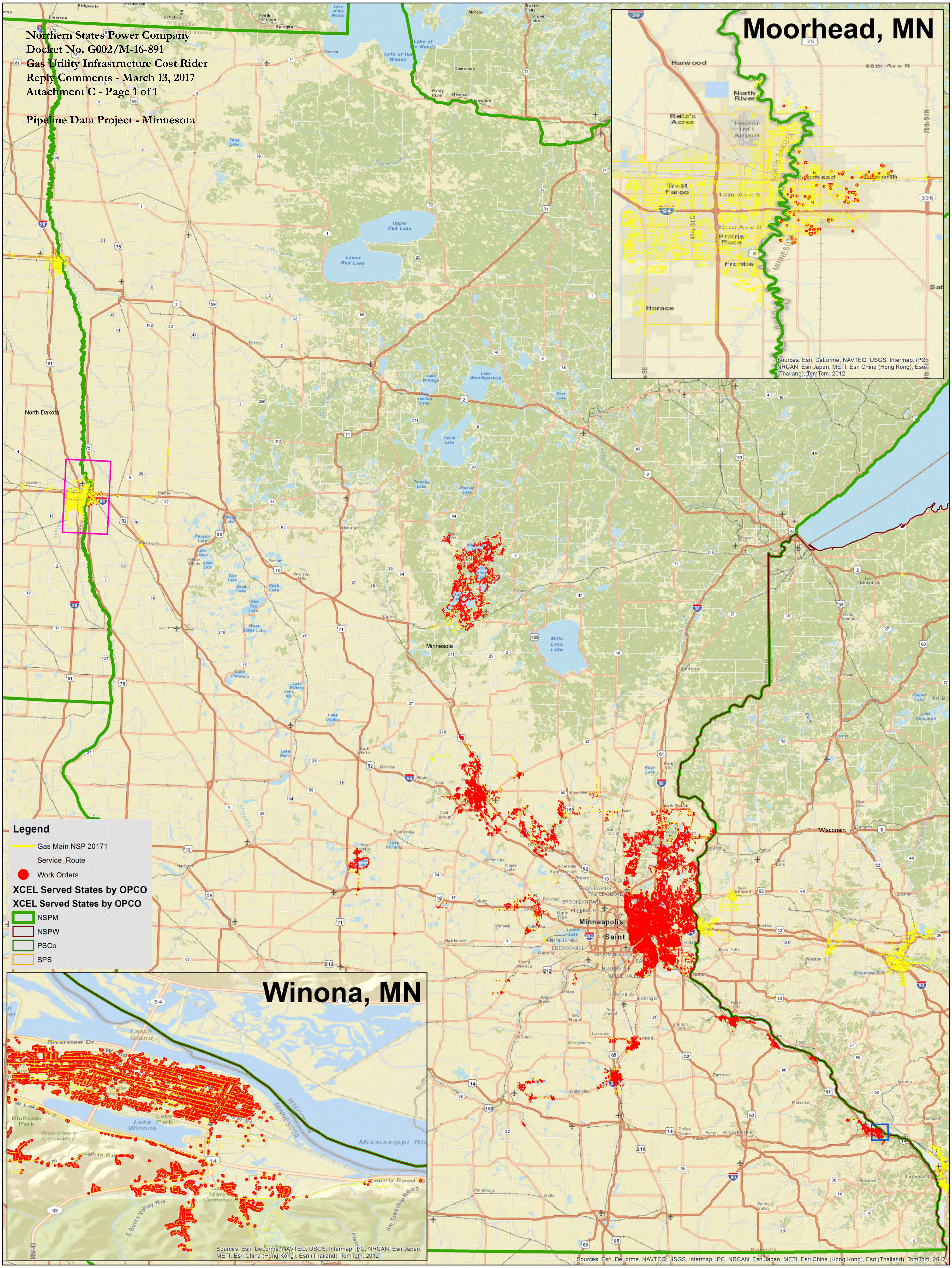
Northern States Power Company
Docket No. G002/M-16-891
Gas Utility Infrastructure Cost Rider
Reply Comments - March 13, 2017
Attachment C - Page 1 of 1

Pipeline Data Project - Minnesota



MN GUIC Rider - Annual Tracker Summary

	As filed			Revised			Difference		
	2015	**2016**	**2017**	**2015**	**2016**	**2017**	**2015**	**2016**	**2017**
	Actual	**Forecast**	**Forecast**	**Actual**	**Forecast**	**Forecast**	**Actual**	**Forecast**	**Forecast**
Incremental Gas Utility Projects:									
Operations & Maintenance Expenses									
TIMP	1,278,010	177,148	1,146,990	1,278,010	177,148	1,146,990	-	-	-
DIMP	3,542,056	4,437,500	4,551,000	3,542,056	4,437,500	4,551,000	-	-	-
Gas O&M - Total	4,820,067	4,614,648	5,697,990	4,820,067	4,614,648	5,697,990	-	-	-
Capital-Related Revenue Requirements									
TIMP	3,283,015	5,934,188	7,858,658	3,283,015	5,934,188	7,858,658	-	-	-
DIMP	325,743	2,235,461	4,138,079	325,743	2,225,429	4,120,944	-	(10,032)	(17,136)
Gas Utility Projects - Capital RR Total	3,608,758	8,169,649	11,996,737	3,608,758	8,159,617	11,979,602	-	(10,032)	(17,136)
Deferred Gas Infrastructure Costs									
TIMP	820,227	820,227	820,227	820,227	820,227	820,227	-	-	-
DIMP	3,733,856	3,733,856	3,733,856	3,733,856	3,733,856	3,733,856	-	-	-
Gas Deferral Costs - Total	4,554,083	4,554,083	4,554,083	4,554,083	4,554,083	4,554,083	-	-	-
ADIT Prorate	-	134,029	108,767	-	134,062	108,811	-	33	44
Revenue Requirement in Base Rates	(480,000)	(480,000)	(480,000)	(480,000)	(480,000)	(480,000)	-	-	-
GUIC True-up Carryover	-	(1,184,983)	261,276	-	(1,184,983)	251,278	-	-	(9,999)
Revenue Requirement (RR)	**12,502,907**	**15,807,425**	**22,138,854**	**12,502,907**	**15,797,427**	**22,111,764**	**-**	**(9,999)**	**(27,090)**
Revenue Collections (RC)	13,687,890	12,851,194	14,726,147	13,687,890	12,851,194	14,711,399	-	-	(14,748)
Collection Jan-March Current Impact		2,694,955	10,107,662		2,694,955	10,095,320	-	-	(12,342)
Collection Jan-March Future Impact			(2,694,955)			(2,694,955)	-	-	-
Balance	(1,184,983)	261,276	-	(1,184,983)	251,278	-	-	(9,999)	-

2015 Tracker														
	Carryover	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Nov-15**	**Dec-15**	**Annual Total**
		Actual	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	
Incremental Gas Utility Projects:														
Operations & Maintenance Expenses														
TIMP		778	1,782	-	79,556	267,747	227,227	13,450	3,812	133,817	165,876	257,219	126,746	1,278,010
DIMP		-	-	2,840	40,622	196,822	258,078	723,597	403,145	576,081	700,201	495,759	144,910	3,542,056
Gas O&M - Total		778	1,782	2,840	120,178	464,569	485,304	737,048	406,957	709,898	866,077	752,978	271,656	4,820,067
Capital-Related Revenue Requirements														
TIMP		245,916	244,062	241,947	238,765	235,649	234,052	231,818	229,924	228,240	320,943	415,529	416,169	3,283,015
DIMP		10,002	9,938	9,718	9,690	10,048	10,710	11,898	17,422	30,730	47,921	67,082	90,584	325,743
Gas Utility Projects - Capital RR Total		255,918	254,000	251,665	248,455	245,697	244,762	243,717	247,347	258,970	368,864	482,612	506,753	3,608,758
Deferred Gas Infrastructure Costs														
TIMP		68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	820,227
DIMP		311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	3,733,856
Gas Deferral Costs - Total		379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	4,554,083
Revenue Requirement in Base Rates		-	(270)	(267)	(12,219)	(46,850)	(48,208)	(69,327)	(38,264)	(66,149)	(66,149)	(66,149)	(66,147)	(480,000)
GUIC True-up Carryover	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Revenue Requirement (RR)		**636,203**	**635,018**	**633,745**	**735,922**	**1,042,923**	**1,061,365**	**1,290,944**	**995,547**	**1,282,226**	**1,548,299**	**1,548,947**	**1,091,768**	**12,502,907**
Revenue Collections (RC)		-	3,302,286	2,090,668	1,141,464	603,108	409,426	411,212	413,083	485,384	880,893	1,602,079	2,348,288	13,687,890
Monthly RR - RC		636,203	(2,667,268)	(1,456,923)	(405,543)	439,815	651,939	879,732	582,464	796,842	667,406	(53,131)	(1,256,520)	
Balance (RR - RC)		636,203	(2,031,065)	(3,487,988)	(3,893,530)	(3,453,715)	(2,801,776)	(1,922,044)	(1,339,580)	(542,738)	124,668	71,537	(1,184,983)	

2016 Tracker

	Carryover	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Annual Total
		Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Forecast	Forecast	Forecast	Forecast	
Incremental Gas Utility Projects:														
Operations & Maintenance Expenses														
TIMP		7,935	11,808	8,734	1,829	3,136	1,414	131	423	35,435	70,870	17,717	17,717	177,148
DIMP		(8,361)	24,614	7,973	19,764	351,428	237,412	658,004	640,296	626,599	516,306	681,745	681,720	4,437,500
Gas O&M - Total		(426)	36,422	16,707	21,593	354,564	238,826	658,135	640,718	662,034	587,176	699,462	699,437	4,614,648
Capital-Related Revenue Requirements														
TIMP		442,273	438,996	436,521	433,536	430,599	466,904	495,181	512,784	551,178	565,691	570,125	590,400	5,934,188
DIMP		129,715	129,876	128,136	127,216	155,665	183,536	181,681	183,752	217,919	254,990	263,626	269,316	2,225,429
Gas Utility Projects - Capital RR Total		571,988	568,872	564,657	560,752	586,265	650,440	676,862	696,536	769,097	820,681	833,752	859,717	8,159,617
Deferred Gas Infrastructure Costs:														
TIMP		68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	820,227
DIMP		311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	3,733,856
Gas Deferral Costs - Total		379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	4,554,083
ADIT Prorate		11,172	11,172	11,172	11,172	11,172	11,172	11,172	11,172	11,172	11,172	11,172	11,172	134,062
Revenue Requirement in Base Rates		-	(270)	(267)	(12,219)	(46,850)	(48,208)	(69,327)	(38,264)	(66,149)	(66,149)	(66,149)	(66,147)	(480,000)
2015 GUIC True-up Carryover	(1,184,983)	-	-	-	-	-	-	-	-	(296,246)	(296,246)	(296,246)	(296,246)	(1,184,983)
Revenue Requirement (RR)		**962,241**	**995,702**	**971,776**	**960,804**	**1,284,658**	**1,231,737**	**1,656,349**	**1,689,669**	**1,459,415**	**1,436,140**	**1,561,498**	**1,587,439**	**15,797,427**
Revenue Collections (RC)		3,163,660	2,642,628	1,844,781	1,221,378	606,284	431,894	422,173	445,843	168,733	339,298	620,485	944,036	12,851,194
Monthly RR - RC		(2,201,419)	(1,646,926)	(873,006)	(260,574)	678,374	799,843	1,234,176	1,243,826	1,290,682	1,096,842	941,013	643,403	
Collection Jan-Aug		-	-	-	-	-	-	-	-	(256,427)	(256,427)	(256,427)	(256,427)	
Balance (RR - RC)		(2,201,419)	(3,848,345)	(4,721,350)	(4,981,925)	(4,303,551)	(3,503,708)	(2,269,532)	(1,025,707)	1,034,255	1,874,671	2,559,257	2,946,233	

Recovery Timing	
2016 Revenue Requirement	15,797,427
Jan-Dec 2016 Recovery	12,851,194
Jan-March 2017 Recovery	2,694,955
Total Recovery	15,546,149
Difference	251,278

2017 Tracker

	Carryover	Jan-17 Forecast	Feb-17 Forecast	Mar-17 Forecast	Apr-17 Forecast	May-17 Forecast	Jun-17 Forecast	Jul-17 Forecast	Aug-17 Forecast	Sep-17 Forecast	Oct-17 Forecast	Nov-17 Forecast	Dec-17 Forecast	Annual Total Forecast
Incremental Gas Utility Projects:														
Operations & Maintenance Expenses														
TIMP		-	882	882	29,998	115,581	118,228	169,402	93,524	167,637	204,694	180,872	65,290	1,146,990
DIMP		1,000	1,000	2,000	118,000	458,000	470,000	672,000	375,000	664,000	810,000	717,000	263,000	4,551,000
Gas O&M - Total		1,000	1,882	2,882	147,998	573,581	588,228	841,402	468,524	831,637	1,014,694	897,872	328,290	5,697,990
Capital-Related Revenue Requirements														
TIMP		649,149	649,647	649,007	648,253	648,289	649,374	651,481	654,573	658,519	662,893	667,112	670,362	7,858,658
DIMP		290,257	289,654	288,968	292,053	301,771	316,200	334,344	356,141	380,585	404,781	425,859	440,330	4,120,944
Gas Utility Projects - Capital RR Total		939,405	939,300	937,975	940,306	950,061	965,574	985,825	1,010,714	1,039,104	1,067,674	1,092,971	1,110,692	11,979,602
Deferred Gas Infrastructure Costs														
TIMP		68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	68,352	820,227
DIMP		311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	311,155	3,733,856
Gas Deferral Costs - Total		379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	379,507	4,554,083
ADIT Prorate		9,068	9,068	9,068	9,068	9,068	9,068	9,068	9,068	9,068	9,068	9,068	9,068	108,811
Revenue Requirement in Base Rates		(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(480,000)
GUIC True-up Carryover	251,278	-	-	-	27,920	27,920	27,920	27,920	27,920	27,920	27,920	27,920	27,920	251,278
Revenue Requirement (RR)		**1,288,980**	**1,289,757**	**1,289,432**	**1,464,799**	**1,900,136**	**1,930,297**	**2,203,721**	**1,855,732**	**2,247,235**	**2,458,862**	**2,367,337**	**1,815,476**	**22,111,764**
Revenue Collections (RC)		1,060,372	893,057	741,527	1,571,787	986,125	605,020	571,305	544,795	633,109	1,233,426	2,323,296	3,547,580	14,711,399
Monthly RR - RC		228,608	396,701	547,905	(106,988)	914,011	1,325,277	1,632,416	1,310,937	1,614,126	1,225,435	44,041	(1,732,104)	
Collection Jan-March		-	-	-	429,797	429,797	429,797	429,797	429,797	429,797	429,797	429,797	429,797	
Balance (RR - RC)		2,923,563	3,320,264	3,868,169	322,808	1,666,616	3,421,689	5,483,902	7,224,635	9,268,558	10,923,790	11,397,628	10,095,320	

Recovery Timing	
2017 Revenue Requirement	22,111,764
Apr-Dec 2017 Recovery	12,016,443
Jan-March 2018 Recovery	10,095,125
Total Recovery	22,111,568
Difference	196

DIMP
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DIMP Transmission, Distribution & Software	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Total
Rate Base													
Plant In-Service	1,102,697	1,128,280	1,173,169	1,240,769	1,368,116	1,505,931	1,750,532	2,768,217	4,627,668	6,571,349	9,018,156	12,064,627	12,064,627
Less Accumulated Book Depreciation Reserve	31,851	34,196	36,615	39,152	41,894	44,914	48,337	53,086	60,859	72,629	89,014	111,172	111,172
Less Accumulated Deferred Taxes	268,549	327,077	387,451	450,760	519,143	594,363	679,326	796,368	987,750	1,278,769	1,684,769	2,236,825	2,236,825
End Of Month Rate Base	**802,297**	**767,006**	**749,103**	**750,857**	**807,079**	**866,653**	**1,022,870**	**1,918,763**	**3,579,059**	**5,219,951**	**7,244,373**	**9,716,630**	**9,716,630**
Return on Rate Base													
Debt Return	1,506	1,484	1,434	1,419	1,474	1,583	1,787	2,782	5,200	8,322	11,789	16,042	54,823
Equity Return	3,516	3,466	3,348	3,312	3,440	3,696	4,173	6,496	12,141	19,431	27,525	37,456	128,001
Total Return on Rate Base	**5,022**	**4,950**	**4,782**	**4,731**	**4,914**	**5,279**	**5,960**	**9,278**	**17,341**	**27,754**	**39,315**	**53,498**	**182,824**
Income Statement Items													
Property Taxes	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585	19,025
Book Depreciation	2,238	2,345	2,419	2,537	2,742	3,021	3,423	4,749	7,773	11,770	16,385	22,158	81,558
Deferred Taxes	55,856	58,529	60,373	63,309	68,383	75,220	84,962	117,042	191,382	291,018	406,000	552,056	2,024,132
Gross Up for Income Tax	(54,699)	(57,471)	(59,442)	(62,472)	(67,577)	(74,395)	(84,032)	(115,233)	(187,352)	(284,206)	(396,202)	(538,714)	(1,981,796)
Total Income Statement Expense	**4,980**	**4,988**	**4,936**	**4,959**	**5,134**	**5,431**	**5,938**	**8,144**	**13,389**	**20,168**	**27,768**	**37,086**	**142,919**
Revenue Requirement													
Total	**10,002**	**9,938**	**9,718**	**9,690**	**10,048**	**10,710**	**11,898**	**17,422**	**30,730**	**47,921**	**67,082**	**90,584**	**325,743**

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DIMP Transmission, Distribution & Software	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													
Plant In-Service	12,448,476	12,404,073	12,439,892	12,545,396	15,108,073	15,105,609	15,067,244	15,787,084	21,714,956	23,060,776	23,811,292	24,638,950	24,638,950
Less Accumulated Book Depreciation Reserve	136,935	163,055	189,166	215,426	242,296	269,663	296,987	325,027	360,053	402,725	447,599	494,133	494,133
Less Accumulated Deferred Taxes	2,395,017	2,555,502	2,715,874	2,876,820	3,036,703	3,194,852	3,350,991	3,509,653	3,713,793	3,967,572	4,234,990	4,512,745	4,512,745
End Of Month Rate Base	**9,916,523**	**9,685,515**	**9,534,852**	**9,453,151**	**11,829,074**	**11,641,095**	**11,419,266**	**11,952,404**	**17,641,110**	**18,690,479**	**19,128,702**	**19,632,071**	**19,632,071**
Return on Rate Base													
Debt Return	18,570	18,540	18,179	17,959	20,129	22,199	21,811	22,106	27,991	34,364	35,771	36,661	294,280
Equity Return	41,393	41,328	40,523	40,033	44,870	49,483	48,619	49,275	62,393	76,599	79,735	81,721	655,972
Total Return on Rate Base	**59,963**	**59,868**	**58,702**	**57,993**	**64,999**	**71,682**	**70,430**	**71,381**	**90,384**	**110,963**	**115,506**	**118,382**	**950,252**
Income Statement Items													
Property Taxes	18,531	18,531	18,531	18,531	18,531	18,531	18,531	18,531	18,531	18,531	18,531	18,531	222,374
Book Depreciation	25,763	26,120	26,111	26,260	44,264	62,157	62,115	62,831	69,818	77,463	79,666	81,325	643,893
Deferred Taxes	158,193	160,485	160,371	160,946	159,884	158,148	156,140	158,661	204,141	253,779	267,418	277,756	2,275,921
Gross Up for Income Tax	(132,735)	(135,128)	(135,579)	(136,513)	(132,013)	(126,982)	(125,535)	(127,653)	(164,955)	(205,745)	(217,495)	(226,677)	(1,867,010)
Total Income Statement Expense	**69,752**	**70,008**	**69,434**	**69,223**	**90,666**	**111,855**	**111,251**	**112,371**	**127,535**	**144,027**	**148,120**	**150,935**	**1,275,177**
Revenue Requirement													
Total	**129,715**	**129,876**	**128,136**	**127,216**	**155,665**	**183,536**	**181,681**	**183,752**	**217,919**	**254,990**	**263,626**	**269,316**	**2,225,429**

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DIMP **Transmission, Distribution & Software**	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													
Plant In-Service	24,834,662	25,022,983	25,207,650	26,099,781	27,529,656	29,323,686	31,480,351	33,997,470	36,699,059	39,229,288	41,410,404	42,766,505	42,766,505
Less Accumulated Book Depreciation Reserve	541,742	589,754	638,159	687,695	739,671	795,036	854,554	918,983	988,897	1,064,310	1,144,674	1,228,756	1,228,756
Less Accumulated Deferred Taxes	4,762,121	5,013,683	5,267,368	5,526,902	5,799,387	6,090,012	6,402,900	6,742,125	7,110,889	7,509,369	7,934,715	8,380,508	8,380,508
End Of Month Rate Base	**19,530,799**	**19,419,546**	**19,302,124**	**19,885,184**	**20,990,598**	**22,438,637**	**24,222,898**	**26,336,362**	**28,599,272**	**30,655,609**	**32,331,015**	**33,157,240**	**33,157,240**
Return on Rate Base													
Debt Return	37,042	36,841	36,624	37,065	38,662	41,077	44,134	47,821	51,960	56,045	59,575	61,941	548,785
Equity Return	81,426	80,984	80,509	81,477	84,988	90,297	97,017	105,121	114,220	123,201	130,960	136,161	1,206,360
Total Return on Rate Base	**118,468**	**117,825**	**117,133**	**118,542**	**123,649**	**131,373**	**141,151**	**152,942**	**166,180**	**179,246**	**190,535**	**198,102**	**1,755,146**
Income Statement Items													
Property Taxes	37,845	37,845	37,845	37,845	37,845	37,845	37,845	37,845	37,845	37,845	37,845	37,845	454,142
Book Depreciation	82,400	82,804	83,196	84,328	86,768	90,156	94,309	99,221	104,706	110,204	115,156	118,873	1,152,120
Deferred Taxes	249,375	251,562	253,685	259,535	272,484	290,626	312,888	339,225	368,764	398,480	425,345	445,794	3,867,763
Gross Up for Income Tax	(197,831)	(200,382)	(202,891)	(208,196)	(218,976)	(233,801)	(251,848)	(273,092)	(296,910)	(320,994)	(343,022)	(360,285)	(3,108,227)
Total Income Statement Expense	**171,789**	**171,829**	**171,835**	**173,512**	**178,122**	**184,827**	**193,193**	**203,199**	**214,404**	**225,535**	**235,325**	**242,228**	**2,365,798**
Revenue Requirement													
Total	**290,257**	**289,654**	**288,968**	**292,053**	**301,771**	**316,200**	**334,344**	**356,141**	**380,585**	**404,781**	**425,859**	**440,330**	**4,120,944**

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DIMP **Transmission, Distribution & Software**	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													
Plant In-Service	43,045,335	43,381,401	43,717,475	44,369,683	45,869,830	47,782,473	49,537,206	52,498,143	54,741,252	57,185,197	58,987,499	59,525,198	59,525,198
Less Accumulated Book Depreciation Reserve	1,314,557	1,401,003	1,488,156	1,576,348	1,666,802	1,760,843	1,858,738	1,961,589	2,069,910	2,183,156	2,300,866	2,421,035	2,421,035
Less Accumulated Deferred Taxes	8,603,229	8,827,669	9,054,011	9,283,041	9,517,873	9,762,225	10,016,996	10,284,696	10,567,359	10,863,205	11,171,280	11,486,398	11,486,398
End Of Month Rate Base	**33,127,550**	**33,152,729**	**33,175,307**	**33,510,295**	**34,685,155**	**36,259,406**	**37,661,472**	**40,251,858**	**42,103,983**	**44,138,836**	**45,515,353**	**45,617,765**	**45,617,765**
Return on Rate Base													
Debt Return	62,694	62,690	62,735	63,073	64,502	67,102	69,917	73,693	77,895	81,571	84,798	86,197	856,867
Equity Return	137,817	137,808	137,907	138,650	141,790	147,506	153,694	161,995	171,232	179,313	186,406	189,481	1,883,598
Total Return on Rate Base	**200,511**	**200,498**	**200,642**	**201,724**	**206,291**	**214,607**	**223,611**	**235,688**	**249,126**	**260,885**	**271,204**	**275,678**	**2,740,465**
Income Statement Items													
Property Taxes	65,689	65,689	65,689	65,689	65,689	65,689	65,689	65,689	65,689	65,689	65,689	65,689	788,267
Book Depreciation	120,592	121,238	121,944	122,983	125,245	128,832	132,686	137,643	143,112	148,038	152,501	154,960	1,609,775
Deferred Taxes	222,720	224,440	226,343	229,029	234,833	244,351	254,771	267,700	282,663	295,846	308,075	315,118	3,105,889
Gross Up for Income Tax	(130,755)	(132,521)	(134,400)	(136,625)	(140,351)	(146,062)	(152,362)	(159,741)	(168,540)	(176,334)	(183,847)	(188,888)	(1,850,426)
Total Income Statement Expense	**278,246**	**278,845**	**279,577**	**281,076**	**285,416**	**292,810**	**300,784**	**311,291**	**322,923**	**333,240**	**342,417**	**346,879**	**3,653,506**
Revenue Requirement **Total**	**478,758**	**479,343**	**480,219**	**482,800**	**491,707**	**507,418**	**524,395**	**546,979**	**572,050**	**594,124**	**613,621**	**622,557**	**6,393,971**

MN GUIC Rider - Annual Tracker Summary

	2015 Actual	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast	2021 Forecast
Incremental Gas Utility Projects:							
Operations & Maintenance Expenses							
TIMP	1,278,010	177,148	1,146,990	1,003,135	1,492,870	1,495,074	1,496,706
DIMP	3,542,056	4,437,500	4,551,000	4,251,000	3,979,000	579,000	579,000
Gas O&M - Total	4,820,067	4,614,648	5,697,990	5,254,135	5,471,870	2,074,074	2,075,706
Capital-Related Revenue Requirements							
TIMP	3,283,015	5,934,188	7,858,658	8,905,091	12,365,366	16,334,302	20,124,550
DIMP	325,743	2,235,461	4,138,079	6,411,360	8,491,339	10,633,191	12,547,719
Gas Utility Projects - Capital RR Total	3,608,758	8,169,649	11,996,737	15,316,451	20,856,705	26,967,493	32,672,269
Deferred Gas Infrastructure Costs							
TIMP	820,227	820,227	820,227	820,227	820,227	-	-
DIMP	3,733,856	3,733,856	3,733,856	3,733,856	3,733,856	-	-
Gas Deferral Costs - Total	4,554,083	4,554,083	4,554,083	4,554,083	4,554,083	-	-
ADIT Prorate	-	134,029	108,767	156,574	153,016	55,916	82,211
Revenue Requirement in Base Rates	(480,000)	(480,000)	(480,000)	(480,000)	(480,000)	(480,000)	(480,000)
GUIC True-up Carryover	-	(1,184,983)	249,150	-	-	-	-
Revenue Requirement (RR)	**12,502,907**	**15,807,425**	**22,126,727**	**24,801,243**	**30,555,675**	**28,617,482**	**34,350,186**
Revenue Collections (RC)	13,687,890	12,811,102	14,525,502	23,684,138	28,091,135	29,529,694	31,717,752
Collection Jan-March Current Impact		2,747,174	10,348,399	11,465,504	13,930,044	13,017,833	15,650,267
Collection Jan-March Future Impact			(2,747,174)	(10,348,399)	(11,465,504)	(13,930,044)	(13,017,833)
Balance	(1,184,983)	249,150	-	-	-	-	-

Northern States Power Company

Department of Commerce Recommended Sales Forecast

Revenues	Jan-15 Actual	Feb-15 Actual	Mar-15 Actual	Apr-15 Actual	May-15 Actual	Jun-15 Actual	Jul-15 Actual	Aug-15 Actual	Sep-15 Actual	Oct-15 Actual	Nov-15 Actual	Dec-15 Actual
Monthly Inputs												
Revenue Requirement	636,203	635,018	633,745	735,922	1,042,923	1,061,365	1,290,944	995,547	1,282,226	1,548,299	1,548,947	1,091,768
Remaining true-up in current calendar year	0	0	0	0	0	0	0	0	0	0	0	0
Revenue Carried-forward balance	636,203	-2,031,065	-3,487,988	-3,893,530	-3,453,715	-2,801,776	-1,922,044	-1,339,580	-542,738	124,668	71,537	-1,184,983
Weighting												
Group Weighting (Revenue Apportionment Allocations - Docket No. G002/GR-09-1153)												
Residential	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67
Commercial Firm	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21
Commercial Demand Billed	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Interruptible	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Transport	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Allocated Revenue Requirements												
Residential	427,683.52	426,887.27	426,031.39	494,718.85	701,098.76	713,496.14	867,829.62	669,250.26	861,968.53	1,040,834.88	1,041,270.51	733,934.80
Commercial Firm	135,254.81	135,002.99	134,732.32	156,454.72	221,722.31	225,642.98	274,450.90	211,650.23	272,597.34	329,163.78	329,301.54	232,106.70
Commercial Demand Billed	13,366.62	13,341.74	13,314.99	15,461.71	21,911.81	22,299.28	27,122.74	20,916.43	26,939.56	32,529.77	32,543.38	22,938.06
Interruptible	35,958.82	35,891.87	35,819.91	41,595.02	58,947.05	59,989.40	72,965.47	56,269.29	72,472.68	87,511.42	87,548.05	61,707.85
Transport	23,939.04	23,894.47	23,846.56	27,691.26	39,243.11	39,937.04	48,575.66	37,460.43	48,247.59	58,259.40	58,283.79	41,081.06
Total	636,202.80	635,018.34	633,745.17	735,921.56	1,042,923.05	1,061,364.83	1,290,944.39	995,546.64	1,282,225.70	1,548,299.25	1,548,947.27	1,091,768.47
Sales by Customer Group (Billed by total Usage)												
Residential	69,329,287	59,695,740	45,753,721	25,845,215	11,164,131	7,009,553	6,608,509	6,694,477	8,791,180	20,055,698	40,206,278	59,123,398
Commercial Firm	37,201,235	32,273,605	26,445,582	13,039,826	7,876,474	3,950,082	4,053,841	4,421,990	5,148,287	10,543,900	21,125,735	32,225,244
Commercial Demand Billed	3,584,063	3,094,213	3,470,997	1,952,310	1,748,893	1,513,277	1,531,406	1,600,626	1,531,033	2,107,986	2,778,144	3,782,932
Interruptible	10,971,472	12,280,734	13,732,157	8,508,050	5,167,068	6,078,254	5,958,951	5,680,990	5,065,975	7,109,380	11,587,208	12,815,512
Transport	15,405,029	36,174,012	16,406,216	17,464,648	12,146,413	19,330,857	25,198,664	22,832,061	24,904,276	14,673,013	20,631,508	22,289,518
Total Therm Sales in Month	136,491,086	143,518,304	105,808,673	66,810,049	38,102,979	37,882,022	43,351,371	41,230,143	45,440,751	54,489,978	96,328,872	130,236,605
Flags												
Rate Change												
Rate Periods	0	0	0	0	0	0	0	0	0	0	0	0
Rate Period Calculations												
Revenue Requirement for Rate Period												
Remaining true-up in current calendar year												
Carried-Forward Balance from Previous Month (unless January)												
Revenue Needs During Remaining Rate Period												
Retail Dth Sales in Rate Period												
Cost Per therm												
Allocated Cost Per therm												
Residential												
Commercial Firm												
Commercial Demand Billed												
Interruptible												
Transport												
Revenues												
Residential												
Commercial Firm												
Commercial Demand Billed												
Interruptible												
Transport												
Forecast Revenues							0	0	0	0	0	0
Actual Revenues		3,302,286	2,090,668	1,141,464	603,108	409,426	411,212	413,083	485,384	880,893	1,602,079	2,348,288
Actual & Forecast Total	0	3,302,286	2,090,668	1,141,464	603,108	409,426	411,212	413,083	485,384	880,893	1,602,079	2,348,288
Annual Total												13,687,890

Northern States Power Company

Department of Commerce Recommended Sales Forecast

Revenues	Jan-16 Actual	Feb-16 Actual	Mar-16 Actual	Apr-16 Actual	May-16 Actual	Jun-16 Actual	Jul-16 Actual	Aug-16 Actual	Sep-16 Forecast	Oct-16 Forecast	Nov-16 Forecast	Dec-16 Forecast
Monthly Inputs												
Revenue Requirement	970,599	971,085	963,800	941,038	933,892	995,654	999,676	1,050,707	1,130,397	1,217,417	1,177,338	1,203,306
Remaining true-up in current calendar year	0	0	0	0	0	0	0	0	-296,246	-296,246	-296,246	-296,246
Revenue Carried-forward balance	-2,201,421	-3,848,350	-4,721,359	-4,981,936	-4,302,900	-3,501,728	-2,266,220	-1,021,061	1,036,752	1,890,988	2,593,880	2,996,323
Weighting												
Group Weighting (Revenue Apportionment Allocations - Docket No. G002/GR-09-1153)												
Residential	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67
Commercial Firm	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21
Commercial Demand Billed	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Interruptible	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Transport	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Allocated Revenue Requirements												
Residential	652,479.32	652,806.13	647,908.83	632,606.83	627,803.43	669,322.13	672,026.38	706,331.42	389,152.47	447,651.62	420,708.41	438,165.00
Commercial Firm	206,346.42	206,449.78	204,901.01	200,061.75	198,542.68	211,672.96	212,528.18	223,377.14	123,069.37	141,569.71	133,048.93	138,569.57
Commercial Demand Billed	20,392.28	20,402.50	20,249.44	19,771.20	19,621.08	20,918.68	21,003.20	22,075.35	12,162.39	13,990.69	13,148.62	13,694.20
Interruptible	54,859.22	54,886.70	54,474.94	53,188.38	52,784.52	56,275.33	56,502.70	59,387.01	32,719.20	37,637.70	35,372.37	36,840.08
Transport	36,521.70	36,539.99	36,265.87	35,409.36	35,140.50	37,464.45	37,615.82	39,536.00	21,782.31	25,056.73	23,548.62	24,525.73
Total	970,598.95	971,085.09	963,800.09	941,037.53	933,892.20	995,653.56	999,676.28	1,050,706.92	578,885.75	665,906.45	625,826.95	651,794.59
Sales by Customer Group (Billed by total Usage)												
Residential	68,347,473	56,468,255	46,220,639	25,081,110	14,740,988	8,906,845	6,435,105	6,570,745	8,647,552	19,322,602	38,000,795	60,517,630
Commercial Firm	36,782,234	30,859,812	26,556,962	13,434,879	9,702,243	4,956,830	3,909,831	4,147,409	5,295,143	10,516,422	19,887,615	31,614,352
Commercial Demand Billed	3,572,710	3,117,804	3,487,429	1,980,169	1,776,409	1,514,922	1,662,088	1,488,900	1,613,067	2,103,046	2,645,809	2,704,350
Interruptible	12,635,578	12,082,408	10,789,546	8,672,081	6,454,790	5,409,278	5,984,729	5,487,738	5,554,440	7,245,114	9,910,209	11,896,325
Transport	18,946,134	11,075,216	15,456,105	15,504,081	20,908,639	19,168,001	28,596,563	20,747,736	12,759,486	8,676,534	10,136,555	10,669,780
Total Therm Sales in Month	140,284,128	113,603,495	102,510,681	64,672,321	53,583,069	39,955,875	46,588,316	38,442,529	33,869,688	47,863,718	80,580,983	117,402,436
Flags												
Rate Change									x			
Rate Periods	0	0	0	0	0	0	0	0	1	1	1	1
Rate Period Calculations												
Revenue Requirement for Rate Period									4,728,458			
Remaining true-up in current calendar year									-2,206,044			
Carried-Forward Balance from Previous Month (unless January)												
Revenue Needs During Remaining Rate Period									2,522,414			
Retail Dth Sales in Rate Period									671,263,079			
Cost Per therm									$ 0.003758	$ 0.003758	$ 0.003758	$ 0.003758
Allocated Cost Per therm												
Residential									$ 0.010922	$ 0.010922	$ 0.010922	$ 0.010922
Commercial Firm									$ 0.006110	$ 0.006110	$ 0.006110	$ 0.006110
Commercial Demand Billed									$ 0.005274	$ 0.005274	$ 0.005274	$ 0.005274
Interruptible									$ 0.003860	$ 0.003860	$ 0.003860	$ 0.003860
Transport									$ 0.001570	$ 0.001570	$ 0.001570	$ 0.001570
Revenues												
Residential										211,041	415,045	660,974
Commercial Firm										64,255	121,513	193,164
Commercial Demand Billed										11,091	13,954	14,263
Interruptible										27,966	38,253	45,920
Transport										13,622	15,914	16,752
Forecast Revenues	0	0	0	0	0	0	0	0	0	327,977	604,680	931,071
Actual Revenues	3,163,660	2,642,628	1,844,781	1,221,378	606,284	431,894	422,173	445,843	168,733			
Actual & Forecast Total	3,163,660	2,642,628	1,844,781	1,221,378	606,284	431,894	422,173	445,843	168,733	327,977	604,680	931,071
Annual Total												12,811,102

Revenues

	Jan-17 Forecast	Feb-17 Forecast	Mar-17 Forecast	Apr-17 Forecast	May-17 Forecast	Jun-17 Forecast	Jul-17 Forecast	Aug-17 Forecast	Sep-17 Forecast	Oct-17 Forecast	Nov-17 Forecast	Dec-17 Forecast
Monthly Inputs												
Revenue Requirement	1,290,395	1,291,174	1,290,851	1,438,299	1,873,638	1,903,800	2,177,226	1,829,239	2,220,744	2,432,372	2,340,849	1,788,990
Remaining true-up in current calendar year	0	0	0	27,683	27,683	27,683	27,683	27,683	27,683	27,683	27,683	27,683
Revenue Carried-forward balance	2,976,253	3,337,260	3,872,420	280,095	1,744,225	3,577,575	5,651,830	7,431,701	9,515,740	11,170,771	11,688,510	10,348,399
Weighting												
Group Weighting (Revenue Apportionment Allocations - Docket No. G002/GR-09-1153)												
Residential	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67
Commercial Firm	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21
Commercial Demand Billed	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Interruptible	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Transport	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Allocated Revenue Requirements												
Residential	867,460.39	867,984.07	867,766.60	1,274,743.73	1,567,397.73	1,587,674.03	1,771,482.93	1,537,550.39	1,800,737.21	1,943,003.05	1,881,477.37	1,510,493.15
Commercial Firm	274,334.13	274,499.75	274,430.97	403,137.39	495,689.15	502,101.52	560,231.04	486,249.93	569,482.70	614,474.24	595,016.76	477,693.09
Commercial Demand Billed	27,111.20	27,127.57	27,120.77	39,840.25	48,986.72	49,620.42	55,365.10	48,053.88	56,279.40	60,725.71	58,802.81	47,208.25
Interruptible	72,934.42	72,978.45	72,960.17	107,178.03	131,783.83	133,488.62	148,942.92	129,274.32	151,402.57	163,364.01	158,191.05	126,999.40
Transport	48,554.99	48,584.30	48,572.13	71,352.15	87,733.09	88,868.03	99,156.50	86,062.42	100,793.97	108,757.12	105,313.29	84,547.93
Total	1,290,395.14	1,291,174.14	1,290,850.64	1,896,251.56	2,331,590.51	2,361,752.63	2,635,178.50	2,287,190.95	2,678,695.85	2,890,324.13	2,798,801.28	2,246,941.80
Sales by Customer Group (Billed by total Usage)												
Residential	68,861,376	59,404,237	47,082,742	25,555,639	12,888,931	4,993,430	5,558,191	5,431,833	7,452,745	19,055,161	38,127,796	61,320,811
Commercial Firm	36,426,385	33,165,068	26,489,198	15,344,005	6,691,944	6,345,321	5,007,380	4,500,372	5,461,499	10,612,269	20,189,801	32,444,525
Commercial Demand Billed	3,296,449	3,542,584	2,777,089	1,860,263	1,845,515	1,515,058	1,661,919	1,489,139	1,616,007	2,098,851	2,645,292	2,711,657
Interruptible	12,492,924	11,924,097	10,712,057	8,767,832	6,297,223	5,594,824	6,093,580	5,672,778	5,902,494	7,212,514	10,125,169	12,206,449
Transport	13,400,291	8,920,664	15,037,356	12,064,463	14,308,757	17,055,491	23,804,050	17,654,387	12,430,942	15,239,130	11,653,801	17,714,221
Total Therm Sales in Month	134,477,424	116,956,650	102,098,440	63,592,203	42,032,370	35,504,125	42,125,120	34,748,508	32,863,687	54,217,925	82,741,858	126,397,663
Flags												
Rate Change				X								
Rate Periods	0	0	0	2	2	2	2	2	2	2	2	2
Rate Period Calculations												
Revenue Requirement for Rate Period				18,005,158								
Remaining true-up in current calendar year				4,121,570								
Carried-Forward Balance from Previous Month (unless January)												
Revenue Needs During Remaining Rate Period				22,126,727								
Retail Dth Sales in Rate Period				514,223,459								
Cost Per therm	$ 0.003758	$ 0.003758	$ 0.003758	$ 0.043029	$ 0.043029	$ 0.043029	$ 0.043029	$ 0.043029	$ 0.043029	$ 0.043029	$ 0.043029	$ 0.043029
Allocated Cost Per therm												
Residential	$ 0.010922	$ 0.010922	$ 0.010922	$ 0.041738	$ 0.041738	$ 0.041738	$ 0.041738	$ 0.041738	$ 0.041738	$ 0.041738	$ 0.041738	$ 0.041738
Commercial Firm	$ 0.006110	$ 0.006110	$ 0.006110	$ 0.023123	$ 0.023123	$ 0.023123	$ 0.023123	$ 0.023123	$ 0.023123	$ 0.023123	$ 0.023123	$ 0.023123
Commercial Demand Billed	$ 0.005274	$ 0.005274	$ 0.005274	$ 0.017179	$ 0.017179	$ 0.017179	$ 0.017179	$ 0.017179	$ 0.017179	$ 0.017179	$ 0.017179	$ 0.017179
Interruptible	$ 0.003860	$ 0.003860	$ 0.003860	$ 0.012184	$ 0.012184	$ 0.012184	$ 0.012184	$ 0.012184	$ 0.012184	$ 0.012184	$ 0.012184	$ 0.012184
Transport	$ 0.001570	$ 0.001570	$ 0.001570	$ 0.004636	$ 0.004636	$ 0.004636	$ 0.004636	$ 0.004636	$ 0.004636	$ 0.004636	$ 0.004636	$ 0.004636
Revenues												
Residential	752,104	648,813	514,238	1,066,641	537,958	208,416	231,988	226,714	311,063	795,324	1,591,378	2,559,408
Commercial Firm	222,565	202,639	161,849	354,799	154,738	146,723	115,786	104,062	126,286	245,388	466,849	750,215
Commercial Demand Billed	17,385	18,684	14,646	31,957	31,704	26,027	28,550	25,582	27,761	36,056	45,443	46,584
Interruptible	48,223	46,027	41,349	106,827	76,725	68,167	74,244	69,117	71,916	87,877	123,365	148,723
Transport	21,038	14,005	23,609	55,931	66,335	79,069	110,356	81,846	57,630	70,649	54,027	82,123
Forecast Revenues	1,061,316	930,168	755,690	1,616,156	867,461	528,402	560,923	507,321	594,656	1,235,294	2,281,062	3,587,053
Actual Revenues												
Actual & Forecast Total	1,061,316	930,168	755,690	1,616,156	867,461	528,402	560,923	507,321	594,656	1,235,294	2,281,062	3,587,053
Annual Total												14,525,502

Revenues

	Jan-18 Forecast	Feb-18 Forecast	Mar-18 Forecast	Apr-18 Forecast	May-18 Forecast	Jun-18 Forecast	Jul-18 Forecast	Aug-18 Forecast	Sep-18 Forecast	Oct-18 Forecast	Nov-18 Forecast	Dec-18 Forecast
Monthly Inputs												
Revenue Requirement	1,512,040	1,513,256	1,516,971	1,656,787	2,065,326	2,106,203	2,373,340	2,078,032	2,476,707	2,705,346	2,646,781	2,150,455
Remaining true-up in current calendar year	0	0	0	0	0	0	0	0	0	0	0	0
Revenue Carried-forward balance	7,827,931	5,858,406	4,542,349	319,223	1,903,114	3,906,727	6,165,105	8,177,573	10,446,190	12,306,510	12,872,743	11,465,504
Weighting												
Group Weighting (Revenue Apportionment Allocations - Docket No. G002/GR-09-1153)												
Residential	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67
Commercial Firm	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21
Commercial Demand Billed	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Interruptible	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Transport	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Allocated Revenue Requirements												
Residential	1,016,459.53	1,017,277.36	1,019,774.52	1,453,050.12	1,727,688.02	1,755,167.62	1,934,748.80	1,736,229.77	2,004,236.48	2,157,937.48	2,118,567.76	1,784,915.89
Commercial Firm	321,455.08	321,713.71	322,503.44	459,526.74	546,380.91	555,071.33	611,863.83	549,082.24	633,839.29	682,447.20	669,996.53	564,479.21
Commercial Demand Billed	31,767.95	31,793.51	31,871.56	45,412.95	53,996.35	54,855.19	60,467.74	54,263.31	62,639.47	67,443.17	66,212.73	55,784.93
Interruptible	85,461.99	85,530.75	85,740.71	122,169.70	145,260.73	147,571.16	162,670.01	145,978.90	168,512.40	181,435.29	178,125.16	150,072.34
Transport	56,895.03	56,940.80	57,080.58	81,332.63	96,705.13	98,243.27	108,295.09	97,183.25	112,184.58	120,787.80	118,584.13	99,908.39
Total	1,512,039.58	1,513,256.13	1,516,970.80	2,161,492.14	2,570,031.15	2,610,908.57	2,878,045.46	2,582,737.47	2,981,412.22	3,210,050.93	3,151,486.31	2,655,160.76
Sales by Customer Group (Billed by total Usage)												
Residential	69,752,714	59,232,083	47,009,344	25,408,765	12,708,275	4,815,721	4,859,028	5,177,464	7,497,429	18,679,010	38,046,055	61,469,314
Commercial Firm	37,016,282	33,033,005	26,787,953	15,591,407	6,935,301	6,777,127	4,885,807	4,658,080	5,888,823	10,577,655	20,375,604	32,692,396
Commercial Demand Billed	3,291,095	3,543,192	2,783,752	1,855,368	1,846,163	1,518,496	1,659,247	1,489,639	1,619,562	2,095,751	2,645,516	2,712,061
Interruptible	12,166,824	11,798,758	10,808,534	8,421,694	6,211,900	5,755,554	5,862,225	5,665,270	6,158,529	7,014,704	9,956,386	12,096,692
Transport	13,042,023	9,082,201	15,535,243	13,547,994	14,062,385	16,632,149	26,187,948	16,954,006	15,360,313	8,676,534	10,136,555	12,236,999
Total Therm Sales in Month	135,268,937	116,689,239	102,924,826	64,825,228	41,764,024	35,499,047	43,454,255	33,944,459	36,524,656	47,043,654	81,160,116	121,207,462
Flags												
Rate Change				X								
Rate Periods	0	0	0	3	3	3	3	3	3	3	3	3
Rate Period Calculations												
Revenue Requirement for Rate Period				20,258,976								
Remaining true-up in current calendar year				4,542,349								
Carried-Forward Balance from Previous Month (unless January)												
Revenue Needs During Remaining Rate Period				24,801,325								
Retail Dth Sales in Rate Period				505,422,902								
Cost Per therm	**$ 0.043029**	**$ 0.043029**	**$ 0.043029**	**$ 0.049070**	**$ 0.049070**	**$ 0.049070**	**$ 0.049070**	**$ 0.049070**	**$ 0.049070**	**$ 0.049070**	**$ 0.049070**	**$ 0.049070**
Allocated Cost Per therm												
Residential	$ 0.041738	$ 0.041738	$ 0.041738	$ 0.047753	$ 0.047753	$ 0.047753	$ 0.047753	$ 0.047753	$ 0.047753	$ 0.047753	$ 0.047753	$ 0.047753
Commercial Firm	$ 0.023123	$ 0.023123	$ 0.023123	$ 0.025645	$ 0.025645	$ 0.025645	$ 0.025645	$ 0.025645	$ 0.025645	$ 0.025645	$ 0.025645	$ 0.025645
Commercial Demand Billed	$ 0.017179	$ 0.017179	$ 0.017179	$ 0.019239	$ 0.019239	$ 0.019239	$ 0.019239	$ 0.019239	$ 0.019239	$ 0.019239	$ 0.019239	$ 0.019239
Interruptible	$ 0.012184	$ 0.012184	$ 0.012184	$ 0.013766	$ 0.013766	$ 0.013766	$ 0.013766	$ 0.013766	$ 0.013766	$ 0.013766	$ 0.013766	$ 0.013766
Transport	$ 0.004636	$ 0.004636	$ 0.004636	$ 0.005717	$ 0.005717	$ 0.005717	$ 0.005717	$ 0.005717	$ 0.005717	$ 0.005717	$ 0.005717	$ 0.005717
Revenues												
Residential	2,911,339	2,472,229	1,962,076	1,213,345	606,858	229,965	232,033	247,239	358,025	891,979	1,816,813	2,935,344
Commercial Firm	855,927	763,822	619,418	399,842	177,856	173,799	125,297	119,456	151,019	271,264	522,532	838,396
Commercial Demand Billed	56,538	60,868	47,822	35,695	35,518	29,214	31,922	28,659	31,159	40,320	50,897	52,177
Interruptible	148,241	143,756	131,691	115,933	85,513	79,231	80,699	77,988	84,778	96,564	137,060	166,523
Transport	60,463	42,105	72,021	77,454	80,395	95,086	149,717	96,926	87,815	49,604	57,951	69,959
Forecast Revenues	4,032,507	3,482,781	2,833,028	1,842,269	986,140	607,296	619,668	570,269	712,796	1,349,731	2,585,253	4,062,400
Actual Revenues												
Actual & Forecast Total	4,032,507	3,482,781	2,833,028	1,842,269	986,140	607,296	619,668	570,269	712,796	1,349,731	2,585,253	4,062,400
Annual Total												23,684,138

U.S. Department of Transportation

Pipeline and Hazardous Materials Safety Administration

Administrator

1200 New Jersey Avenue SE
Washington, DC 20590

DEC 19

Mr. Tony Clark
Chairman of the Board and President
National Association of Regulatory Utility Commissioners
1101 Vermont Avenue, NW
Suite 200
Washington, DC 20005

Ms. Collette Honorable
Chair, NARUC Pipeline Safety Task Force
National Association of Regulatory Utility Commissioners
1101 Vermont Avenue, NW
Suite 200
Washington, DC 20005

Dear Mr. Clark and Ms. Honorable:

As U.S. Department of Transportation (DOT) and the National Association of Regulatory Utility Commissioners (NARUC) continue to support efforts to accelerate the repair, rehabilitation, and replacement of high-risk infrastructure in pipeline systems, we appreciate the NARUC's continued diligence in promoting rate mechanisms that will encourage and will enable pipeline operators to take reasonable measures to repair, rehabilitate or replace high-risk gas pipeline infrastructure. We have prepared, and attached, a white paper on state pipeline infrastructure replacement programs in the hope that you will share it with your members as a resource for encouraging more States to adopt alternative or more flexible rate mechanisms that will facilitate the replacement or repair of high-risk pipelines.

As you know, the Pipeline and Hazardous Materials Safety Administration (PHMSA) has regulatory authority in regard to the safety of our nation's pipelines. PHMSA, however, does not have the authority to determine the routing, rates, or other terms and conditions of service for gas pipelines. The Federal Energy Regulatory Commission makes these determinations for interstate gas pipelines, and the State public utility commissions you represent typically do the same for intrastate gas pipelines. Most State commissions are also responsible for oversight of intrastate pipeline safety through certifications or agreements with PHMSA.

Many State public utility commissions have encouraged the timely repair, rehabilitation, and replacement of high-risk gas pipeline infrastructure through special rate mechanisms. Some legislatures have also provided their State public utility commissions with specific statutory authority to approve such programs for intrastate gas lines. A comprehensive list of these programs is available at http://opsweb.phmsa.dot.gov/pipelineforum/pipeline-systems/state-pipeline-system/state-replacement-programs/.

We believe that the timely repair, rehabilitation, and replacement of high-risk gas pipeline infrastructure are critical to ensuring public safety. A series of recent gas pipeline accidents, including the September 9, 2010 San Bruno, California accident, the January 19, 2011 Philadelphia, Pennsylvania accident, and the February 10, 2011 accident, show the terrible loss of life and property that can occur without adequate attention to the integrity of pipeline infrastructure.

PHMSA believes that an effective program for ensuring the timely rehabilitation, repair, or replacement of high-risk gas pipelines might have helped prevent these accidents. Accordingly, we recommend that State public utility commissions consider accelerating work on the following kinds of high-risk intrastate gas infrastructure in the future:

- Cast iron gas mains, which can be prone to failure as a result of graphitization or brittleness;
- Plastic pipe manufactured in the 1960s to the early 1980s, which is susceptible to premature failures as a result of brittle-like cracking;
- Mechanical couplings used for joining and pressure sealing pipe, which are prone to failure under certain conditions;
- Bare steel pipe without adequate corrosion control (i.e., cathodic protection or coating);
- Copper piping;
- Older pipe, if it is vulnerable to failure from time-dependent forces, such as corrosion, stress corrosion cracking, settlement, or cyclic fatigue factor; and
- Pipelines with inadequate construction records or assessment results to verify their integrity.

PHMSA requests your support in ensuring that State commissions implement effective programs for the timely repair, replacement, and rehabilitation of high-risk gas pipeline infrastructure.

I look forward to continuing to work with the NARUC on pipeline safety and welcome any thoughts that you have on the issues discussed in this letter. Please send your response to Jeffrey Wiese, Associate Administrator for Pipeline Safety, or to contact me if you have any questions or concerns.

Regards,

Cynthia L. Quarterman

Enclosure: White Paper

UNITED STATES DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION

White Paper on State Pipeline Infrastructure Replacement Programs

Prepared for

National Association of Regulatory Commissioners

December 2011

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Introduction

Under the leadership of Transportation Secretary Ray LaHood and Administrator Cynthia Quarterman, the Pipeline and Hazardous Materials Safety Administration (PHMSA) has issued a Call to Action with the goal of accelerating the rehabilitation, repair, and replacement of high-risk pipeline infrastructure. This effort comes on the heels of several high profile pipeline accidents, including two recent gas distribution line explosions in Pennsylvania that resulted in multiple deaths.

As part of Secretary LaHood's Call to Action, PHMSA has prepared this white paper to urge State public utility commissions to expand the use of pipeline infrastructure replacement programs. It includes an overview of natural gas ratemaking, a discussion of the need to take prompt action to remediate high-risk pipeline infrastructure, and a description of the various State programs that are being used for that purpose.

Executive Summary

Public safety requires prompt action to repair, remediate, and replace high-risk gas pipeline infrastructure, including cast iron mains, certain vintages of plastic pipe and mechanical coupling installations, bare steel pipe without adequate corrosion control, and copper piping. Several recent gas pipeline accidents show the terrible consequences that can occur if such action is not taken.

The Federal Energy Regulatory Commission establishes rates for interstate natural gas pipeline service under the "just and reasonable" standard provided in the Natural Gas Act of 1938. State public utility commissions (and in some cases local authorities) establish rates for intrastate natural gas pipeline service. While based on State and local laws, those determinations are generally made on the basis of a formula that is similar to the "just and reasonable" standard.

Pipeline infrastructure replacement programs for gas distribution systems exist in nearly 30 States. Some State Public utility commissions have used their traditional ratemaking authority to approve these programs, the terms and conditions of which are established under a generally applicable statutory provision. Other State public utility commissions have specific authority to approve such programs. The terms, conditions, and cost recovery mechanisms of these programs vary by statute. Whether as part of the traditional ratemaking process or in a separate proceeding, PHMSA is encouraging the States to accelerate the remediation of high-risk gas pipeline infrastructure.

PHMSA intends to focus on this issue in implementing the new Gas Distribution Pipeline Integrity Management Program Rule and as part of the annual certification process for State pipeline safety programs. PHMSA is also willing to provide other assistance to State public utility commissions who are seeking to establish or improve programs for the repair, rehabilitation, and replacement of high-risk pipeline infrastructure.

I. General Ratemaking Principles

Federal Ratemaking

The Federal Energy Regulatory Commission (FERC) regulates the interstate sale and transportation of natural gas under the Natural Gas Act of 1938 (NGA). The NGA imposes a "just and reasonable" requirement on the rates charged for interstate pipeline services, a standard that requires FERC to consider both the interests of pipeline operators and ratepayers. FERC utilizes varying ratemaking methodologies to meet the "just and reasonable" standard, such as selective discounting, market-based rates, and negotiated rates. However, the underlying premise that ratemaking should be based on the cost of providing service remains a strong principle in rate-making proceedings. Accordingly, cost-of-service ratemaking is the primary method that FERC uses to establish rates.

Cost-of-service ratemaking bases rates on the cost of service and affords the pipeline a reasonable rate of return. The Cost-of-Service:

> Includes the product of the pipeline's Rate Base (which is the pipeline's investment) and the Overall Rate of Return, plus its Operation and Maintenance Expenses (O&M), Administrative and General Expenses (A&G), Depreciation Expense, Non-Income Taxes and Income Taxes, less Revenue Credits.

In this equation, the Rate Base captures the total amount invested in the pipeline and is used to calculate the permissible return on investment. The Overall Rate of Return is a product of the pipeline's capitalization ratio, the cost of debt, and the rate of return that is allowed on the pipeline's equity. Total cost-of-service captures the amount of rate revenue that a pipeline company must charge in order to maintain profitability and remain an attractive prospect for future investment.

FERC applies cost-of-service and other rate methodologies in rate proceedings to set initial rates for new or expanding pipelines, increase rates for existing pipelines, and require prospective changes to existing rates. Applications to establish new or expanded pipeline service must be approved by FERC and are required to meet a "public convenience and necessity" standard. In a certificate proceeding, FERC authorizes initial rates that remain in effect until a further rate proceeding is held. In a general Section 4 rate case, a pipeline files to increase rates and is required to prove that its proposal is "just and reasonable." Alternatively, in a Section 5 rate proceeding, FERC may require prospective rate changes, if it is determined that a pipeline's rates no longer meet the "just and reasonable" standard.[1]

State Ratemaking

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[1] Cost-of-Service Rates Manual, Federal Energy Regulatory Commission, June 1999.

State public utility commission (PUCs) regulate the intrastate sale of natural gas, which includes establishing rates for the end user. State PUCs evaluate ratemaking proposals according to a variety of legislative mandates, policy objectives, and consumer interests, but have traditionally set rates according to the "just and reasonable" standard. As articulated by the National Regulatory Research Institute, these rates share four general characteristics. First, rates are reflective of "an efficient or prudent utility" and, therefore, do not include those costs that a utility could eliminate without impairing efficiency or profitability. Second, rates incorporate the natural consequences of a utility's provision of service at different levels and to different classes of customers. Third, rates are set at a level that provides the utility with an acceptable return to ensure that it remains an attractive candidate for new capital investment. Lastly, the utility's provision of service should be nondiscriminatory. Within these general principles, the States use varying methods to establish rates, some of which are outlined below.

Rates for Investor-Owned Local Gas Distribution Companies

Local distribution companies are privately-owned utilities and are required to provide distribution of natural gas to any customer within its geographic franchise area upon reasonable request. These utilities own the natural gas being distributed for their "sales customers" and get paid a fee for the distribution service. Local distribution companies do not earn any money from the sale of the natural gas itself, whether the utility owns the natural gas or transports it on behalf of the customer. The companies simply pass the cost of the gas straight through to the customer. Customers who have purchased their natural gas from a third party supplier or market and wish the distribution company to transport the gas to their business or home, commonly referred to as "transportation customers," pay a fee for the transport of natural gas over the local distribution company's pipeline.

State PUCs regulate the rates, terms, and conditions of service for investor-owned natural gas distribution systems. Local agencies generally perform that regulatory function for publicly-owned distribution utilities. These State and local authorities are also responsible for ensuring that the operation of these utilities serves the public interest. In some cases, that may require prohibiting a utility from turning off a residential customer's gas service for nonpayment during cold weather, asking for safety-driven changes beyond those required by the Federal and State safety regulators, or requiring utilities to offer energy conservation programs.

Natural gas utilities are required to post the rates, terms, and other conditions of service with their State PUCs, and customers must pay the posted rates to obtain the applicable service. Utilities also have information on file with State PUCs on the current "purchased gas adjustment charge." These charges account for market-driven changes in the price the utility pays for the gas supplied to its customers.

Rates for Publicly-Owned Local Gas Utility Systems

Publicly-owned gas utility systems are non-profit enterprises that are owned by the citizens they serve. They include municipal gas distribution systems, public utility districts, county districts, and other public agencies that have natural gas distribution facilities. These utilities own the natural gas that is provided to their customers and charge a fee for the distribution service. Publicly-owned utilities also pass through and recover the cost of acquiring the natural gas that is distributed.

Unlike privately-owned pipeline systems, most State PUCs do not establish rates for publicly-owned gas distribution systems. That function is typically performed by a local body, like a city or county council or utility board. There is no requirement that the rate charged by the utility be based on the cost of service, and the utility may charge whatever rate is established by its governing body.

Rates for publicly-owned utilities do not include costs for return on investment or profit, and any necessary capital is raised by issuing bonds. Customers of municipal utilities pay the purchased gas adjustment charge for the amount of gas the utility distributes during the billing period. Rate changes must be approved by the city council or the utility board.

II. Need for Repair, Rehabilitation, and Replacement of High-Risk Gas Pipeline Infrastructure

The safety of natural gas distribution systems has improved significantly since the enactment of the Natural Gas Pipeline Safety Act of 1968, which provided DOT with the authority to establish safety standards for natural gas systems. A number of serious incidents in natural gas distribution systems, however, still occur each year, and many of those incidents are caused by failures of high-risk pipeline infrastructure. Thus, there is a need to improve pipeline safety by repairing, rehabilitating and replacing high risk pipe.

High-risk pipeline infrastructure is piping or equipment that is no longer fit for service. As discussed below, that lack of fitness can be the product of a variety of factors.

- Cast iron gas mains and service lines can be prone to failure as a result of graphitization or brittleness. The installation of cast iron pipe dates to the 1830s, and remained prevalent until the post-World War II period. Many major urban areas, including Philadelphia, PA; Boston, MA; Baltimore, MD; Washington, DC; Detroit, MI; Chicago, IL; and San Francisco, CA, still have cast iron pipe in their natural gas distribution systems.[2]

- Certain vintages of plastic pipe are susceptible to premature failures as a result of brittle-like cracking. In April 1998, the National Transportation Safety Board (NTSB) released a Special Investigation Report on Brittle-Like Cracking in Plastic Pipe for Gas Service. NTSB found that the long-term strength and resistance of plastic pipe to brittle-like cracking may have been overrated for much of the plastic pipe manufactured and installed from the 1960s through the early 1980s. The NTSB

[2] http://opsweb.phmsa.dot.gov/pipelineforum/reports-and-research/cast-iron-pipeline/

also found that any potential public safety hazards from these failures are likely to be limited to locations where stress intensification exists. In response to the NTSB report and subsequent investigations, PHMSA issued four advisory bulletins on the susceptibility of certain kinds of older plastic pipe to brittle-like cracking.[3]

- Mechanical coupling installations are devices that are used for the joining and pressure sealing of two pieces of pipe. These devices are prone to failure under certain conditions. In March 2008, PHMSA issued an Advisory Bulletin (ADB) on the use of mechanical couplings in natural gas distribution systems. The ADB noted that these devices are more likely to fail when there is inadequate restraint for the potential stresses on the two pipes, when the couplings are incorrectly installed or supported, or when components experience age-related deterioration. The ADB also noted that inadequate leak surveys can fail to detect a coupling in need of repair and lead to more serious incidents.[4]

- Pipelines lacking adequate construction records or assessment results to verify their integrity. In January 2011, PHMSA issued an ADB on the need to use traceable, verifiable, and complete records in establishing the maximum allowable operating pressures and developing and implementing integrity management programs for natural gas pipelines. The ADB responded to an NTSB recommendation, which resulted from its investigation of the September 2010 intrastate natural gas transmission line rupture in San Bruno, California, which is discussed below.

- Other kinds of pipe installations, including bare steel pipe without adequate corrosion control (i.e., cathodic protection or coating) and copper piping, are also more susceptible to failure.

- Age of pipe should be considered in determining whether pipeline infrastructure is vulnerable to failure from time-dependent forces, like corrosion, stress corrosion cracking, settlement, or cyclic fatigue.

Several recent gas pipeline accidents show the grave consequences that can occur if high-risk gas pipeline infrastructure is not properly repaired, rehabilitated, or replaced. For example,

- On September 9, 2010, an intrastate natural gas transmission line ruptured in San Bruno, California. The ensuing explosion and fire resulted in 8 fatalities, multiple injuries, and destroyed 38 homes. NTSB has released a final report on the cause of the accident and concluded that the failure was the result of an improperly-welded section of pipe that had been installed in 1956 and never subjected to hydrostatic pressure testing.

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[3] 72 FR 51301.

[4] 73 FR 11695.

- On January 19, 2011, a natural gas explosion and fire in a natural gas distribution system killed one person and injured five others in Philadelphia, Pennsylvania. The cause of the accident remains under investigation, but preliminary reports indicate that the source of the gas leak was a 12-inch cast iron gas main installed in the 1920s.

- On February 10, 2011, another natural gas explosion and fire in a natural gas distribution system killed five people and destroyed several homes in Allentown, Pennsylvania. The cause of the accident remains under investigation, but preliminary reports indicate that the source of the gas leak was an 83-year-old, 12-inch cast iron gas main.

Recognizing that prompt action to replace these high-risk gas pipelines might have prevented each of these accidents, Transportation Secretary Ray LaHood issued a Call to Action in April 2009 encouraging the States to expand and accelerate the use of such programs.[5] Twenty-two States responded to the Secretary's initiative by providing PHMSA with information on their efforts to remediate high-risk pipeline infrastructure.

After reviewing that information and performing additional research, PHMSA decided to prepare the following overview of the State pipeline infrastructure replacement programs. PHMSA urges the appropriate regulatory authorities will use this information to accelerate their efforts to repair, rehabilitate, and replace high-risk gas pipeline infrastructure in their jurisdictions. In addition to the analysis provided below, a comprehensive list of all of these programs is included in Appendix I.

III. <u>Using Traditional Ratemaking Authority to Establish Infrastructure Replacement Programs</u>

Several state public utility commissions have used their traditional ratemaking authority to approve pipeline infrastructure replacement programs. The examples discussed below show how that authority can be used to ensure the timely repair, rehabilitation, and replacement of high-risk pipeline infrastructure without additional legislation.

New Jersey

Originally established in 1911 as the Department of Public Utilities, the mission of the New Jersey Board of Public Utilities (BPU) is "[t]o ensure the provision of safe, adequate and proper utility and regulated service at reasonable rates, while enhancing the quality of life for the citizens of New Jersey and performing these public duties with integrity, responsiveness and efficiency."[6] The Division of Energy is responsible for regulating the State's four natural gas

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[5] http://opsweb.phmsa.dot.gov/pipelineforum/

[6] http://www.nj.gov/bpu/about/index.html.

service providers: Elizabethtown Gas, New Jersey Natural Gas (NJNG), PSE&G, and South Jersey Gas.[7]

As part of then-Governor Jon Corzine's economic stimulus plan, BPU approved accelerated pipeline infrastructure replacement programs using its plenary authority to require or enable natural gas companies to provide safe, adequate, and proper service to its customer.[8] In a December 22, 2009 provisional order, BPU approved Elizabethtown Gas's petition to implement a Utility Enhancement Infrastructure Rider (i.e., a rate increase to allow for an accelerated recovery of the costs associated with performing certain gas-distribution infrastructure related projects). The list of qualifying projects included the replacement of 29 miles of 10- and 12-inch and 41.9 miles of 4-inch cast iron gas mains; the installation of 6 miles of 8-inch main and 20 miles of 12-inch main in certain locations. In a subsequent filing, Elizabethtown petitioned BPU to approve an additional rate increase to cover greater-than-anticipated costs for each of these projects.[9]

Likewise, in an April 29, 2009 order, BPU approved NJNG's petition to implement an Accelerated Infrastructure Investment Program (AIIP), i.e., a rate increase to allow for an accelerated recovery of the costs associated with performing 14 infrastructure projects. In a March 30, 2011, BPU approved NJNG's petition to add 9 additional projects to the AIIP. The total anticipated cost for these projects is approximately 130 million dollars.[10]

Kentucky

Created in 1934, the Kentucky Public Service Commission (KPSC) is a three member administrative body with authority to regulate investor-owned natural gas companies. KPSC does not regulate natural gas utilities subject to the control of cities or political subdivisions, or those served by the Tennessee Valley Authority.[11]

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[7] http://www.state.nj.us/bpu/index.shtml

[8] Specifically, § 48: 2-23 states:

The board may, after public hearing, upon notice, by order in writing, require any public utility to furnish safe, adequate and proper service, including furnishing and performance of service in a manner that tends to conserve and preserve the quality of the environment and prevent the pollution of the waters, land and air of this State, and including furnishing and performance of service in a manner which preserves and protects the water quality of a public water supply, and to maintain its property and equipment in such condition as to enable it to do so.

The board may, pending any such proceeding, require any public utility to continue to furnish service and to maintain its property and equipment in such condition as to enable it to do so.

[9] *See* http://www.elizabethtowngas.com/Universal/RatesandTariff/RegulatoryInformation.aspx

[10] *See* http://www.njng.com/regulatory/filings.asp

[11] http://psc.ky.gov/

In a January 31, 2002 order, KPSC approved a petition filed by Duke Energy Kentucky, Inc. (Duke) for approval of an Accelerated Main Replacement Program (AMRP) Rider, which was designed to allow Duke to reduce the time for replacing its cast iron and bare steel mains from 15 years to 10 years. The Kentucky Attorney General appealed that order, arguing that KPSC lacked the authority to approve such a program outside of the confines of a general rate case. The Kentucky Supreme Court later ruled that KPSC had the power to approve the AMRP Rider under its plenary authority to ensure that rates are "fair, just and reasonable."[12]

Indiana

Established in the early 20th century, the Indiana Regulatory Utility Commission (IRUC) is comprised of five Commissioners who are appointed by the Governor to staggered four-year terms. The Gas Division is responsible for regulating the rates and terms and conditions of service for intrastate gas utilities.[13]

IRUC uses a deferred accounting alternative to allow eligible infrastructure investment costs to be diverted to a special deferred account. In the next rate case, the costs are amortized, recovered in rates, and the balance in the special deferred account is either reduced or eliminated. Gas utilities must establish, through the ratemaking proceeding, that all infrastructure investment costs in such accounts are properly accounted for. The assets in these deferred accounts may accrue interest, which isamortized and recoverable. The amount and type of infrastructure costs may be limited and are subject to state approval.

IRUC has approved Vectren Corporation's program to target 90 miles of pipeline replacements per year, as part of a broader, 20-year effort to replace 1,700 miles of aging bare steel and cast iron mains in Indiana and Ohio.[14]

IV. <u>Using Specific Ratemaking Authority to Establish Infrastructure Replacement Programs</u>

Several states have provided their public utility commissions with specific statutory authority to approve pipeline infrastructure replacement programs. Some states, like Missouri, Kansas, and Nebraska, have enacted statutes with detailed eligibility requirements and cost-recovery formulas. Other states, like Ohio, have adopted statutes that provide their commissions with far more flexibility and discretion. Still other states, like Texas and Virginia, fall somewhere in between.

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[12] *Kentucky Public Service Commission v. Commonwealth of Kentucky*, 324 S.W.3d 373 (KY 2010).

[13] http://www.in.gov/iurc/

[14] *http://www.enengineering.com/pdf/p&gj4_05.pdf*

Infrastructure Replacement Surcharge: Missouri, Kansas, and Nebraska

Missouri, Kansas, and Nebraska have adopted statutes that authorize the approval of infrastructure replacement surcharges. Local distribution companies are allowed to charge current customers for the cost of replacing existing infrastructure through the performance of certain projects. A specific formula is provided for determining the permissible amount of the surcharge; procedural requirements are also included to facilitate commission review and approval.

Missouri and Kansas

Established in 1913, the Missouri Public Service Commission (MPSC) regulates local gas distribution companies and is composed of five commissioners who are appointed by the governor.[15] Founded two decades later, the Kansas Corporation Commission (KCC) regulates natural gas companies and is composed of three commissioners who are appointed by the Governor for 4-year terms with the approval of the Senate.[16]

On July 9, 2003, the Missouri General Assembly enacted a statute allowing gas corporations to petition MPSC for approval of an infrastructure system replacement surcharge (ISRS) as of August 28, 2003. Using Missouri's ISRS statute as a model, the Kansas Legislature enacted the Gas Safety and Reliability Act (GSRA) three years later, on April 12, 2006. The GSRA provided that as of July 1, 2006, a natural gas public utility could petition the KCC to establish or change gas system reliability surcharge (GSRS) rate schedules.

These two statutes are similar in many respects and include provisions that define the kinds of gas utility projects which are eligible for a cost recovery surcharge, establish a formula for determining and limiting the amount of that surcharge, and prescribe the procedural requirements that must be met before a surcharge can be imposed.

Both statutes generally limit eligible infrastructure system replacements to gas utility plant projects that:

- Do not increase revenues by directly connecting the infrastructure replacement to new customers;
- Are in service and used and useful;
- Were not included in the gas corporation's rate base in its most recent general rate case; and
- Replace, or extend the useful life of an existing infrastructure.

The statutes also list the kinds of "gas utility plant projects" that are eligible for the surcharge:

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[15] http://psc.mo.gov/

[16] http://www.kcc.state.ks.us/index.htm

- Mains, valves, service lines, regulator stations, vaults, and other pipeline system components installed to comply with State or Federal safety requirements as replacements for existing facilities that are in deteriorated condition;

- Main relining projects, service line insertion projects, joint encapsulation projects, and other similar projects extending the useful life, or enhancing the integrity of pipeline system components for compliance with State or Federal safety requirements; and

- Facility relocations as a result of construction or improvement of a highway, road, street, public way, or other public work by or on behalf of the United States, the State (or political subdivision thereof), or another entity having the power of eminent domain provided that the costs related to such projects have not been reimbursed to the gas corporation.

The two statutes also prescribe a formula for determining the maximum amount and duration of the surcharge:

- MPSC and KCC cannot approve a surcharge that produces a total annualized surcharge revenue below the lesser of $1,000,000 or 1/2 percent of the gas company's base revenue level or exceeds 10 percent of the base revenue approved at the gas company's most recent general rate proceeding.

- A surcharge cannot be approved for a gas company that has not had a general rate proceeding decided or dismissed within a certain number of months (the past 36 months for Missouri and the past 60 months for Kansas), unless the gas company has filed for one or is the subject of a new proceeding.[17]

Finally, there are also procedural requirements that must be met to authorize the surcharge:

- Gas companies that petition MPSC or KCC for a surcharge must submit a proposed ISRS or GSRS and supporting documentation.

- MPSC and KCC must publish notice of that filing, and their respective staffs are required to confirm underlying costs and submit a report within 60 days.

- MPSC and KCC may hold a hearing on the petition but must issue an order that is effective no later than 120 days after the filing.

[17] As originally enacted, the GSRA prohibited a utility from collecting a GSRS for any period exceeding 60 months unless a filing had been made or was subject to a new proceeding. However, on April 13, 2011, the Kansas Legislature amended the GSRA to allow the KCC, on motion from a natural gas public utility, to extend that 60-month deadline for up to 12 months.

- A gas company cannot effectuate a change in its rates more often than twice every 12 months.

Nebraska

The Nebraska Public Service Commission (NPSC) regulates the rates and quality of service for investor-owned natural gas public utilities and is composed of five elected commissioners who serve 6-year terms.[18] On August 30, 2009, the Nebraska legislature enacted a statute allowing a jurisdictional utility to file an application and proposed rate schedule with NPSC to establish or change "infrastructure system replacement cost recovery charge rate schedules." Through this process, utilities may request an adjustment of their rates to recover costs for eligible infrastructure system replacements. Nebraska's legislation is largely bifurcated: utilities are treated differently depending on whether or not their prior rate filings were subject to negotiation.

NPSC is specifically disallowed from approving rate schedules that produce total annualized infrastructure system cost recovery charge revenue either:

- Below the lesser of one million dollars or one-half percent of the utility's base revenue level, as approved by the commission in the most recent general rate proceeding; or

- Exceeding ten percent of the utility's base revenue level, as approved by the commission in the most recent general rate proceeding.

Furthermore, NPSC cannot approve any rate schedules for a utility that has not had a general rate proceeding decided or dismissed by order within the 60 months immediately preceding the application for a infrastructure system replacement cost recovery charge. Utilities cannot collect a recovery rate for a period exceeding 60 months after the initial approval, unless that utility has filed for or is the subject of a new general rate proceeding within the 60-month period. (The rate may be collected until the effective date of a new rate schedule established as a result of a new general rate proceeding or until the rate proceeding is otherwise decided or dismissed by issuance of a commission order without new rates being established).

Two processes exist for establishing or changing a rate schedule. If the utility's last general rate filing was not subject to negotiation, the utility must submit to NPSC:

- A list of eligible projects;

- A description of the projects;

- The location of the projects;

[18] http://www.psc.state.ne.us/index.htm

- The purpose of the projects;
- The dates construction began and ended;
- The total expenses for each project at completion; and
- The extent to which such expenses are eligible for inclusion in the calculation of the infrastructure system replacement cost recovery charge.

After the public advocate conducts an examination of this information to verify the underlying costs, NPSC must require a report on this examination to be prepared and filed not later than 60 days after the application. NPSC must hold a hearing on the application and issue an order that is effective not later than 120 days after the application is filed (there is a good-cause 30-day extension). If NPSC finds that an application complies with the applicable requirements, an order is issued authorizing the utility to recover appropriate pretax revenue. Utilities may apply for a change in any infrastructure system replacement cost no more than once in any 12-month period.

If a utility's last general rate filing was subject to negotiation, it must submit to NPSC the schedules, supporting documentation, and a written notice for each city that will be affected by the charge. The notice must identify the cities that will be affected by the filing and copies must be provided to each such city. Affected cities have 30 days from that filing to adopt a resolution of intent to negotiate a charge rate with the utility. A copy of the resolution in support, or a resolution of rejection, of the offer to negotiate must be provided to the utility and NPSC within seven days of adoption.

If NPSC receives timely resolutions from cities that represent more than 50 percent of the ratepayers within the affected cities, to negotiate a recovery rate with the utility, the commission will certify the case for negotiation and will take no action until the negotiation period has expired. If agreement is reached, it must be put in writing and filed with the commission, which then must enter an order either approving or rejecting the rate within 30 days of the filing of the agreement. If agreement is not reached, the affected cities and the utility must submit all documentation within 14 days after the commission receives notice that the negotiations have failed. A hearing must be held not later than 35 days after the receipt of this report. If the commission receives resolutions from cities representing more than 50 percent of ratepayers that expressly reject negotiations, the rate review proceeds immediately.

Interim Rate Adjustment: Texas and Virginia

Texas

Established in 1891, the Texas Railroad Commission (TRC) has primary regulatory authority over various aspects of the oil and natural gas industry. The Gas Services Division regulates the day-to-day activities of approximately 200 natural gas utilities and is responsible for ensuring that a continuous, safe supply of natural gas is available to local consumers at the lowest, reasonable price. TRC has exclusive authority over the rates and terms of service for gas utilities in unincorporated areas and original jurisdiction over utilities at a city gate. TRC is composed of three members who are elected to serve 6-year terms.[19]

On May 16, 2003, the Texas Legislature enacted the Gas Reliability Infrastructure Program (GRIP) statute, which allows gas utilities to recover a return on capital expenditures made during the interim period between general rate cases.[20] Specifically, a gas utility may file a tariff or rate schedule with TRC providing for an interim rate adjustment within two years of the utility's last general rate case. That tariff or rate schedule must be filed at least 60 days before the proposed implementation date of the new rates. During that 60-day period, implementation of the new rates may be suspended by the TRC or an affected municipality for up to 45 days.

The allowable amount of the interim rate adjustment is based on values associated with the utility's return on investment, depreciation expenses, ad valorem taxes, revenue-related taxes, and incremental federal income taxes. The reasonableness and prudence of the investments recovered by an interim rate adjustment is subject to review in the utility's next general rate case. Until the TRC issues a final order approving the interim rate adjustment in that rate case, all amounts collected under the tariff or rate schedule before the filing of that rate case are subject to refund (including with interest, if appropriate). Any utility that implements an interim rate adjustment is required to file a general rate case no later than 180 days after the fifth anniversary of the date its interim rate became effective. The regulatory authority itself may also initiate a rate case at any time to review the reasonableness of the utility's rates.

It should also be noted that TRC has issued regulations mandating the removal, rehabilitation, or replacement of gas distribution pipeline facilities as part of their state pipeline safety program.[21] That includes requirements for the removal of compression couplings and, more recently, for the submission of a written risk-based program, by August 1, 2011, for the removal or replacement of all other distribution facilities.

Virginia

Established in 1902, the Virginia State Corporation Commission (VSCC) is composed of three commissioners who are elected by the General Assembly for 6-year terms. Its Division of Energy Regulation is responsible for providing assistance in regulating investor-owned natural gas utilities.[22]

On April 11, 2010, the SAVE Act (Steps to Advance Virginia's Energy Plan) was enacted, authorizing certain natural gas utilities to petition the State Corporation Commission

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[19] http://www.rrc.state.tx.us/

[20] Tex. Util.Code Ann. § 104.301.

[21] http://info.sos.state.tx.us/pls/pub/readtac$ext.ViewTAC?tac_view=5&ti=16&pt=1&ch=8&sch=C&rl=Y

[22] http://www.scc.virginia.gov/pue/index.aspx

(SCC) for a separate rider ("SAVE rider"), allowing for the recovery of certain costs associated with eligible infrastructure replacement projects. While utilities are still required to apply for the SAVE rider, the statute places restrictions on the VSCC approval process, ostensibly to wall off this process from traditional ratemaking.

Under the Act, an eligible "natural gas utility" is any investor-owned public service company that furnishes natural gas service to the public. Natural gas utilities may apply for "eligible infrastructure replacement" projects that:

- Enhance safety or reliability by reducing system integrity risks associated with customer outages, corrosion, equipment failures, material failures, natural forces, or other outside force damage;

- Do not increase revenues by directly connecting the infrastructure replacement to new customers;

- Reduce or have the potential to avoid greenhouse gas emissions; and

- Are not included in the natural gas utility's rate base in its most recent rate case or in the rate base filed with a performance based regulation plan.

Specifically, eligible "natural gas utility facility replacement projects" are intended to replace storage, peak shaving, transmission or distribution facilities used in the delivery of natural gas, or supplemental or substitute forms of gas sources by a natural gas utility. The act specifically delineates recoverable costs, including return on investment, depreciation, property taxes, and carrying costs of the eligible infrastructure replacement projects.

In order to qualify for the SAVE rider, utilities must file a petition with VSCC to establish a plan, which must include a completion timeline, a schedule of cost recovery, and a certification that the plan is "prudent and reasonable." Prior to approval, VSCC must provide notice and an opportunity for a hearing on the plan. SAVE plans must be approved or denied within 180 days; in the case of a denial, VSCC must specifically detail the reasons for the denial and the utility may refile, without prejudice, an amended plan within 60 days, at which point the Commission has an additional 60 days to approve or deny. VSCC is specifically prohibited from requiring the filing of rate case schedules in conjunction with the consideration of a SAVE plan. In addition, no other revenue requirement or ratemaking issues may be examined in conjunction with the consideration of an application filed pursuant to the SAVE Act.

At the end of each 12-month period that a SAVE rider is in effect, the utility must reconcile the difference between the eligible replacement costs and the amounts recovered under the SAVE rider. This reconciliation provides the basis for an adjustment to the SAVE rider, which VSCC must approve or deny within 90 days, whether it is an additional recovery or a refund. Finally, the Act states that this rider is in addition to all other costs that a utility is permitted to recover and cannot be considered as an offset to other VSCC-approved cost of service or revenue requirements. In addition, the rider cannot be included in the computation of a performance based regulation plan revenue-sharing mechanism.

In summary, the Virginia SAVE Act:

- Uses a rider for the recovery of certain eligible infrastructure costs;
- Uses a statutorily prescribed process that is separated from the ratemaking process;
- Includes an amendment process to incorporate increased project costs, but also requires refunds;
- Requires approval or denial within specific timeframe; and
- Restricts VSCC from considering any costs that the utilities are already allowed to recover in the consideration of whether a utility should be able to recover infrastructure costs.

Alternative Rate Plan: Ohio

Established in 1913, the Public Utilities Commission of Ohio (PUCO) regulates various public utilities in Ohio, including more than two dozen natural gas companies. Those companies provide gas service to more than 3 million users and operate a network of approximately 54,000 miles of regulated distribution lines. PUCO is composed of 5 commissioners who are appointed by the Governor for 5 year terms.[23]

Ohio Chapter 4901: 1-19 governs the filing and consideration of an alternative rate case by a natural gas company. Alternative rate plans may include automatic adjustments based on a specified index or changes in a specified cost. In its "alternative rate plan filing," the applicant must notify the commission and the consumer services department of its intent to file at least 30 days prior to the expected date of filing. The application (sample is included in rule appendix) must include the proposed rates, a summary of the proposed plan, a comparison of the typical "before" and "after" customer bill, and any waiver requests. In addition, the applicant must fully justify any proposal to deviate from the traditional rate of return regulation, including the rationale for the alternative plan, including "how it better matches actual experience of performance of the company in terms of costs and quality of service to its regulated customers."

PUCO may grant alternative rate regulation on the basis of this application. However, PUCO may subsequently determine that the natural gas company is not in substantial compliance with state policy, or on the motion of an adversely affected party, abrogate any order when (1) the commission determines that the findings are no longer valid and that modification or abrogation is in the public interest; and (2) the modification or abrogation is not made more than eight years after the effective date of the order, unless the affected natural gas company consents.

California

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[23] http://www.puco.ohio.gov/puco/

The California Public Utilities Commission (CPUC) is responsible for regulating intrastate natural gas pipelines in the State of California, except for municipal gas systems.[24] CPUC is composed of five commissioners who are appointed by the Governor.

On October 7, 2011, the Governor approved a package of pipeline safety bills with several new mandates for gas pipeline operators and CPUC. The relevant provisions include:

- Requiring operators of intrastate gas transmission lines to prepare and submit to CPUC a plan for pressure testing each line segment and to replace each segment that is not tested. Plans must include a timeline for completing all testing and replacements as soon as practicable with interim safety measures during implementation. Where warranted, segments must also be capable of accommodating inline inspection devices.

- Requiring gas pipeline operators to submit to CPUC for approval a plan for the safe and reliable operation of their gas pipeline facilities. Plans must be consistent with Federal pipeline safety laws and must address specific criteria, including: minimizing hazards and systemic risks; identifying safety-related systems that may be deployed; patrolling and inspecting for leaks; responding to reports of leaks; determining MAOP; ensuring qualified and adequately-sized workforce; and meeting applicable pipeline safety standards.

- Requiring gas pipeline operators to report to CPUC twice per year on the strategic planning and decisionmaking approach that is used to determine and rank pipeline safety, integrity, reliability, operations and maintenance activities, and inspections.

- Establishing that is the policy of the State and CPUC for each gas pipeline operator to place safety as its top priority. CPUC must take reasonable and appropriate action to carry out this policy, including through ratemaking.

- Requiring gas pipeline operators who recover expenses for integrity management program and related pipeline maintenance and repairs to have a balancing account, with any unspent money being returned to ratepayers at the end of each rate cycle.

In a June 2011 order, CPUC had previously used its general authority to require operators of intrastate natural gas transmission lines to submit comprehensive pressure testing implementation plans. The purpose of these plans is to achieve the orderly and cost effective replacement or testing of all natural gas transmission lines in the State. The plans permit the use of alternatives that achieve the same standard of safety, but must include a prioritized schedule based on risk assessment and maintaining service reliability, as well as cost estimates with proposed ratemaking. The plans also address the retrofitting of pipelines to accommodate the use of in-line inspection tools and, where appropriate, automated or remotely controlled shut off valves.

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[24] CA PUB UTIL §§ 2101 *et seq.*, 4351-61, 4451-64.

V. CONCLUSIONS

Nearly 30 State public utility commissions have established pipeline infrastructure replacement programs as part of the ratemaking process. These programs play a vital role in protecting the public by ensuring the prompt rehabilitation, repair, or replacement of high-risk gas distribution infrastructure.

Several state public utility commissions, including those in New Jersey, Kentucky, and Indiana, have used their traditional ratemaking authority to approve such programs. Other States, like Missouri, Kansas, and Nebraska, have provided their public utility commissions with specific statutory authority to approve pipeline infrastructure replacement programs based on detailed eligibility requirements and cost-recovery formulas. Ohio has a statute in place that provides its commission with far more flexibility and discretion. California recently enacted a statutory scheme requiring the implementation of a comprehensive program for pressure testing and replacement of gas pipelines.

Whether as part of the traditional ratemaking process or in a separate proceeding, PHMSA urges State public utility commissions to accelerate the repair, rehabilitation, and replacement of high-risk pipeline infrastructure. The recent pipeline accidents in San Bruno, Philadelphia, and Allentown show the tremendous cost in terms of fatalities, injuries, and property damage that can result in the absence of such action.

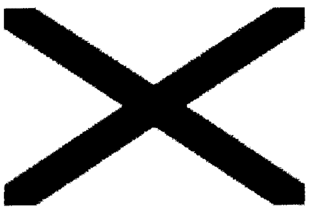
PHMSA is focused on this issue in implementing its integrity management requirements for natural gas transmission and distribution lines and as part of the state certification process. PHMSA is willing to provide assistance to State public utility commissions who are seeking to establish or improve programs for the repair, rehabilitation, and replacement of high risk pipeline infrastructure. Such assistance could include offering testimony at legislative hearings or in state proceedings, providing technical expertise in identifying high-risk pipeline infrastructure, and ensuring that state pipeline safety regulators are effectively implementing the integrity management requirements for natural gas transmission and distribution lines.

Appendix I:

Additional Information on State Pipeline Infrastructure Replacement Programs

Hyperlinks Confirmed as of Date of Publication and Available for Use in Electronic Version Only

Alabama



STATE AUTHORITY: Alabama Public Service Commission

PROGRAM: Rate Stabilization and Equalization Plan

PARTICIPANTS: Mobile Gas

Alabama Gas

Arkansas

STATE AUTHORITY: Arkansas Public Service Commission

PROGRAM: Main Replacement Program Rider

PARTICIPANTS: CenterPoint Energy

California

STATE AUTHORITY: California Public Utilities Commission

PROGRAM: Comprehensive Implementation Plan

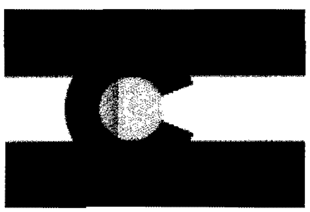
PARTICIPANT: San Diego Gas and Electric

PROGRAM: Pipeline Safety Enhancement Plan

PARTICIPANTS: Southern California Gas

Pacific Gas & Electric

Colorado

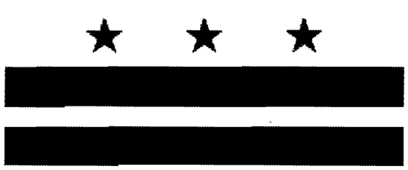


STATE AUTHORITY: Colorado Public Service Commission

PROGRAM: Pending

PARTICIPANT: Colorado Public Service Company

District of Columbia

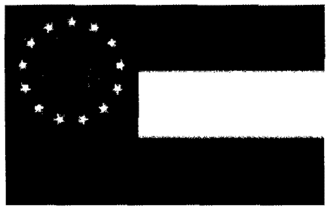


STATE AUTHORITY: District of Columbia Public Service Commission

PROGRAM: Pending

PARTICIPANT: Washington Gas

Georgia



STATE AUTHORITY: Georgia Public Service Commission

PROGRAM: Pipeline Replacement Program

PARTICIPANT: Atlanta Gas Light

PROGRAM: Pipeline Replacement Surcharge

PARTICIPANT: Atmos Energy

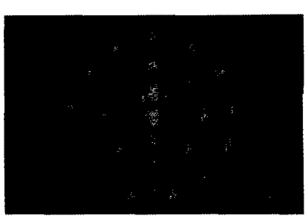
Illinois

STATE AUTHORITY: Illinois Commerce Commission

PROGRAM: Infrastructure Cost Recovery Rider

PARTICIPANT: Integrys Peoples Gas

Indiana



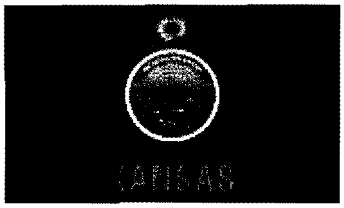
STATE AUTHORITY: Indiana Utility Regulatory Commission, Gas Division

PROGRAM: Pipeline Safety Adjustment

PARTICIPANT: Vectren Energy Delivery of Indiana, Inc.

Vectren South – SICEGO

Kansas



STATE AUTHORITY: Kansas Corporation Commission

PROGRAM: Accelerated Pipeline Replacement Rider

PARTICIPANT: Black Hills Energy

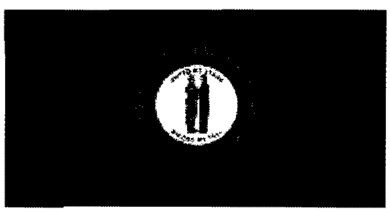
PROGRAM: Gas System Reliability Surcharge Rider

PARTICIPANT: Kansas Gas Service

Atmos Energy

LAWS: Gas Safety and Reliability Policy Act

Kentucky



STATE AUTHORITY: Kentucky Public Service Commission

PROGRAM: Accelerated Main Replacement Program Rider

PARTICIPANT: Columbia Gas Kentucky

PROGRAM: Pipeline Replacement Program

PARTICIPANT: Delta Natural Gas

PROGRAM: Accelerated Main Replacement Program

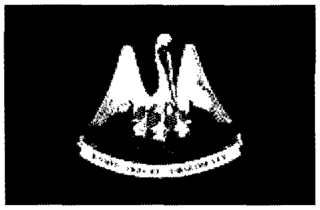
PARTICIPANT: Duke Energy Kentucky

PROGRAM: Pipeline Replacement Program Rider

PARTICIPANT: Atmos Energy

LAWS: KRS 278.509

Louisiana



STATE AUTHORITY: Louisiana Public Service Commission

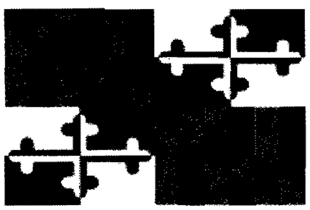
PROGRAM: Rate Stabilization Tariffs

PARTICIPANTS: Atmos Energy – LA

Entergy

CenterPoint Energy

Maryland



STATE AUTHORITY: Maryland Public Service Commission

PROGRAM: Pending

PARTICIPANTS: Washington Gas

Massachusetts

STATE AUTHORITY: Massachusetts Department of Public Utilities, Pipeline Engineering and Safety Division

PROGRAM: Targeted Infrastructure Reinvestment Factor

PARTICIPANTS: Columbia Gas Massachusetts

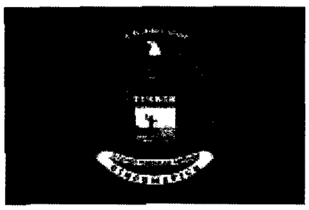
National Grid Massachusetts

New England Gas

PROGRAM: Pending

PARTICIPATNT: Fitchburg Gas and Electric

Michigan

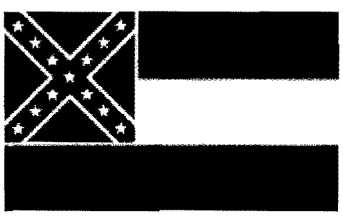


STATE AUTHORITY: Michigan Public Service Commission

PROGRAM: Main Replacement Program Rider

PARTICIPANT: SEMCO Energy

Mississippi



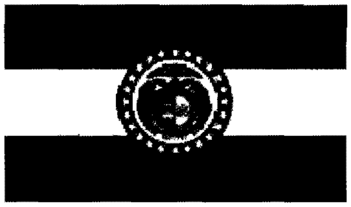
STATE AUTHORITY: Mississippi Public Service Commission

PROGRAM: Rate Stabilization Tariffs

PARTICIPANTS: Atmos Energy – MS

CenterPoint Energy

Missouri



STATE AUTHORITY: Missouri Public Service Commission

PROGRAM: Infrastructure System Replacement Surcharge

PARTICIPANTS: Ameren Missouri

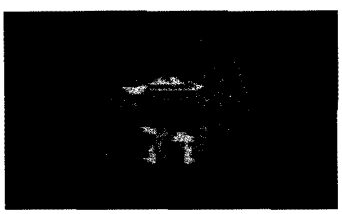
Laclede Gas

Missouri Gas Energy

Atmos Energy - MO

LAWS: MO ST 393.1009 *et seq.*

Nebraska



STATE AUTHORITY: Nebraska Public Service Commission

PROGRAM: Infrastructure System Replacement Cost Recovery Charge

PARTICIPANT: Black Hills Energy

LAWS: NE ST 66-1865

NE ST 66-1866

NE ST 66-1867

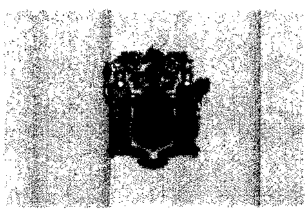
New Hampshire

STATE AUTHORITY: New Hampshire Public Utilities Commission

PROGRAM: Cast Iron Bare Steel Replacement Program

PARTICIPANT: National Grid Energy North

New Jersey



STATE AUTHORITY: New Jersey Board of Public Utilities

PROGRAM: Utility Enhancement Infrastructure Rider

PARTICIPANT: Elizabethtown Gas

PROGRAM: Accelerated Infrastructure Investment Program

PARTICIPANT: New Jersey Natural Gas

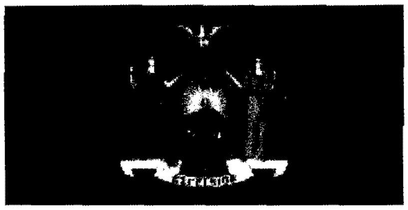
PROGRAM: Capital Adjustment Charge

PARTICIPANT: Public Service Electric and Gas

PROGRAM: Capital Investment Recovery Tracker

PARTICIPANT: South Jersey Gas

New York

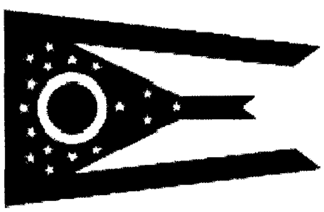


STATE AUTHORITY: New York State Public Service Commission

PROGRAM: LIMITED INFRASTRUCTURE REPLACEMENT

PARTICIPANTS: National Grid Long Island, Niagara Mohawk, and NYC
Corning Natural Gas

Ohio



STATE AUTHORITY: Ohio Public Utility Commission

PROGRAM: Infrastructure Replacement Program

PARTICIPANTS: Columbia Gas Ohio

PROGRAM: Pipeline Infrastructure Replacement Cost Recovery Charge

PARTICIPANT: Dominion East Ohio

PROGRAM: Accelerated Main Replacement Program Rider

PARTICIPANT: Duke Energy Ohio

PROGRAM: Distribution Replacement Rider

PARTICIPANT: Vectren Energy Delivery of Ohio, Inc.

Oklahoma

STATE AUTHORITY: Oklahoma Corporation Commission

PROGRAM: Rate Stabilization Tariffs

PARTICIPANTS: Oklahoma Natural Gas

CenterPoint Energy

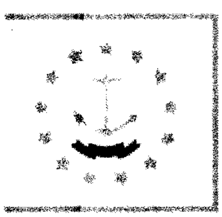
Oregon

STATE AUTHORITY: Oregon Public Utility Commission

PROGRAM: Replacement Projects

PARTICIPANT: Avista Corp

Rhode Island

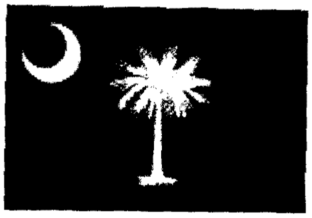


STATE AUTHORITY: Rhode Island Public Utilities Commission

PROGRAM: Capital Expenditure Tracker Factor, Accelerated Replacement Program

PARTICIPANT: National Grid Narragansett Gas

South Carolina



STATE AUTHORITY: South Carolina Office of Regulatory Staff

PROGRAM: Rate Stabilization Tariff

PARTICIPANTS: Piedmont Natural Gas

South Carolina Electric and Gas

Texas

STATE AUTHORITY: Texas Railroad Commission

PROGRAM: Gas Reliability Infrastructure Program

PARTICIPANTS: CenterPoint Energy

Atmos Energy – TX

Texas Gas Service

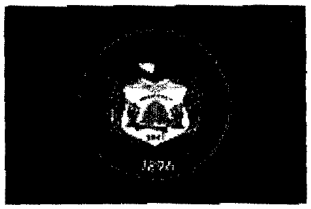
PROGRAM: Rate Stabilization Tariffs

PARTICIPANTS: Atmos Energy – TX

CenterPoint Energy

LAWS: Tex. Util.Code § 104.301

Utah

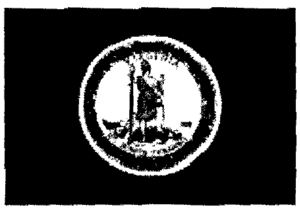


STATE AUTHORITY: Utah Public Service Commission

PROGRAM: Infrastructure Rate Adjustment Tracker

PARTICIPANT: Questar Gas

Virginia



STATE AUTHORITY: Virginia State Corporation Commission

PROGRAM: Pending

PARTICIPANT: Washington Gas

LAWS: SAVE Act

American Gas Association SOS
Performance Metrics

Background: Northern States Power Company, a Minnesota corporation (NSPM) d/b/a Xcel Energy has a Gas Utility Infrastructure Cost (GUIC) Rider to recover Transmission and Distribution Integrity Management Program (TIMP and DIMP) costs. Xcel Energy is gathering information on gas utility integrity management programs in order to identify possible opportunities to leverage best practices in the development of performance metrics related to program expenditures. Xcel Energy is involved in a stakeholder process to develop metrics to measure the appropriateness of expenditures. NSPM seeks information through the AGA SOS process to determine what performance metrics other companies have implemented to track the efficiency or appropriateness of TIMP and DIMP expenditures.

Process: The following is requested by AGA on behalf or for the benefit of AGA members. Any resulting aggregation of the collected data may be shared with a stakeholder process convened to develop metrics to measure the appropriateness of expenditures by the AGA member. The stakeholder group consists of members from the Minnesota Public Utilities Commission Staff, Minnesota Department of Commerce, Minnesota Office of Attorney General-Residential Utilities Division, and Minnesota Office of Pipeline Safety. A summary of the information may also be included in a regulatory filing submitted to the Minnesota Public Utilities Commission. Any resulting aggregation and distribution of the collected data will also be through the member restricted side of the AGA website. Once the data is collected, respondents will receive an email from AGA with a link to the posted data. <u>Members who wish their responses to be anonymous should indicate so in their response</u>.

1. Please provide your contact information. *

   Company Name: ____

   Contact Name: ____

   Email: ____

2. Does your Company have a cost recovery mechanism to recover TIMP and/or DIMP costs outside of base rates?

   ______Yes

   ______ No

   If yes, please describe your Company's cost recovery mechanism including the docket number(s) and enabling statute or regulation/rule.

   ____

   ____

   ____

   ____

3. Has your Company developed performance metrics to evaluate the effectiveness of your TIMP and DIMP investments? If so, please describe.

   ____

   ____

   ____

   ____

4. What process did you use to develop the metrics?

   ____

   ____

   ____

   ____

5. Do the metrics change over time based on the type of investments being made?

   ____

   ____

   ____

   ____

6. How, if at all, are metric results incorporated into TIMP/DIMP investment decisions made by the Company?

   ____

   ____

   ____

   ____

7. Are there any incentives or forfeitures that are triggered by outcomes of the performance metrics? If so, please describe.

____
____
____
____

8. Have you experienced any cost savings, such as O&M costs, associated with DIMP and/or TIMP investments, and are you required to account for those savings in your cost recovery mechanism?

____
____
____
____

9. Have you generated any learnings from your metrics?

____
____
____
____

10. * AGA is collecting and compiling responses to this survey. Do you wish your responses to remain anonymous when a survey summary is posted on the members-only side of the AGA website? Please type YES or NO.

____

11. Would you be willing to be contacted by a representative from the requesting company to discuss your responses to this survey in greater detail? If yes, please provide the name and email address for your subject matter expert. *Note: This information will be removed before a summary of responses to this survey is posted to the members only side of AGA.org*.

Name: ____

Phone Number: ____

Email Address: ____

DUE: May 1, 2016

For Calendar Year 2015

DOCKET # 16-4

	Trade Secret
X	Public

MINNESOTA DEPARTMENT OF COMMERCE

Minnesota Department of Commerce
GAS JURISDICTIONAL ANNUAL REPORT

COMPANY INFO U # 10735 FEIN# 41-1967505

Name	Northern States Power Company
Web Site	xcelenergy.com
Contact	Anne E. Heuer, Director, Revenue Analysis
Address	414 Nicollet Mall, 401-07
City State Zip	Minneapolis, MN 55401

Annual Report Contact Information

Contact Name	Anne E. Heuer, Director, Revenue Analysis
E-Mail Address	anne.e.heuer@xcelenergy.com
Phone #	612-330-6181

NEW FILING INFORMATION

Please return this completed form in .xls format only via the DOC/PUC Efiling system
https://www.edockets.state.mn.us/EFiling/home.jsp

Please efile a separate document with this report for additional information or worksheet if need.

If Trade Secret information is included, you must file a complete PUBLIC and TRADE SECRET Report

GAS-INDEX

MINNESOTA DEPARTMENT OF COMMERCE

Company: Northern States Power Company

(Minnesota Gas Jurisdiction)
For Calendar Year 2015

Page G-1

Minnesota Department of Commerce

GENERAL INFORMATION (Gas Operation Only)

Are your MN Gas tariffs on your website? Yes

Web site Address. xcelenergy.com

Location of office in which accounts and records are maintained. 414 Nicollet Mall, 401-7
Minneapolis, MN 55401

Name, title, address, email and telephone number of the utility officer to whom correspondence concerning this report should addressed:

Anne E. Heuer, Phone: (612) 330-6181
414 Nicollet Mall
Minneapolis, MN 55401

Important Changes

List significant changes which occurred during current filing period.

NUMBER OF EMPLOYEES

	Current Year	Previous Year
*Total Regular Employees	3,623	3,778
*Total Part-Time & Temporary Employees	11	15

Assessable Operating Revenues

Total Minnesota Jurisdictional Sales to Ultimate Consumers	484,158
Less: Gross Earning Tax (if it is included in the Total Sales reported above)	
Total Minnesota Jurisdictional assessable Operating Revenue	484,158

*The number of employees as reported in the 10k annual report.

Company Northern States Power Company (Minnesota Gas Jurisdiction) Page G-2
For Calendar Year 2015

MINNESOTA DEPARTMENT OF COMMERCE

NARUC DATA WORKSHEET

COMPOSITE STATISTICS FOR ALL **PRIVATELY OWNED GAS UTILITIES**
(Under Agency Jurisdiction)

Plant (Intrastate Only) (000 Omitted)	$		
Plant in Service	$	1,164,217	
Construction Work In Progress	$	15,130	
Plant Acquisition Adjustment	$		
Plant Held For Future Use	$		
Materials and Supplies	$	34,276	
Less:			
Depreciation and Amortization Reserves	$	547,140	
Contributions in Aid of Construction	$		
NET BOOK COSTS		666,483	
Revenues and Expenses (Intrastate Only) (000 Omitted)			
Operating Revenues	$	487,955	*
Depreciation and Amortization Expenses	$	45,585	
Income Taxes	$	13,022	*
Other Taxes	$	19,802	
Other Operating Expenses	$	378,858	
Total Operating Expenses	$	457,267	*
Net Operating Income		30,688	*
Other Income	$	987	
Other Deductions	$		
NET INCOME	$	31,676	*
Customers (Intrastate Only)			
Year-End Average:			
Residential		413,101	
Commercial		34,404	
Industrial		410	
Others		19	
Total Number of Customers		447,933	
Other Statistics (Intrastate Only)			
Average Annual Residential Use - (MCF)		81	
Average Residential Cost Per Mcf ($)	$	8.28	
Average Residential Monthly Bill	$	55.89	
Gross Plant Investment per Customer	$	2,818	

* Including CIP Incentives in Jurisdictional Earnings would result in the following line changes:

Operating Revenue	487,443
Income Taxes	15,341
Total Operating Expenses	453,469
Net Operating Income	33,974
Net Income	34,962

Company Northern States Power Company (Minnesota Gas Jurisdiction) Page G-3

For Calendar Year 2015

MINNESOTA DEPARTMENT OF COMMERCE

IDENTITY OF RESPONDENT

1. Exact name of respondent. Use the words "The" and "Company" or "Co." only when they are part of the corporate name.
   Northern States Power Company (hereafter "NSP")

2. Respondent Information:

Contact Name/Title	Anne E. Heuer, Director, Revenue Requirements North
Address	414 Nicollet Mall, 401-7
City , State, Zip	Minneapolis, MN 55401
Phone number	612-330-6181
E-mail Address	anne.e.heuer@xcelenergy.com
Web Site	www.xcelenergy.com

3. Date of incorporation. March 8, 2000; renamed Northern States Power Company on August 21, 2000

4. Laws affecting organization. If incorporated under a special charter, give date of passage of the act; if under a general law, give date of filing certificate of organization; if a reorganization has been effected, give date of reorganization. If a receivership or other trust, give also date when such receivership or other possession began. If a partnership, give date of formation, and names of present partners. Give specific reference to applicable laws of the State or Territory under which organized, citing chapter and section of each statute and all amendments thereof. Include all grants of corporate powers by the United States or any foreign country; also, all amendments to charter.

Northern States Power Company, a Minnesota corporation, was incorporated in the State of Minnesota pursuant to Minn. Stat. Chapter 302A as Northern States Power Company on March 8, 2000.

5. Consolidated or merged companies. Indicate the name of each company consolidated, merged, or otherwise combined with the respondent during the year, associating therewith specific reference (citing chapter and section) to special or general laws, including all amendments, under which each consolidation, merger, or other combination was affected; and, when applicable, the name of the governmental body authorizing the combination and specific reference to the instrument of authorization. In each case, give the date that the combination was affected. Also, give specific reference (citing chapter and section) to provisions of the charter or the laws, including all amendments, governing the organization (or reorganization) of each constituent or merged company. Cases in which corporations have become inactive and have been practically absorbed through ownership or control of their entire capital stock, through leases of long duration (under which the lessor companies do not maintain independent organizations for financial purposes), or otherwise, so that no distinction is made in operating or in accounting by reason of the original separate incorporation, should be included in a separate list and fully explained.

Not Applicable. NSP did not consolidate, merge, or otherwise combine with any company during the year.

6. Former identity. If, because of reorganization during the year or for any other reason the respondent conducted any part of its business under a name or names other than that shown under item 1 above, give the name or names under which such business was conducted. Also state the circumstances occasioning the reorganization.

NSP also conducts business in Minnesota under the trade name "Xcel Energy".

Company Northern States Power Company

(Minnesota Gas Jurisdiction)

For Calendar Year 2015

CONTROL OVER RESPONDENT

1 If direct control over the respondent was held by a corporation, individual, association or other person at the end of the year, state:

a. The form of control (sole or joint):

Xcel Energy Inc. owns 100% of the issued common stock shares (1,000,000 shares, par value $0.01) of NSP.

b. The name and address of the directly controlling organization or person:
(Give names and address of all organizations or persons involved if control was joint.)

Xcel Energy Inc.
414 Nicollet Mall
Minneapolis, MN 55401

c. The means by which control was held:
(For example, through ownership of voting securities; through common directors, officers or stockholders; through voting trusts; etc.).

Xcel Energy Inc. owns 100% of the voting securities of NSP. The Board of Directors of NSP is comprised of officers of Xcel Energy Inc. The
officers of NSP are officers or management employees of Xcel Energy Services Inc., the service company in Xcel Energy Inc. holding
company system.

d. The extent of control:

Xcel Energy Inc. owns 100% of the issued common stock shares (1,000,000 shares, par value $0.01) of NSP.

2 If the directly controlling organization or person named in query 1(b), above, was in turn controlled by another organization or person, the respondent shall show hereunder the chain of control to the ultimately controlling organization or person and the extent of control over each directly controlled organization or person in the chain.

Not Applicable. The securities of Xcel Energy Inc. are publicly traded.

3 If any controlling organization or person named in response to query 1(b), above held control as trustee, give, if known, the name and address of the beneficiary (or beneficiaries) for whom the trust is maintained, and the purpose of the trust.

Not Applicable.

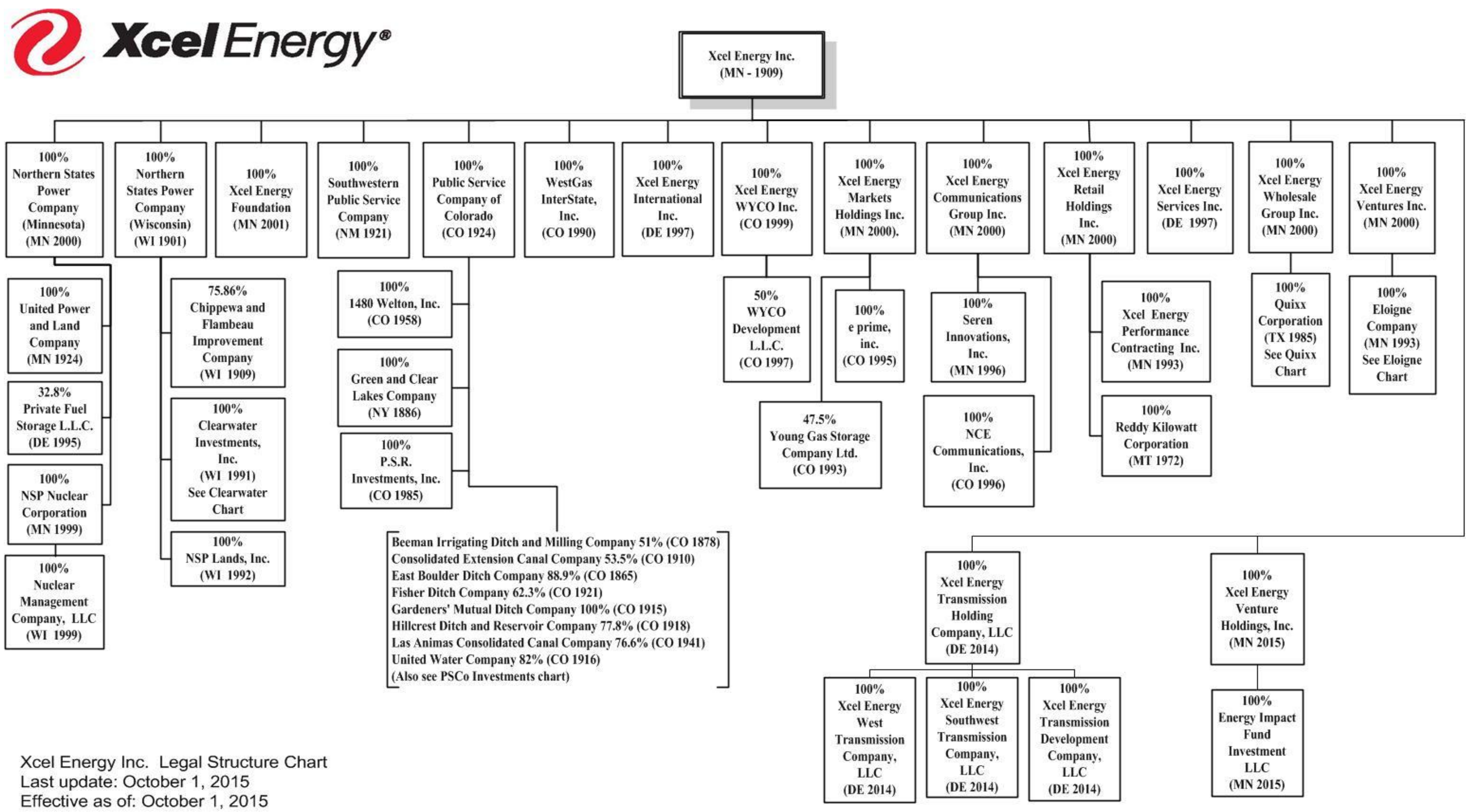
Company Xcel Energy Inc.

(Minnesota Gas Jurisdiction)
For Calendar Year 2015

MINNESOTA DEPARTMENT OF COMMERCE

ORGANIZATION CHART

1. For gas companies with operations that are part of a holding company's operations, provide a complete organization chart of all of the holding company's regulated and non-regulated operations.



Xcel Energy Inc. Legal Structure Chart
Last update: October 1, 2015
Effective as of: October 1, 2015

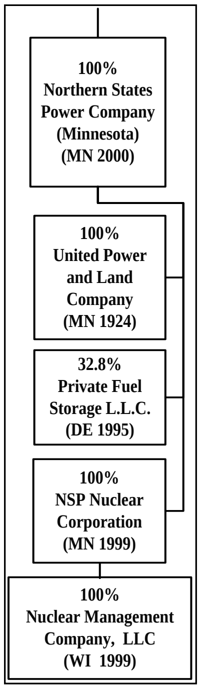
Company Northern States Power Company

(Minnesota Gas Jurisdiction)
For Calendar Year 2015

MINNESOTA DEPARTMENT OF COMMERCE

ORGANIZATION CHART

1. For gas companies with operations that are part of a holding company's operations, provide a complete organization chart of all of the holding company's regulated and non-regulated operations.



Company Xcel Energy Inc.

(Minnesota Gas Jurisdiction)

For Calendar Year 2015

Minnesota Department of Commerce

BOARD OF DIRECTORS

Give the name of each person who was a member of the board of directors at any time during the year, indicating with an asterisk (*) in column (a) those directors who were members of the Executive Committee (if any), and by a double asterisk (**) the chairman, if any, of that committee, at the end of the year. Columns (e) and (f) relate to Board meetings only.

Ref. to Line	Exec. Comm. (a)	Name of Director and Address (City and State) (b)	Served Continuously From (c)	To (d)	Term Expired or Current Term Will Expire (e)	# of Meetings Attended DuringYear (f)	Fees Paid No. During Year
1	n/a	Gail Koziara Boudreaux	2012	present	5/18/16	6	250,973
2	n/a	Richard K. Davis	2006	present	5/18/16	6	243,315
3	n/a	Benjamin G. S. Fowke III	2009	present	5/18/16	6	0
4	n/a	Albert F. Moreno	1999	present	5/18/16	6	228,315
5	n/a	Richard T. O'Brien	2012	present	5/18/16	6	246,978
6	n/a	Christopher J. Policinski	2009	present	5/18/16	6	252,978
7	n/a	James T. Prokopanko	2015	present	5/18/16	3	145,792
8	n/a	A. Patricia Sampson	1985	present	5/18/16	6	228,315
9	n/a	James J. Sheppard	2011	present	5/18/16	5	218,315
10	n/a	David A. Westerlund	2007	present	5/18/16	6	234,978
11	n/a	Kim Williams	2009	present	5/18/16	6	258,978
12	n/a	Timothy V. Wolf	2007	present	5/18/16	6	239,144
13							
14							
15							

16 Name of Chairman of the Board: Benjamin G.S. Fowke III

17 Name of Secretary (or clerk) of Board: Judy M. Poferl

18 Number of meetings of Board during the year: 6

19 Number of directors provided for by charter or by-laws, as amended to the end of the year: At least 7, no more than 15

20 Number of directors required to constitute a quorum: Majority

21 State briefly the powers and duties of Executive Committee (if any)

Company Northern States Power Company

(Minnesota Gas Jurisdiction)

MINNESOTA DEPARTMENT OF COMMERCE

BOARD OF DIRECTORS

For Calendar Year 2015

Give the name of each person who was a member of the board of directors at any time during the year, indicating with an asterisk (*) in column (a) those directors who were members of the Executive Committee (if any), and by a double asterisk (**) the chairman, if any, of that committee, at the end of the year. Columns (e) and (f) relate to Board meetings only.

Ref. to Line	Exec. Comm. (a)	Name of Director and Address (City and State) (b)	Served Continuously From (c)	To (d)	Term Expired or Current Term Will Expire (e)	# of Meetings Attended DuringYear (f)	Fees Paid No. During Year
1	n/a	Benjamin G.S. Fowke III	2005	present	2016	4	0
2	n/a	Teresa S. Madden	2011	present	2016	4	0
3	n/a	Christopher B. Clark	2015	present	2016	4	0
4	n/a	Marvin E. McDaniel, Jr.	2015	present	2016	4	0
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							

16	Name of Chairman of the Board	Benjamin G.S. Fowke III
17	Name of Secretary (or clerk) of Board	Judy M. Poferl
18	Number of meetings of Board during the year	4
19	Number of directors provided for by charter or by-laws, as amended to the end of the year	one or more
20	Number of directors required to constitute a quorum	Majority

21 State briefly the powers and duties of Executive Committee (if any)

Company Xcel Energy Inc.

(Minnesota Gas Jurisdiction)
For Calendar Year 2015

PRINCIPAL GENERAL OFFICERS

1 The persons to be listed herein are the chairman of the board (if he/she is an officer as well as a director), president, vice-presidents, secretary, treasurer, general counsel, and comptroller. Respondents that do not have officers bearing the aforesaid titles shall list those officers who have the responsibilities normally associated with such titles.

2 Customary abbreviations may be used in showing titles and departments in columns (a) and (b).

Line No.	Title of General Officer (a)	Department Over Which Jurisdiction Is Exercised (b)	Name of Person Holding the Office at End of the Year (c)	Office Address (City and State) (d)
1	Chairman, President and CEO		Benjamin G.S. Fowke III	414 Nicollet Mall, Minneapolis, MN
2	Senior VP and General Counsel		Scott M. Wilensky	414 Nicollet Mall, Minneapolis, MN
3	VP and Secretary		Judy M. Poferl	414 Nicollet Mall, Minneapolis, MN
4	Senior VP and CFO		Teresa S. Madden	414 Nicollet Mall, Minneapolis, MN
5	Senior VP and CAO		Marvin E. McDaniel, Jr.	414 Nicollet Mall, Minneapolis, MN
6	VP and Controller		Jeffrey S. Savage	414 Nicollet Mall, Minneapolis, MN
7	VP and Treasurer		Brian J. Van Abel	414 Nicollet Mall, Minneapolis, MN
8				
9				
10				
11				
12				
13				
14				
15				

Company Northern States Power Company

(Minnesota Gas Jurisdiction)

PRINCIPAL GENERAL OFFICERS

For Calendar Year 2015

1 The persons to be listed herein are the chairman of the board (if he/she is an officer as well as a director), president, vice-presidents, secretary, treasurer, general counsel, and comptroller. Respondents that do not have officers bearing the aforesaid titles shall list those officers who have the responsibilities normally associated with such titles.

2 Customary abbreviations may be used in showing titles and departments in columns (a) and (b).

Line No.	Title of General Officer (a)	Department Over Which Jurisdiction Is Exercised (b)	Name of Person Holding the Office at End of the Year (c)	Office Address (City and State) (d)
1	Chairman, CEO		Benjamin G.S. Fowke III	414 Nicollet Mall, Minneapolis, MN
2	President		Christopher B. Clark	414 Nicollet Mall, Minneapolis, MN
3	Senior VP and CFO		Teresa S. Madden	414 Nicollet Mall, Minneapolis, MN
4	Senior VP and General Counsel		Scott M. Wilensky	414 Nicollet Mall, Minneapolis, MN
5	Senior VP		Marvin E. McDaniel, Jr.	414 Nicollet Mall, Minneapolis, MN
7	Senior VP		Kent T. Larson	414 Nicollet Mall, Minneapolis, MN
8	Senior VP and Chief Nuclear Officer		Timothy J. O'Connor	414 Nicollet Mall, Minneapolis, MN
9	VP and Secretary		Judy M. Poferl	414 Nicollet Mall, Minneapolis, MN
10	VP and Treasurer		Brian J. Van Abel	414 Nicollet Mall, Minneapolis, MN
11	VP and Controller		Jeffrey S. Savage	414 Nicollet Mall, Minneapolis, MN
11				
12				
13				
14				
15				

Company Xcel Energy Inc.

(Minnesota Gas Jurisdiction)
For Calendar Year 2015

MINNESOTA DEPARTMENT OF COMMERCE

VOTING POWERS AND ELECTIONS

		YES	NO
1	Has each share of stock the right to one vote?	X	
2	Are voting rights attached only to stock? *(If the answer to either query 1 or 2 is "No," give full particulars in a note.)*	X	
3	Is cumulative voting permitted?	X	

4 The date and place of the latest general meeting for the election of directors was 5/20/15 at 201 East 8th Street, Sioux Falls, SD

5 The voting power of all stockholders of the respondent on 3/24/2015, the date of the latest compilation was 506,659,988 votes.

6 The total number of shares voted at the meeting on the date shown in the answer to query 4 was 424,615,698 shares.

7 The number of shares voted by proxies at the meeting on the date shown in answer to query 4 was . 424,615,698 shares

8 If any security has preferences, special privileges, or restrictions in the election of directors, trustees, or managers, or in the determination of any corporate action, give details.

Company Northern States Power Company

(Minnesota Gas Jurisdiction)
For Calendar Year 2015

MINNESOTA DEPARTMENT OF COMMERCE

VOTING POWERS AND ELECTIONS

		YES	NO
1	Has each share of stock the right to one vote?	X	
2	Are voting rights attached only to stock?	X	
	(If the answer to either query 1 or 2 is "No," give full particulars in a note.)		
3	Is cumulative voting permitted?		X

4 The date and place of the latest general meeting for the election of directors was 4/2/15 at 414 Nicollet Mall, Minneapolis, MN

5 The voting power of all stockholders of the respondent on 1,000,000 , the date of the latest compilation was 1,000,000 votes.

6 The total number of shares voted at the meeting on the date shown in the answer to query 4 was 1,000,000 shares.

7 The number of shares voted by proxies at the meeting on the date shown in answer to query 4 was . 1,000,000 shares

8 If any security has preferences, special privileges, or restrictions in the election of directors, trustees, or managers, or in the determination of any corporate action, give details.

Company Xcel Energy Inc.

(Minnesota Gas Jurisdiction)
For Calendar Year 2015

STOCKHOLDERS

1. This information shall be compiled as at December 31, except that if similar information has been compiled for some other purpose between the beginning of the year for which the report is made and the date of preparation of this report, the latest compilation shall be used.

2. Stockholders of each class of stock shall be listed in the order of their holdings, beginning with the highest and continuing until the 25 largest holdings have been listed. If any such holder was a trustee or nominee for other persons who held the beneficial interest in the securities, the name and address of each person who has the beneficial interest shall be shown in a note, if known. Likewise, if any person had the beneficial interest in securities held by trustees or nominees under different trusts or other groupings, and the aggregate of such person's holdings would place him among the listed holders if he were the holder of record, the details of such holdings shall be shown in a note, if known.

Line No.	Class of Stock	Stockholder Name	Stockholder Address (City and State)	Shares Held
1	Common	BENJAMIN G S FOWKE III	75 CLAY CLIFFE DR, EXCELSIOR MN 55331-9510	402,845
2	Common	WAYNE H BRUNETTI & MARY K BRUNETTI JT TEN	PO BOX 2007, SILVERTHORNE CO 80498-2007	362,433
3	Common	OCONNELL FAMILY LTD PARTNERSHIP	245 STARRWOOD, HUDSON WI 54016-7174	165,910
4	Common	CYNTHIA L LESHER	1121 BLACK OAK DR, NEW BRIGHTON MN 55112-8400	146,381
5	Common	HART SECURITIES LTD C/O JEFFREY M TRINKLEIN GIBSON DUNN & CRUTCHER	1050 CONNECTICUT AVE NW, WASHINGTON DC 20036-5303	131,000
6	Common	TERESA S MADDEN	5654 CASCADE PL, BOULDER CO 80303-2950	103,076
7	Common	SCOTT WILENSKY	1120 S 2ND ST APT 911, MINNEAPOLIS MN 55415-1398	79,773
8	Common	MARVIN E MCDANIEL	2454 CASTLE BUTTE DR, CASTLE ROCK CO 80109-9570	73,861
9	Common	GEORGE E TYSON II	7414 MOCCASIN TRL, CHANHASSEN MN 55317-7551	69,702
10	Common	MARK E STOERING	18309 TRISTRAM WAY, EDEN PRAIRIE MN 55346-1135	63,172
11	Common	DAVID M WILKS	3966 PINEDALE CT, HIGHLANDS RANCH CO 80126-5043	62,446
12	Common	DAVID L EVES	52 BROOKHAVEN LN, LITTLETON CO 80123-6685	54,762
13	Common	KENT TAYLOR LARSON	1034 SHERWOOD RD, SHOREVIEW MN 55126-8429	49,527
14	Common	EMMA A CARBONE TOD ROBERT G CARBONE SUBJECT TO STA TOD RULES	1270 EARL ST, SAINT PAUL MN 55106-2025	41,599

Total holders of above class of stock 1,806,487

Date of above compilation 4/20/16

(continued on next page)

Company Xcel Energy Inc.

(Minnesota Jurisdiction)
For Calendar Year 2015

STOCKHOLDERS (continued)

Line No.	Class of Stock	Stockholder Name	Stockholder Address (City and State)	Shares Held
15	Common	ALFRED A ZWANENBURG & THEODORA H ZWANENBURG TR UA DTD 3/7/95 ZWANENBURG FAM LIVING TRUST	2631 BRIAR PATCH LN, FLOWER MOUND TX 75022-6008	40,312
16	Common	W THOMAS STEPHENS	3333 E PLATTE AVE, GREENWOOD VILLAGE CO 80121-1949	34,222
17	Common	FRANK P PRAGER	11652 E BERRY AVE, ENGLEWOOD CO 80111-4155	34,216
18	Common	GLADYS P WILKS & DAVID M WILKS JT TEN	3966 PINEDALE CT, HIGHLANDS RANCH CO 80126-5043	33,437
19	Common	DARLA FIGOLI	6245 E 167TH AVE, BRIGHTON CO 80602-6066	30,546
20	Common	JACK S DYBALSKI	3408 SUNNYSIDE CT, NAPERVILLE IL 60564-9002	30,316
21	Common	JAMES DI PASQUALE	PO BOX 23084, SAN ANTONIO TX 78223-0084	30,000
22	Common	CHARLES RUBENSTEIN	6085 LINCOLN DR APT 123, EDINA MN 55436-1632	30,000
23	Common	PETER J FURSTENBERG TR UA 09/01/05 CARL A HERBST JR RESIDUAL TRUST	6420 E BERRY AVE, GREENWOOD VILLAGE CO 80111-1508	29,954
24	Common	CARL A BACHMEIER JR	PO BOX 384, KEARNY NJ 07032-0384	29,755
25	Common	JAMES PHILLIP DIPASQUALE	PO BOX 23084, SAN ANTONIO TX 78223-0084	28,000

Total holders of above class of stock 350,758

Date of above compilation 4/20/16

Company Northern States Power Company

MINNESOTA DEPARTMENT OF COMMERCE

(Minnesota Gas Jurisdiction)
For Calendar Year 2015

IMPORTANT CHANGES DURING THE YEAR

Give concise answers to each of the following, numbering them in accordance with the numbers of the queries

1 List extensions of system (other than additions supplementing existing facilities of the respondent) whether by purchase, construction, donation, or otherwise. Give the location, new territory covered, and dates of beginning operation, and in case of purchase give also the name and address of thecompany from which purchased, date of acquisition, and the consideration given.

None.

2 If during the year a substantial portion or all of the property of the respondent was sold, merged, or abandoned, give full particulars, including the location and territory covered. In case of sale or merger, give the effective date, name and address of successor company, and the consideration received.

None.

3 List important changes in service and rate schedules during the year, giving --

Estimated increase or decrease in annual revenues by reason of such changes,
Estimated saving or additional cost to the public, and
The basis used in arriving at the amounts given in the responses to (a) and (b).

NSP-Minnesota – Gas Utility Infrastructure Cost (GUIC) Rider — In October 2015, NSP-Minnesota filed the GUIC rider with the MPUC for approval to recover the cost of natural gas infrastructure investments in Minnesota to improve safety and reliability. Costs include funding for pipeline assessments as well as deferred costs from NSP-Minnesota's existing sewer separation and pipeline integrity management programs. Sewer separation costs stem from the inspection of sewer lines and the redirection of gas pipes in the event their paths are in conflict. NSP-Minnesota requested recovery of approximately $15.5 million from Minnesota gas utility customers beginning April 1, 2016. This request includes $1.9 million in over-recovery from 2015 and $4.5 million of deferred sewer separation and integrity management costs which is the 2016 portion of a five year amortization.

An MPUC decision is expected in the second half of 2016.

Company Northern States Power Company

(Minnesota Gas Jurisdiction)
For Calendar Year 2015

MINNESOTA DEPARTMENT OF COMMERCE

IMPORTANT CHANGES DURING THE YEAR

3 List important changes in service and rate schedules during the year, giving (continued)

CIP and CIP Rider — In December 2012, the MPUC approved reductions to the CIP financial incentive mechanisms effective for the 2013 through 2015 program years and in 2015 extended the mechanisms to the 2016 program year. The estimated average annual natural gas incentives are $3.6 million based on the approved savings goals.

CIP expenses are recovered through base rates and a rider that is adjusted annually.

- In July 2015, the MPUC approved NSP-Minnesota's 2014 CIP electric and natural gas financial incentives totaling $40.1 million and $5.8 million, respectively.
- In addition, the MPUC approved NSP-Minnesota's proposed 2015 to 2016 electric and natural gas CIP riders. NSP-Minnesota estimates 2016 recovery of $21.5 million of electric CIP expenses and $9.2 million of natural gas CIP expenses.
- This proposed recovery through the riders is in addition to an estimated $86.9 million and $3.7 million through electric and gas base rates, respectively.

Natural Gas Supply and Costs (Total Company - NSP Minnesota)

NSP-Minnesota actively seeks natural gas supply, transportation and storage alternatives to yield a diversified portfolio that provides increased flexibility, decreased interruption and financial risk and economical rates. In addition, NSP-Minnesota conducts natural gas price hedging activity that has been approved by the MPUC.

The following table summarizes the average delivered cost per MMBtu of natural gas purchased for resale by NSP-Minnesota's regulated retail natural gas distribution business:

2015	$4.07
2014	$6.17
2013	$4.53

The cost of natural gas in 2015 decreased due to lower wholesale commodity prices.

NSP-Minnesota has firm natural gas transportation contracts with several pipelines, which expire in various years from 2016 through 2033.

NSP-Minnesota has certain natural gas supply, transportation and storage agreements that include obligations for the purchase and/or delivery of specified volumes of natural gas or to make payments in lieu of delivery. At Dec. 31, 2015, NSP-Minnesota was committed to approximately $207 million in such obligations under these contracts.

NSP-Minnesota purchases firm natural gas supply utilizing long-term and short-term agreements from approximately 32 domestic and Canadian suppliers. This diversity of suppliers and contract lengths allows NSP-Minnesota to maintain competition from suppliers and minimize supply costs.

Company Northern States Power Company

(Minnesota Gas Jurisdiction)
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MINNESOTA DEPARTMENT OF COMMERCE

IMPORTANT CHANGES DURING THE YEAR

4 Give the names and addresses of all companies which during the year came under the direct control of the respondent otherwise than through title to securities, stating whether such control is sole or joint, how control was established, names of other parties to a joint agreement for control, the extent of control exercised by each party, and any other pertinent data requisite to a clear understanding of the arrangements relating to control. Where important details relating to control of a company have changed, give particulars. If during the year a company ceased to be controlled by the respondent, its nameand a statement of the fact will be sufficient.

None.

5 Give the names and addresses of all companies which during the year came under the indirect control of the respondent through non-reporting intermediaries, stating whether such control is sole or joint, how control was established, names of other parties to a joint agreement for control, the extent of control exercised by each party, the name and address of the intermediary through which the indirect control exists, and any other pertinentdata requisite to a clear understanding of the character of control. Where important details relating to control of a company have changed, give particulars. If during the year a company ceased to be controlled by the respondent, its name and a statement of the fact will be sufficient.

None.

6 Give a concise statement relative to each important contract, agreement, etc. entered into during the year (a) with pipelines, and, (b) with affiliated companies engaged in manufacturing, research, or similar activities. Exclude documents relating solely to services provided under effective tariffs. In lieu of giving abstracts from the contracts, agreements, etc., copies of such documents may be filed and a list of them given herein. If verified copies of such documents, and modifications thereof, have been filed with the Commission, a reference to that fact is sufficient.

As necessary, Administrative Service Agreements between Xcel Energy and its non-jurisdictional or non-regulated affiliates are filed with the MPUC for approval.

Company Northern States Power Company

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For Calendar Year 2015
(Minnesota Jurisdiction)

MINNESOTA DEPARTMENT OF COMMERCE

TRANSACTIONS WITH AFFILIATES ANNUAL REPORTING

Regulated Operating Companies	Provided For	Provided By
Administrative Agreement with Xcel Operating Subsidiaries (1)		
NSP Wisconsin	14,397,569	321,191
Public Service Co. of Colorado	191,919	132,907
Southwestern Public Service Co.	28,871	6,003
Hayden Joint Venture		
Sub-total Regulated Operating Companies	**14,618,359**	**460,100**
NSP Minnesota Agreements from Prior to Xcel Merger (2)		
NSP Wisconsin Interchange Agreement (3)	473,098,693	163,254,945
NSP Wisconsin SCADA Agreement (4)	45,433	-
Total Previously Existing Agreement Transaction	**473,144,127**	**163,254,945**
Total Regulated Operating Companies	**$ 487,762,486**	**$ 163,715,046**

NOTES:

(1) This section includes transactions directed by E002/AI-01-493 Compliance Filing only.
Beginning in 2005, totals include inventory transfers not previously available for reporting

(2) This section includes transactions which fall under agreements between NSPM and NSPW that NSPM was allowed to continue to operate under after the formation of Xcel Energy in August 2000.

(3) In accordance with FERC Docket No. ER15-1575-000, NSP and NSPW Interchange Agreement , the cost sharing of electric transmission and production costs for 2015

(4) NSP and NSPW SCADA and gas dispatch Agreement, Docket G-002/AI-94-831, regarding sharing of SCADA costs

(5) "Provided By" represents service provided by the affiliate/nonregulated to NSPM
"Provided For" represents service provided by NSPM to affiliate/nonregulated

Company Northern States Power Company

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	Provided For	Provided By
Parent Company		
Xcel Energy Services Inc.	715,118,392	1,142,313,010
Xcel Energy Inc.	9,942	88,163,876
Total Parent Company	**715,128,334**	**1,230,476,886**
Nonregulated Affiliates		
NSP Nuclear Corp.	140,000	90,000
United Power & Land Co.	-	-
Total Nonregulated Affiliates	**140,000**	**90,000**
Nonregulated Activity		
Homesmart	556,065	-
Non-Regulated Street Lighting Maintenance	22,173	-
Propane Gas	(1,055,362)	-
Sherco Steam to LPI	161,123	-
Other	8,633	-
Total Nonregulated Activity	**$ (307,367)**	**$ -**

NOTES:

(1) "Provided By" represents service provided by the affiliate/nonregulated to NSPM
"Provided For" represents service provided by NSPM to affiliate/nonregulated

Company Northern States Power Company Page G-12-3

For Calendar Year 2015
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MINNESOTA DEPARTMENT OF COMMERCE

TRANSACTIONS WITH AFFILIATES ANNUAL REPORTING *

Service Company Charges to NSPM Utility Operating Company for 2015

Functional Class	Indirect Charges	Direct Charges	Total
Administrative and General	$ 166,928,564	$ 43,011,765	$ 209,940,329
Customer Accounting	21,238,082	172,708	21,410,790
Customer Service and Information	769,673	2,131,095	2,900,769
Distribution	4,940,828	6,928,568	11,869,396
Gas Production		105,311	105,311
Gas Storage		51,806	51,806
Power Production	2,532,178	21,687,850	24,220,028
Regional Markets		314,475	314,475
Customer Sales		23	23
Transmission	7,050,243	12,307,197	19,357,440
Utility Plant		96,390,602	96,390,602
Non-Utility Plant		58,517	58,517
Receivable		-	-
Clearing		21,833,971	21,833,971
Regulatory Assets		16,427,015	16,427,015
Regulatory Liabilities		534,001	534,001
Taxes	4,158,429	3,374,448	7,532,878
Other Income	(44,211)	32,855	(11,355)
Other Income Deductions	1,063,826	210,761	1,274,587
Interest Charges	(65)	211,464	211,400
Other Power Supply	1,149,344	3,450,043	4,599,386
Gas Supply		333,992	333,992
Shared Asset Credit	-		
Grand Total	$ 209,786,892	$ 229,568,469	$ 439,355,360

* Information provided based on Company's FERC Form 1 filing, page 429.

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MINNESOTA DEPARTMENT OF COMMERCE

Administrative Services Agreement between Northern States Power Company and other Xcel Energy Inc.
Utility Operating Company Subsidiaries Reporting Requirements Stipulated in MPUC Docket No. E-002/AI-01-493

As a condition of approval of the Administrative Services Agreement ("Agreement") between Northern States Power Company d/b/a Xcel Energy ("Xcel Energy" or "the Company") and its utility operating company affiliates, MPUC Docket No. E-002/AI-01-493 (order dated June 22, 2001), Xcel Energy agreed to provide the following annual reporting recommended by the Department of Commerce. By order dated April 10, 2002, the Commission authorized the Company to provide the information contemporaneous with affiliate transaction portion of the May 1st jurisdictional financial report.

A Heading that identifies the type of transactions
The transactions included in the amounts shown on page E-13-1 are made up of costs associated with providing incidental services, lease arrangements, use of equipment, and other goods provided at cost by the Company to an operating company affiliate, or by the affiliate to the Company.

The identity of the affiliated parties in the first sentence
The other utility operating company parties to the Agreement are Northern States Power Company (Wisconsin) ("NSPW"), Public Service Company of Colorado ("PSCO") and Southwestern Public Service Company. Page E-13-1 lists the Xcel Energy affiliate included in the Agreement and the dollars charged to the affiliate by the Company or to the Company by the affiliate under the Agreement.

A general description of the nature and terms of the agreement, including the effective date of the contract or arrangement and the length of the contract or arrangement
The Agreement allows the operating utilities to share a limited amount of services, leasing arrangements, equipment, and other goods between them when it is mutually beneficial to the operating utilities involved. The Agreement allows these transactions to occur on an "at-cost" basis, consistent with U.S. Securities and Exchange Commission rules applicable to registered holding company systems. This costing methodology is also consistent with the fully allocated costing principles adopted by the MPUC in Docket No. G,E999/CI-90-1008.

Company Northern States Power Company

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MINNESOTA DEPARTMENT OF COMMERCE

Administrative Services Agreement between Northern States Power Company and other Xcel Energy Inc. Utility Operating Company Subsidiaries Reporting Requirements Stipulated in MPUC Docket No. E-002/AI-01-493

A list and the past history of all current contracts or agreements between the utility and the affiliate, the consideration received by the affiliate for such contracts or agreements, and a summary of the relevant costs records related to these ongoing transactions.
Page E-13-1 shows the additional agreements under which Xcel Energy and NSPW currently provide services (see footnote 2). The gas SCADA and gas dispatch cost sharing agreement was approved in MPUC Docket No. G002/AI-94-831. The "Restated Agreement to Coordinate Planning and Operations and Interchange Power and Energy" between the Company and NSPW was accepted for filing in FERC Docket No. ER15-1575-000 effective January 1, 2015, restating the similar 1984 "Interchange Agreement", and allocates electric production and transmission costs for the integrated electric system. Both agreements existed prior to the formation Xcel Energy Inc. and were assigned to the Company as part of the August 2000 merger transactions.

The amount of compensation and, if applicable, a brief description of the cost allocation methodology or market information used to determine cost or price.
The price or cost of the goods or services was based on the actual cost to the operating utility company providing the goods or services.

If the service or good acquired from an affiliate is competitively available, an explanation must be included stating whether competitive bidding was used, and if it was used, a copy of the proposal or a summary must be included. If it is not competitively bid, an explanation must be included stating why bidding was not used.
For 2015, the goods and services provided were billed at cost to the operating utility company affiliate and were provided on a limited "as available" basis. For this reason, there were no situations were competitive bidding was warranted.

If the arrangement is in writing, a copy of that document must be attached.
Other than the Agreement, there were no arrangements made in writing for 2015.

Company Northern States Power Company

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XCEL ENERGY COMPLIANCE REPORTING RELATED TO DOCKET NO. G,E-999/CI-90-1008

Introduction

Pursuant to the Commission's order setting filing requirements, Northern States Power Company d/b/a Xcel Energy ("Xcel Energy") responded to the Commission's ordering paragraph (3) in Docket No. G, E-999/CI-90-1008, the investigation into the competitive impact of appliance sales and service practices of Minnesota gas and electric utilities:

> "Within 60 days of the date of this order, each utility party to this proceeding shall submit a filing explaining: 1) whether its method of allocation is a fully allocated costing approach; 2) whether it complies with the recommended cost allocation principles; and 3) if it does not comply with the recommended cost allocation principles, whether its methods would accomplish similar results."

Xcel Energy had multiple non-regulated services and subsidiaries. We follow the same cost allocation process for both of these types of activities. The cost allocation approach is a fully allocated costing method as approved by the Commission in our electric and gas rate cases (E002/GR-92-1185 and G002/GR-92-1186).

The Commission's stated hierarchical cost allocation principles are:

1. Tariffed rate shall be used to value tariffed services provided to the non-regulated activity.

2. Costs shall be directly assigned to either regulated or non-regulated activities whenever possible.

3. Costs that cannot be directly assigned are common costs, which shall be grouped into homogeneous cost categories Each cost category shall be allocated based on direct analysis of the origin of the costs whenever possible. If direct analysis is not possible, common costs shall be allocated based upon an indirect cost-causative linkage to another cost category or group of cost categories for which direct assignment or allocation is available.

4. Whenever neither direct nor indirect measures of cost causation can be found, the cost category shall be allocated based upon a general allocator computed by using the ratio of all expenses directly assigned or attributed to regulated and non-regulated activities.

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Xcel Energy follows this basic approach. Our process accomplishes the proper separation of costs between Xcel Energy's regulated utility business and non-regulated operations. Each activity that can be considered outside of Xcel Energy's core electric and gas business is reviewed for regulated/non-regulated treatment. If the activity is identified as non-regulated operations, the non-regulated cost allocation process is followed.

There are limited situations where an activity that would be in the public interest and could not be pursued if a fully allocated costing approach was followed. In such circumstances, Xcel Energy has filed and will continue to file any deviation from a fully allocated costing process on a project-specific basis. Any existing exceptions have been filed and approved by the Commission.

Xcel Energy Non-regulated Cost Allocation Process

Xcel Energy's approach includes the following steps of analysis: business profiles, direct charging, cost causation allocation, corporate residual allocation, overhead allocations, and the working capital fee.

Business Profile

The allocation process begins by reviewing for each non-regulated business the services they anticipate Xcel Energy's utility business will be providing.

Direct Charges (Addresses Principle #2)

Budgeted cross charges between Xcel Energy service providers and non-regulated businesses are reviewed with the business. Any process, project or service performed for the direct benefit of a non-regulated business is directly charged to the business. The business area providing service to the non-regulated business communicates the anticipated level of service and what the cost will be for the upcoming year.

Company: Northern States Power Company

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Actual charges for labor are assigned to the non-regulated business by either setting up a fixed labor distribution or though exception time reporting. The non-labor charges are directly charged. This process enables charging for all service that is provided; including what may not have been anticipated at budget time.

Cost Causation Allocations (Addresses Principle #2)
If no direct charge has been established for a service expected it be provided, a cost causation allocation is developed. Direct charging is preferred, however, if a service is expected to be provided and was not budgeted as a direct charge, an estimate of the cost of the service is made and allocated to the non-regulated business. An example of this would be, when a service is being provided, but it is at such a minimal level that it would be very difficult or cost prohibitive to charge on a direct basis.

Overhead Costs (Addresses Principle #3)
The overhead allocation factor captures indirect costs associated with providing services to others. Xcel Energy currently uses separate rates for labor and non-labor costs. The labor overhead rate was developed based on employee related expenses (such as employee programs, employee relations, training, employment, compensation and benefits program development costs, diversity, safety), office equipment needs, and supervision of the service provider. The non-labor overhead rate is developed based on procurement and material-related costs. The overhead factor is applied to all direct charges.

Corporate Residual Allocation
For non-regulated services wholly contained within the NSP Minnesota, a portion of NSP Minnesota's corporation costs are assigned based on the relative size of the non-regulated business.

Working Capital Fee (Addresses Principle #3)
The fee is based on the current Prime Rate and is reviewed and updated quarterly. This fee is to compensate the regulated business for the cost of working capital used by the non-regulated businesses.

Summary
Xcel Energy's process has been reviewed in a number of dockets including our most recent general rate cases and complies with the common objective stated in the instant docket.

Company: Northern States Power Company

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MINNESOTA DEPARTMENT OF COMMERCE

Xcel Energy Services Cost Allocations
Summary of Review and Monitoring of Indirect Cost Allocations

As a condition of approval of the Service Agreement, between Xcel Energy Services, Inc. ("XLS" or "Service Company") and Northern States Power Company d/b/a Xcel Energy, MPUC Docket No. G,E002/AI-00-1251, Xcel Energy agreed to provide, with our Minnesota jurisdictional annual report, a summary of the review and monitoring done to ensure appropriate allocation of service company costs. In addition, the report was required to identify any changes in cost allocators or changes to companies that are allocated such costs. On August 1, 2000, XLS began operating as the Service Company of Xcel Energy Inc. The indirect cost allocators implemented at that time were those approved by the MPUC in the above docket.

Changes to Indirect Cost Allocators - Methods
The indirect cost allocation methods approved in the MPUC Docket No. E,G002/AI-14-0234 were used in the 2015 costs allocations included in this filing.

Changes to Indirect Cost Allocators – Companies Added/Deleted
For the year ended December 31, 2015, some minor changes were made in the Xcel Energy Inc. affiliate companies included in the XLS indirect cost allocators. A summary of these changes is included on 13-10 through 13-15 of this report.

Changes to Indirect Cost Allocators – Updated Base Data
For the year ended December 31, 2015, no updates were made to the base data used to develop the indirect cost allocators.

Summary of Review and Monitoring of Indirect Cost Allocators
For the year ended December 31, 2015, monthly detailed statements were sent to the affiliate company financial organizations These statements included all billings (both direct billings and indirect cost allocations) to them from XLS for their review and approval. In addition, detailed statements were also provided to the service function service providers for their review. As a result, both service receivers (affiliate companies) and service providers (service functions) initiated discussions with XLS which, in some cases, resulted in adjustments to billings and changes in indirect cost allocators. The changes included on 13-10 through 13-15 of this report is a log of the changes that were made to the indirect cost allocators as a result of this process.

Company Northern States Power Company

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Minnesota Department of Commerce

XLS JDE Indirect Allocations
Log of Additions/Deletions/Changes

Description	JDE Subledger	Status	Effective Jan-15	Effective Apr-15
Executive - Corp Governance	110			Updated Statistics
Executive (exclusive)	111	**Inactive 8-04**		Inactive
Board of Directors - Corp Gov	114			Updated Statistics
Shareholder - Corp Gov	115			Updated Statistics
Investor Relations - Corp Gov	116			Updated Statistics
Acctg, Reporting, & Taxes	120			Updated Statistics
Acctg. & Reporting - Corp Gov	121			Updated Statistics
Taxes - Corp Gov	122	**Inactive 4-14**		Inactive
Accounting - Op Co's	123			Updated Statistics
Accting PSCo & SPS	124			Updated Statistics
Accounting NSPM & NSPW	125			Updated Statistics
Acctg NSPM & NSPW Electric	126			Updated Statistics
Accounting OPCos Elec	127			Updated Statistics
Prop Trad NSPM, PSCo &SPS	128		Updated Statistics	Updated Statistics
Gen Prop Tradg OPCos	129		Updated Statistics	Updated Statistics
Audit Services	130			Updated Statistics
Audit Services - Corp Gov	131			Updated Statistics
AUDIT Serv OPCos	132			Updated Statistics
AUDIT OPCos Electric	133			Updated Statistics
AUDIT OPCos Gas	134			Updated Statistics
CA ACCTG	135			Updated Statistics
Finance & Treasury	140			Updated Statistics
Finance & Treasury - Corp Gov	141			Updated Statistics
Risk Management	142			Updated Statistics
Risk Management - Corp Gov	143			Updated Statistics
Prop Tradg FERC 557	144		Updated Statistics	Updated Statistics
Prop Gen Tradg FERC 557	145		Updated Statistics	Updated Statistics
Risk OPCos	146			Updated Statistics
Captive Insurance	147			Updated Statistics
Corporate Strategy & Bus Dev	160	**Inactive 4-14**		Inactive
Corporate Strategy & Bus Dev - Corp Gov	161			Updated Statistics
CORP STRAT OPCo	162			Updated Statistics

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XLS JDE Indirect Allocations
Log of Additions/Deletions/Changes (Cont'd)

Description	JDE Subledger	Status	Effective Jan-15	Effective Apr-15
Legal OPCo Elec	163			Updated Statistics
Legal OPCo Gas	164			Updated Statistics
Legal	170			Updated Statistics
Legal - Corp Governance	171			Updated Statistics
LEGAL NSPM & NSPW	172			Updated Statistics
LEGAL NSPM & NSPW Electric	173			Updated Statistics
LEGAL OPCos	174			Updated Statistics
Communications - Corp Gov	180			Updated Statistics
Employee Communications	181			Updated Statistics
Xcel Foundation	182			Updated Statistics
Employee Communications - exclusive	183	**Inactive 4-07**		
Branding	184			Updated Statistics
Customer Safety Advertising/Information Costs	185			Updated Statistics
HR Corp Governance	189			Updated Statistics
HR (Diversity/Safety/Emp Relations)	190			Updated Statistics
HR - Energy Supply	191	**Inactive 4-13**		
HR - Energy Delivery	192	**Inactive 4-13**		
HR - Retail	193	**Inactive 4-13**		
Payroll - South	194	**Inactive 8-04**		
Payroll - North	195	**Inactive 8-04**		
HR - Energy Markets	196	**Inactive 1-14**		
HR - Op Co's	197			Updated Statistics
Payroll	198			Updated Statistics
HR - Recruitment	199			Updated Statistics
Facilities	200	**Inactive 5-11**		
Facilities - Admin	201	**Inactive 5-11**		
Supply Chain Special Programs	220	**Inactive 1-08**		
HR - Benefits	240	**Inactive 8-04**		
Customer Service (inclusive)	400	**Inactive 12-04**		
Customer Service - South	401	**Inactive 12-04**		
Customer Service - North	402	**Inactive 12-04**		
Customer Service IT - FERC 903	403			Updated Statistics

Company Northern States Power Company

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XLS JDE Indirect Allocations
Log of Additions/Deletions/Changes (Cont'd)

Description	JDE Subledger	Status	Effective Jan-15	Effective Apr-15
Customer Service IT FERC 903 - South	404			Updated Statistics
Customer Service IT FERC 903 - North	405			Updated Statistics
Energy Deliv Fin Svcs (inclusive)	406	**Inactive 12-04**		
Federal Lobbying	409			Updated Statistics
Governmental Affairs	410			Updated Statistics
Marketing & Sales (use 412)	411	**Inactive 1-08**		
Marketing & Sales	412			Updated Statistics
Payment and Reporting	413			Updated Statistics
ES A&G FERC 921	414			Updated Statistics
Energy Markets - Fuel	415			Updated Statistics
Supply Chain	416			Updated Statistics
Rates & Regulation	417			Updated Statistics
Rates Electric	418			Updated Statistics
Rates & Regulation - all	418	**Inactive 5-05**		
Customer Service - 903	419	**Inactive 10-08**		
Customer Service - South - 903	420	**Inactive 10-08**		
Customer Service - North - 903	421	**Inactive 4-08**		
C&FO Constr, Oper & Maint	423			Updated Statistics
Receipts Processing	428	**Inactive 1-08**		
Energy Markets - Regulated Trading	429			Updated Statistics
Energy Supply Asset Management	430			Updated Statistics
Energy Markets - Business Services	431			Updated Statistics
C&FO Financial Services	432	**Inactive 1-10**		
Enterprises Financial Services	433	**Inactive 12-04**		
Shared Services Financial Services	434	**Inactive 2-10**		
Customer Care 903	435			Updated Statistics
Customer Care 902	436			Updated Statistics
Customer Care 901	437			Updated Statistics
Customer Care South 903	438			Updated Statistics
Customer Care North 903	439			Updated Statistics
Utilities Group A&G FERC 921	440			Updated Statistics
Distribution Electric FERC 580	441			Updated Statistics

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XLS JDE Indirect Allocations
Log of Additions/Deletions/Changes (Cont'd)

Description	JDE Subledger	Status	Effective Jan-15	Effective Apr-15
Transmission Electric FERC 560	442			Updated Statistics
Distribution Gas FERC 870 (E&S)	443			Updated Statistics
Transmission Gas FERC 850	444			Updated Statistics
Distribution Gas FERC 880 (Misc)	445			Updated Statistics
CC Low Income Assistance 908	446			Updated Statistics
Customer Billing FERC 903	447			Updated Statistics
Transm Elec 560 PSCo & SPS	448	**Inactive 4-14**		Inactive
Transm Elec 560 NSPM & NSPW	449			Updated Statistics
Transm Elec FERC 566	450	**Inactive 4-14**		Inactive
Transm Elec FERC 561.5	451			Updated Statistics
Transm Elec FERC 561.2	452	**Inactive 4-14**		Inactive
Distribution Elec FERC 586	453			Updated Statistics
Distribution Gas FERC 878	454			Updated Statistics
ES Misc Power Expense Op Co's	455			Updated Statistics
ES Misc Power Expense North	456			Updated Statistics
ES Misc Power Expense South	457			Updated Statistics
ES Operations Management OPCo's	458			Updated Statistics
ES Operations Management North	459			Updated Statistics
ES Operations Management South	460			Updated Statistics
ES Engineering & Construction OPCo's	461			Updated Statistics
ES Engineering & Construction North	462			Updated Statistics
ES Engineering & Construction South	463			Updated Statistics
ES Environmental Policy & Services OPCo's	464			Updated Statistics
ES Environmental Policy & Services North	465			Updated Statistics
ES Environmental Policy & Services South	466			Updated Statistics
Transm Elec FERC 561.5 North	467	**Inactive 4-14**		Inactive
Transm Elec FERC 566	468			Updated Statistics
Elec Dist FERC 588	469			Updated Statistics
Gas Dist FERC 813	470			Updated Statistics
Elec Dist FERC 588 North	471			Updated Statistics
Elec Dist FERC 588 South	472			Updated Statistics
Gas Dist FERC 813 North	473			Updated Statistics
Gas Dist/Elec Dist/Gas Trans Finance FERC 588, 880, 859	474			Updated Statistics

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MINNESOTA DEPARTMENT OF COMMERCE

XLS JDE Indirect Allocations
Log of Additions/Deletions/Changes (Cont'd)

Description	JDE Subledger	Status	Effective Jan-15	Effective Apr-15
Non-labor alloc. following labor	910	**Inactive 1-10**		
Labor allocator	920	**Inactive 3-07**		
Business Systems	500			
CIS (Customer Information System) (use 503)	501	**Inactive 4-07**		
CSS (use 503)	502	**Inactive 4-07**		
CRS (Customer Resource System)	503			Updated Statistics
Maximo	504			Updated Statistics
JDE (J.D. Edwards)	505			Updated Statistics
GIS (Geographic Information System) Distribution	506			Updated Statistics
OMS (Outage Management System)	507			Updated Statistics
e-Business	508			Updated Statistics
Passport - all modules	509			Updated Statistics
Passport - Accounts Payable	510			Updated Statistics
Passport - Inventory	511	**Inactive 3-11**		
Passport - Work Management	512			Updated Statistics
Passport - Purchasing	513			Updated Statistics
Misc. Applications	514			Updated Statistics
PeopleSoft	515			Updated Statistics
PowerPlant	516			Updated Statistics
GMS (Gas Management System)	517			Updated Statistics
MDMS (Monitoring Devise Management System)	518			Updated Statistics
CL/QM (Call Logging and Quality Management)	519			Updated Statistics
IVR (Interactive Voice Response)	520			Updated Statistics
Time/PTRS	521			Updated Statistics
ERS (Electric Reliability System)	522	**Inactive 1-12**		
Network	523			Updated Statistics
DSS Support	524			Updated Statistics
Utility Innovations	525			Updated Statistics
EMS-Transmission (Energy Mgmt System-SCADA)	526			Updated Statistics
EMS-Distribution (Energy Mgmt System-SCADA)	527			Updated Statistics
EMS-Shared (Energy Mgmt System-SCADA)	528			Updated Statistics
Mercury Interactive	529			Updated Statistics
DAMS (Delivery Asset Management System)	530	**Inactive 3-11**		
Gas SCADA	531			Updated Statistics
Utility Innovations - Advertising	532	**Inactive 1-12**		
CBS/ALS/CFM	533			Updated Statistics
CES	534			Updated Statistics
Altra Power (ACES)	535			Updated Statistics

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XLS JDE Indirect Allocations
Log of Additions/Deletions/Changes (Cont'd)

Description	JDE Subledger	Status	Effective Jan-15	Effective Apr-15
Design Tool	536			Updated Statistics
Eclipse	537			Updated Statistics
Electronic Deal Ticketing	538	**Inactive 3-11**		
Flipper	539			Updated Statistics
Meter Reading Acquisition System (MRAS)	540			Updated Statistics
Panorama	541	**Inactive 3-11**		
PCI	542			Updated Statistics
Transmission Accounting and Billing System(TABS)	543	**Inactive 3-11**		
EAI/ESB (Enterprise Application Integration/Enterprise Service Bus)	544			Updated Statistics
CBS Municipal Billing System	545	**Inactive 3-11**		
CFO Systems	549			Updated Statistics
HR Systems	550			Updated Statistics
Corporate Systems	551			Updated Statistics
Security Systems	552			Updated Statistics
Energy Supply Systems	553			Updated Statistics
Business Objects	554			Updated Statistics
Revenue Reporting System (RRS)	555			Updated Statistics
FARRMS REC	556	**Inactive 3-11**		
Mobile Computing	559			Updated Statistics
GIS (Geographic Information System) Transmission	560	**Inactive 1-12**		
Enterprise Continuity	561			Updated Statistics
Mainframe Charges From IBM	562			Updated Statistics
SAP General Ledger	563			

Reviews (Non IT)	**Jan-15**	**Apr-15**
Input/update data in Matrix	Carrie Authier	Carrie Authier
Verified Matrix links to allocations sheets	Jim Foland	Andy Sawyer
Reviewed input for keying errors	Jim Foland	Andy Sawyer
Serivce Company Acctg verified and approved input data for reasonableness	Olga Odell	Andy Sawyer/Adam Dietenberger
Reviewed report (R55VNUA)- verified all total 100%	Carrie Authier	Andy Sawyer
These reviews should be done and signed off on after every update to the allocations.		

Reviews (IT)	**Jan-15**	**Apr-15**
Input/update data in Matrix	Carrie Authier	Carrie Authier
Verified Matrix links to allocations sheets	Jim Foland	Andy Sawyer
Reviewed input for keying errors	Jim Foland	Andy Sawyer
Serivce Company Acctg verified and approved input data for reasonableness	Olga Odell	Andy Sawyer/Adam Dietenberger
Reviewed report (R55VNUA)- verified all total 100%	Carrie Authier	Andy Sawyer
These reviews should be done and signed off on after every update to the allocations.		

Company Northern States Power Company

(Minnesota Gas Jurisdiction)
For Calendar Year 2015

MINNESOTA DEPARTMENT OF COMMERCE

GAS PLANT IN SERVICE

In addition to Account 101, Gas Plant in Service (Classified), this schedule includes Account 102, Gas Plant Purchased or Sold, Account 103, Experimental Gas Plant Unclassified and Account 106, Completed Construction Not Classified-Gas.)

1 Report the original cost of gas plant in service according to the accounts prescribed on the following page.

2 Corrections of additions, and retirements for the current or the preceding year should be included in column (b) or (c) as appropriate, not in column (d).

3 Credit adjustments to plant accounts should be enclosed in parentheses to indicate the negative effect of such amounts.

4 Reclassification or transfers within utility plant accounts should be shown in column (e). Include also in column (e) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, Gas Plant Purchased or Sold. In showing the clearance of Account 102, include in column (d) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (e) only the offset to the debits or credits distributed in column (e) to primary account classifications.

5 Show accounts 307-318 if jurisdictional amounts are other than zero.

NOTE

Completed Construction Not Classified, Account 106, shall be classified in this schedule into prescribed accounts on an estimated basis if necessary, and the entries included in column (b). Also to be included in column (b) are entries for reversals of tentative distributions of the prior year reported in column (b).

Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, a tentative distribution of such retirements, on an estimated basis with appropriate contra entry to the account for accumulated depreciation provision, shall be included in column (c). Included also in column (c) reversals of tentative distributions of prior year of unclassified retirements.

Use space below for showing the account distributions of these tentative classifications in columns (b) and (c) including the reversals of the prior year tentative acct distributions of these amounts. Careful observance of the above instructions and the text of accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at the end of year.

Please efile a separate document with your report's submission called Plant in Service if this page does not work for you.

Company Northern States Power Company

(Minnesota Gas Jurisdiction)
For Calendar Year 2015

MINNESOTA DEPARTMENT OF COMMERCE

GAS PLANT IN SERVICE

Acct. No.	TITLE OF ACCOUNTS		B.O.Y. BALANCE (a)	ADDITIONS (b)	RETIREMENTS (c)	ADJUSTMENTS (d)	TRANSFERS (e)	E.O.Y. BALANCE (f)
	Intangible plant							
301	Organization							
302	Franchises and consents							
303	Misc. intangible plant*							
	Total intangible plant							
	Production Plant							
	Mfd. gas production plant:							
304	Land and land rights							
305	Structures & Improvements							
306	Boiler plant equipment							
307	Other power equipment							
308	Coke ovens							
309	Producer gas equipment							
310	Water gas generating equip.							
311	Liquefied petro. gas equip.							
312	Oil gas generating equip.							
313	Generating equip. - Other processes							
314	Coal, coke, and ash handling equip.							
315	Catalytic cracking equip.							
316	Other reforming equip.							
317	Purification equip.							
318	Residual refining equip.							
319	Gas mixing equip.							
320	Other equip.							
325-47	Natural Gas Production Plant							
	Total production plant	(1)	16,892					17,192

(Continued on next page)

State the nature of plant included in this account and if substantial in amount submit a supplementary schedule showing subaccount classification of such plant conforming to the requirements of this schedule.

(1) See Note on Page G-16A.

Company Northern States Power Company

(Minnesota Gas Jurisdiction)
For Calendar Year 2015

MINNESOTA DEPARTMENT OF COMMERCE

GAS PLANT IN SERVICE

Acct. No.	TITLE OF ACCOUNTS		B.O.Y. BALANCE (a)	ADDITIONS (b)	RETIREMENTS (c)	ADJUSTMENTS (d)	TRANSFERS (e)	E.O.Y. BALANCE (f)
	Natural Gas Storage							
350-363	Underground Storage Plant							
364	Liquefied natural Gas Plant							
	Total natural gas storage	(1)	47,252					47,228
	Transmission Plant							
365.1	Land and land rights							
365.2	Rights-of-way							
366	Structures and Improvements							
367	Mains							
368	Compressor station equip.							
369	Measuring and regulating station equip.							
370	Communication equip.							
371	Other equip.							
	Total Transmission	(1)	72,353					75,388
	Distribution Plant							
374	Land and land rights							
375	Structures & Improvements							
376	Mains							
377	Compressor station equip.							
378	Meas. & reg. sta. equip.-gen.							
379	Meas. & reg. sta. equip. + CG.							
380	Services							

(Continued on next page)

(1) See Note on Page G-16A.

Company Northern States Power Company

(Minnesota Gas Jurisdiction)
For Calendar Year 2015

Minnesota Department of Commerce

GAS PLANT IN SERVICE

Acct. No.	TITLE OF ACCOUNTS		B.O.Y. BALANCE (a)	ADDITIONS (b)	RETIREMENTS (c)	ADJUSTMENTS (d)	TRANSFERS (e)	E.O.Y. BALANCE (f)
	Distribution Plant							
381	Meters							
382	Meter installations							
383	House regulators							
384	House reg. install.							
385	Indus. meas. & reg. equip.							
386	Other prop. on cust. prem.							
387	Other equip.							
	Total distribution	(1)	852,729					912,689
	General Plant							
389	Land and land rights							
390	Structures & Improvements							
391	Office. furn. & equip.							
392	Trans. equip.							
393	Store equip.							
394	Tools, shop., & gar. equip.							
395	Laboratory equip.							
396	Power operated equip.							
397	Communications equip.							
398	Miscellaneous equip.							
399	Other tangible property*							
	Total general plant	(1)	45,516					47,454
	Total gas plant in service	(2)	1,034,742					1,099,951

* State the nature and use of plant included in this account and if substantial in amount submit a supplementary schedule showing subaccount classification of such plant conforming to the requirements of this schedule.

(1) See Note on Page G-16A.
(2) Total Gas Plant in Service does not include Common Utility Plant. See note on Page G-16A.

Company Northern States Power Company
For Year Ended December 31, 2015
Dollars in Thousands

MINNESOTA DEPARTMENT OF COMMERCE

(Minnesota Gas Jurisdiction)
For Calendar Year 2015

(1) The Gas Plant in Service total does not include Common Utility Plant allocated to gas in the amount of:

Beginning of Year	$58,283
End of Year	$64,266

NOTE

Gas Plant in Service

Detail is available on a total Company basis only. Because Xcel Energy is a multi-utility, multi-jurisdiction Company, beginning of year (BOY) and end of year (EOY) balances are the result of allocations and direct assignments to the Minnesota jurisdiction through the cost of service study (COSS). The COSS does not have the capability to develop the Minnesota jurisdiction detail requested. Detail provided in this section and throughout the report is comparable to that which would be submitted for support during a rate case.

Company Northern States Power Company

(Minnesota Gas Jurisdiction)
For Calendar Year 2015

MINNESOTA DEPARTMENT OF COMMERCE

ANALYSIS OF RESERVES

Acct. No.	TITLE OF ACCOUNTS		B.O.Y. BALANCE (a)	Credits ACCRUALS (b)	Credits GR. SALV. (c)	debits RETIREMENT (d)	debits REMOVAL (e)	TRANSFERS & ADJUSTMENTS (f)	E.O.Y. BALANCE (g)
	Intangible Plant								
301	Organization								
302	Franchises and consents								
303	Misc. intangible plant								
	Total intangible plant								
	Production Plant								
	Mfd. gas production plant:								
305	Structures & Improvements								
306	Boiler plant equipment								
307	Other power equipment								
308	Coke ovens								
309	Producer gas equipment								
310	Water gas generating equip.								
311	Liquefied petro. gas equip.								
312	Oil gas generating equip.								
313	Generating equip. - Other processes								
314	Coal, coke, and ash handling equip.								
315	Catalytic cracking equip.								
316	Other reforming equip.								
317	Purification equip.								
318	Residual refining equip.								
319	Gas mixing equip.								
320	Other equip.								
325-47	Natural Gas Production Plant								
	Total production plant	(1)	13,117						13,735

(Continued on next page)

(1) See Note on Page G-19A.

Company Northern States Power Company

(Minnesota Gas Jurisdiction)
For Calendar Year 2015

MINNESOTA DEPARTMENT OF COMMERCE

ANALYSIS OF RESERVES

Acct. No.	TITLE OF ACCOUNTS		B.O.Y. BALANCE (a)	Credits ACCRUALS (b)	Credits GR. SALV. (c)	debits RETIREMENT (d)	debits REMOVAL (e)	TRANSFERS & ADJUSTMENTS (f)	E.O.Y. BALANCE (g)
	Natural Gas Storage								
350-363	Underground Storage Plant								
364	Liquefied Natural Gas Plant								
	Total natural gas storage	(1)	26,363						28,159
	Transmission Plant								
365.1	Land and land rights								
365.2	Rights-of-way								
366	Structures and Improvements								
367	Mains								
368	Compressor station equip.								
369	Measuring and regulating station equip.								
370	Communication equip.								
371	Other equip.								
	Total Transmission	(1)	27,460						25,996
	Distribution Plant								
374	Land and land rights								
375	Structures & Improvements								
376	Mains								
377	Compressor station equip.								
378	Meas. & reg. sta. equip. -gen.								
379	Meas. & reg. sta. equip. +CG.								
380	Services								

(Continued on next page)

(1) See Note on Page G-19A.

Company Northern States Power Company

(Minnesota Gas Jurisdiction)
For Calendar Year 2015

MINNESOTA DEPARTMENT OF COMMERCE

ANALYSIS OF RESERVES

Acct. No.	TITLE OF ACCOUNTS		Credits B.O.Y. BALANCE (a)	Credits ACCRUALS (b)	Credits GR. SALV. (c)	debits RETIREMENT (d)	debits REMOVAL (e)	TRANSFERS & ADJUSTMENTS (f)	E.O.Y. BALANCE (g)
	Distribution Plant								
381	Meters								
382	Meter installations								
383	House regulators								
384	House reg. install.								
385	Indus. meas. & reg. equip.								
386	Other prop. on cust. prem.								
387	Other equip.								
	Total distribution	(1)	399,801						417,139
	General Plant								
389	Land and land rights								
390	Structures & Improvements								
391	Office. furn. & equip.								
392	Trans. equip.								
393	Store equip.								
394	Tools, shop., & gar. equip.								
395	Laboratory equip.								
396	Power operated equip.								
397	Communications equip.								
398	Miscellaneous equip.								
399	Other tangible property								
	Total general plant	(1)	23,406						25,241
	Total gas plant in service (2)	(1)	490,147						510,270

(1) See Note on Page G-19A.
(2) Total Reserve excludes Common Utility Reserves. See Note on Page G-19A.

Company Northern States Power Company
For Year Ended December 31, 2015
Dollars in Thousands

(Minnesota Gas Jurisdiction)
For Calendar Year 2015

(1) The Depreciation Reserve total does not include Common Utility allocated to gas in the amount of:

Beginning of Year	$33,313
End of Year	$36,870

NOTE

Analysis of Depreciation Reserve

Detail is available on a total Company basis only. Because Xcel Energy is a multi-utility, multi-jurisdiction Company, beginning of year (BOY) and end of year (EOY) balances are the result of allocations and direct assignments to the Minnesota jurisdiction through the cost of service study (COSS). The COSS does not have the capability to develop the Minnesota jurisdiction detail requested. Detail provided in this section and throughout the report is comparable to that which would be submitted for support during a rate case.

Company Northern States Power Company

(Minnesota Gas Jurisdiction)
For Calendar Year 2015

MINNESOTA DEPARTMENT OF COMMERCE

SUMMARY OF ACCRUALS

		S/L STRAIGHT LINE METHOD							
Acct. No.	TITLE OF ACCOUNTS	ESTIMATED NET SALVAGE GROSS PLANT (a)	ESTIMATED NET SALVAGE % (b)	AMOUNT (c)	DEPRECIATION RESERVE (d)	NET BALANCE (e)	SERVICE & LIFE (f)	ANNUAL ACCRUAL (g)	S/L % (h)
	Intangible Plant								
301	Organization								
302	Franchises and consents								
	Intangible Plant								
303	Misc. intangible plant								
	Total intangible plant								
	Production Plant								
	Mfd. gas production plant:								
304	Land and land rights								
305	Structures and Improvements								
306	Boiler plant equipment								
307	Other power equipment								
308	Coke ovens								
309	Producer gas equip.								
310	Water gas generating equip.								
311	Liquefied petro. gas equip.								
312	Oil gas generating equip.								
313	Generating equip. -								
	Other processes								
314	Coal, coke, and ash handling equip.								
315	Catalytic cracking equip.								
316	Other reforming equip.								
317	Purification equip.								
318	Residual refining equip.								
319	Gas mixing equip.								
320	Other equip.								
325-47	Natural Gas Production Plant								
	Total production plant (1)	16,504			13,735	2,769		650	

Continued on next page

(1) EOY Gross Plant excludes Land

Company Northern States Power Company

(Minnesota Gas Jurisdiction)
For Calendar Year 2015

SUMMARY OF ACCRUALS

			S/L STRAIGHT LINE METHOD							
Acct. No.	TITLE OF ACCOUNTS		ESTIMATED NET SALVAGE GROSS PLANT (a)	ESTIMATED NET SALVAGE % (b)	AMOUNT (c)	DEPRECIATION RESERVE (d)	NET BALANCE (e)	SERVICE & LIFE (f)	ANNUAL ACCRUAL (g)	S/L % (h)
	Natural Gas Storage									
350-363	Underground Storage Plant									
364	Liquefied Natural Gas Plant									
	Total natural gas storage	(1)	47,228			28,159	19,069		1,850	
	Transmission Plant									
365.1	Land and land rights									
365.2	Rights-of-way									
366	Structures & Improvements									
367	Mains									
368	Compressor station equip.									
369	Measuring and regulating Station Equip.									
370	Communication equip.									
371	Other equip.									
	Total Transmission	(1)	74,764			25,996	48,768		1,393	
	Distribution Plant									
374	Land and land rights									
375	Structures & Improvements									
376	Mains									
377	Compressor station equip.									
378	Meas. & reg. sta. equip.-gen.									
379	Meas. & reg. sta. equip. + CG.									
380	Services									

Continued on next page

(1) EOY Gross Plant excludes Land

Company Northern States Power Company

SUMMARY OF ACCRUALS

(Minnesota Gas Jurisdiction)
For Calendar Year 2015

MINNESOTA DEPARTMENT OF COMMERCE

Acct. No.	TITLE OF ACCOUNTS		S/L STRAIGHT LINE METHOD ESTIMATED NET SALVAGE GROSS PLANT (a)	ESTIMATED NET SALVAGE % (b)	AMOUNT (c)	DEPRECIATION RESERVE (d)	NET BALANCE (e)	SERVICE & LIFE (f)	ANNUAL ACCRUAL (g)	S/L % (h)
	Distribution Plant									
381	Meters									
382	Meter installations									
383	House regulators									
384	House reg. install.									
385	Indus. meas. & reg. equip.									
386	Other prop. on cust. prem.									
387	Other equip.									
	Total distribution	(1)	912,320			417,139	495,181		27,105	
	General Plant									
389	Land and land rights									
390	Structures & Improvements									
391	Office. furn. & equip.									
392	Trans. equip.									
393	Store equip.									
394	Tools, shop., & gar. equip.									
395	Laboratory equip.									
396	Power operated equip.									
397	Communications equip.									
398	Miscellaneous equip.									
399	Other tangible property									
	Total general plant	(1)	47,311			25,241	22,070		2,453	
	Total gas plant in service	(1)	1,098,127			510,270	587,857		33,451	

(1) EOY Gross Plant excludes Land

(2) Common Utility Plant allocated to the Gas Utility is excluded in the amount of EOY Gross Plant 63,836, Depr Reserve 36,870, Net Balance 26,966 and Annual Accrual 5,148.

Company Northern States Power Company

(Minnesota Gas Jurisdiction)
For Calendar Year 2015

MINNESOTA DEPARTMENT OF COMMERCE

ANALYSIS OF SELECTED UTILITY PLANT ACCOUNTS

Acct. No.	TITLE OF ACCOUNTS	B.O.Y. BALANCE (a)	DEBITS (b)	CREDITS (c)	E.O.Y. BALANCE (d)
101.1	Property under capital leases				
102	Gas plant purchased*				
102.1	Gas plant sold*				
103	Exper. gas plant. unclassif.				
104	Gas Plant Leased to Others				
105	Gas Plant Held for Future Use				
105.1	Prod. properties held for future use (Major only)				
106	Completed constr. not classif.- Gas (Major only)				
107	Constr. work in progress - Gas				
114	Gas plant acquisition adj.				
116	Other gas plant adjustments				
117	Gas stored underground -Noncurrent (Major only)				
118	Other utility plant				
	Total utility plant				
	DEFERRED DEBITS (2)				
	Unamortized debt expense (1) 131 Cash and 135 Working Funds				19
181	(1) 143 Other Accounts Receivables				393
182.1	Extraordinary property losses				
182.2	Unrecovered plant and regulatory study costs				
183.1	Preliminary natural gas survey and investigation charges				

* For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchaser, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date of such filing.

(1) Data reflects Jurisdictional Determinations based on analysis of the 2015 Misc Debits and Credits.

(2) Deferred Debits do not include the Gas Utility Infrastructure Cost Rider (Docket G002/M-14-336) of $16,909,615 at December 31, 2015 recorded in FERC Account 182.3.

Continued on next page

Company Northern States Power Company

(Minnesota Gas Jurisdiction)
For Calendar Year 2015

MINNESOTA DEPARTMENT OF COMMERCE

ANALYSIS OF SELECTED UTILITY PLANT ACCOUNTS

Acct. No.	TITLE OF ACCOUNTS	B.O.Y. BALANCE (a)	DEBITS (b)	CREDITS (c)	E.O.Y. BALANCE (d)
183.2	Other preliminary survey and investigation charges				
184	Clearing accounts (Major only)				
185	Temporary facilities (Major only)				
186	Misc. deferred debits*				
187	Deferred losses from disposition of utility plant				
188	Research, devel. and demonst. expend. (Major only)				
189	Unamort. loss on reacq. debt.				
191	Unrecovered purchased gas costs				
	deferred credits				
232/235	Accounts Payable/Customer Deposits (1)				-1,060
252	Customer Advances for Construction				-389
253	Other Deferred Credits*				
256	Deferred Gains from Disposition of Utility Plant				
257	Unamortized Gain on Debt.				

* If substantial in amount, Please efile a separate document with this report for additional information, showing subaccount classification of such deferred debits and/or credits and the balances for each contained in columns (a) through (d).

(1) Data reflects Jurisdictional Determinations based on analysis of the 2015 Misc Debits and Credits.

Company Northern States Power Company

Page G-24A

For Year Ended 12/31/15

(Minnesota Gas Jurisdiction)
For Calendar Year 2015

Minnesota Department of Commerce

Other Components of Net Investment Rate Base

The company does not maintain separate accounts by jurisdiction for other components of the investment rate base. Many accounts are common in nature between the electric and gas utility. Others pertain only to the gas utility. Allocated jurisdictional balances are shown for selective accounts which would likely comprise components of rate base for a general rate increase application.

Company Northern States Power Company

(Minnesota Gas Jurisdiction)
For Calendar Year 2015

MINNESOTA DEPARTMENT OF COMMERCE

MATERIALS AND SUPPLIES (Minnesota Jurisdiction)

1. For Account 154, report the amount of plant materials and operating supplies at end of year under titles which are indicative of the character of the material included.
2. Give an explanation of important inventory adjustments during year (on page 25 extra) showing general classes of material and supplies and the various accounts (operating expense, clearing accounts, plant, etc.) affected - debited or credited. Debits of credits to stores expense-clearing shall be shown separately, if applicable.
3. Give a concise explanation of the inventory cost method currently being used for each account reported below:
Please efile a separate document with this report for additional information.

ACCOUNT	BALANCE	B.O.Y. BALANCE (a)	E.O.Y. (b)
151	FUEL STOCK	3,259	2,790
152	FUEL STOCK EXP. UNDIST.		
153	RESIDUAL & EXTRACTED PROD		
155	MERCHANDISE		
156	OTHER MATERIALS & SUPP		
163	STORES EXPENSE UNDIST.		
164.1	GAS STORED UNDERGROUND	41,048	25,727
164.2	LIQUID NATURAL GAS STORED	5,232	5,692
154	PLANT MATLS. OPER. SUPPL.	1,115	67
	(list details)		
154	TOTAL		
	TOTAL MATLS. & SUPPLIES	50,655	34,276

Company Northern States Power Company

(Minnesota Gas Jurisdiction)
For Calendar Year 2015

MINNESOTA DEPARTMENT OF COMMERCE

ACCUMULATED DEFERRED INCOME TAXES - ACCOUNT 281,282,283

	CHANGES DURING YEAR					ADJUSTMENTS DURING YEAR				
ACCOUNT SUBDIVISIONS	B.O.Y BALANCE (a)	AMT. DR ACCT. 410.1 (b)	AMT. CR. ACCT. 411.1 (c)	AMT. DR ACCT 410.2 (d)	AMT. CR. ACCT. 411.2 (e)	DEBITS-DR ACC. NO. (f)	AMOUNT (g)	CREDIT=CR ACC. NO. (h)	AMOUNT (i)	E.O.Y BALANCE (j)
ACCOUNT 281:										
Defense Facilities										
Pollution Control										
OTHER (Specify)										
Total Account 281										
CLASSIF. OF TOTAL										
Fed. Inc. Tax										
State Inc. Tax										
Local Inc. Tax										
ACCOUNT 282:										
Other (Specify)										
Total Account 282										
CLASSIF. OF TOTAL										
Fed. Inc. Tax										
State Inc. Tax										
Local Inc. Tax										
ACCOUNT 283:										
OTHER (Specify)										
Total										
OTHER (specify)										
Total Account 283										
CLASSIF. OF TOTAL										
Fed. Inc. Tax										
State Inc. Tax										
Local Inc. Tax										

* See Page G-29A for data that is available.
** See Page G-29B for data that is available.

Company Northern States Power Company

(Minnesota Gas Jurisdiction)
For Calendar Year 2015

BASIS OF CALCULATION OF ACCUMULATED DEFERRED INCOME TAXES - ACCOUNT 281

Please efile a separate document with this report for additional information.

CERTIFI-CATION NUMBER (a)	Description of PROPERTY ITEM (b)	COSTS OF PROPERTY ITEM TOTAL (c)	AMORITIZ-ABLE	START DATE OF TAX AMORTZ (e)	NORMAL DEPR RATE FOR DEFERRED TAX (f)	TAX RATES APPLIED TO ORIGINALLY DEFERRED AMOUNTS (g)	CUR. YR. TO AMORTIZE PREV. DEPN. (h)

* See Page G-29A for data that is available.
** See Page G-29B for data that is available.

Company Northern States Power Company

(Minnesota Gas Jurisdiction)
For Calendar Year 2015

Please efile a separate document with this report for additional information.

METHODS OF CALCULATING ACCUMULATED DEFERRED INCOME TAXES - ACCOUNT 282

1. Show the type of life estimate used in column (d), such as "useful life," "guideline life," "guideline class life," etc.

2. Show references where they will improve the report's clarity.

CLASSIFICATION OF PLANT (a)	LIBERALIZED DEPRECIATION METHOD (b)	DATE METHOD APPLIED (c)	LIFE ESTIMATE (SEE INSTR. 1) (d)

* See Page G-29A for data that is available.
** See Page G-29B for data that is available.

Company Northern States Power Company

(Minnesota Gas Jurisdiction)
For Calendar Year 2015

ANNUAL RECAP OF ACCUMULATED REFERRED INCOME TAXES-ACCOUNT 282

1. Please efile a separate document with this report for additional information,containing explanations where necessary.
2. Show on separate lines the values for each year from Calendar year 2012 to calendar year 2015 of report.
3. Explain the basis used to defer amounts for the last year (straight line tax rate to liberalized tax rate, etc.).
4. State whether accounting for liberalized depreciation has been directed or approved by any other state or commission -- column (d).
5. Show references where they will improve the report's clarity.

YEAR	YEAR'S TAX DEFFERRAL (a)	TOTAL DR (ACCOUNT 282) CR (ACCT. 411.1) (b)	OTHER STATE APPROVALS (c)

Additional information

* See Page G-29A for data that is available.
** See Page G-29B for data that is available.

Company Northern States Power Company
For Year Ended December 31, 2015
Dollars in Thousands

MINNESOTA DEPARTMENT OF COMMERCE

(Minnesota Gas Jurisdiction)
For Calendar Year 2015

Accumulated Deferred Income Taxes Minnesota Jurisdiction	Beginning Balance	Ending Balance
Production	$353	$444
Storage	4,448	4,170
Transmission	10,145	11,193
Distribution	124,263	139,504
General	6,992	7,046
Other (Common)	4,516	5,017
Net Operating Loss (NOL) Carry Forward	(10,276)	(4) (1)
Non-Plant Related	14,103	1,986
Total	$154,544	$169,356

(1) Net Operating Loss (NOL) Carry Forward Ending Balance is ($4) for 2015 Actual.
On a weather normalized basis this amount would be ($4).

Detail is available on a total company basis only. Because Xcel Energy is a multi-utility, multi- jurisdictional company, beginning of year (BOY) and end of year (EOY) balances for accumulated deferred income taxes are the result of allocations and direct assignments to the Minnesota jurisdiction through the cost of service study (COSS). The COSS does not have the capability to develop the Minnesota jurisdiction detail requested. Detail provided in this section and throughout this report is comparable to that which is submitted for support during a rate case.

Company Northern States Power Company

(Minnesota Gas Jurisdiction)
For Calendar Year 2015

MINNESOTA DEPARTMENT OF COMMERCE

ACCUMULATED DEFERRED INCOME TAXES - ACCOUNT 281

The Company maintains its annual and accumulated deferred tax information for Defense Facilities, Pollution Control Equipment, and other 281 property at the following level of detail:

1. By type of equipment (i.e. Pollution Control, etc.)
2. By vintage of installation
3. All jurisdictions combined

An allocation process is used to develop the Minnesota Jurisdiction portion of this information for rate-making. The FERC Form 1 contains this data in a combined form for all jurisdictions.

Deferred tax additions to Account 281 are reversed using the composite book life from the appropriate property class. Additions to this deferred tax account are calculated by applying a composite state and federal tax rate to the tax deduction.

ACCUMULATED DEFERRED INCOME TAXES - ACCOUNT 282

The Company maintains its annual and accumulated deferred tax information for Account 282 at the following level of detail:

1. By tax guideline (i.e. Steam Production, Trans., Dist., etc.)
2. By vintage of installation
3. All jurisdictions combined

An allocation process is used to develop the Minnesota Jurisdiction portion of this information for rate-making. The FERC Form 1 contains this data in a combined form for all jurisdictions.

The Company over the years has made a variety of accelerated depreciation elections. Prior to 1962, facts and circumstances were used to determine the depreciation deduction using the straight-line method. In 1962, the Company elected Guideline procedures and two different accelerated methods; DCB for Transmission and Distribution property and SYD for other property under the Guideline System. The method is switched to straight-line when it is advantageous. In 1971 the Company elected to apply the accelerated depreciation procedures made available under the Asset Depreciation Range (ADR) System. For the 1971, 1976, and 1977 vintage additions, the Company elected the modified half-year provision under ADR and used the SYD method of depreciation. For the 1972, 1973, 1974, 1975, 1978, 1979, and 1980 vintage addition, the Company elected the standard half-year convention option under the ADR system and calculated depreciation using the DCB method for two years and then switching to the SYD method over the remaining life of the vintage group. In 1982, the Company elected to apply the Accelerated Cost Recovery System as provided by the Economic Tax Recovery Act of 1981. The Tax Reform Act of 1986 required a modified Accelerated Cost Recovery System Depreciation for property constructed after 1986.

Company Northern States Power Company

(Minnesota Gas Jurisdiction)
For Calendar Year 2015

Due to the variety of accelerated methods used in the past, deferred balances are not defined for each method. However, a vintage deferred record is kept for each guideline class of property and is computer based on the difference between the accelerated depreciation and straight-line book recovery without jurisdictional separation.

ACCUMULATED DEFERRED INCOME TAXES - ACCOUNT 283

The level of detail maintained for Account 283 is basically the same as that described for Account 281 and Account 282.

ACCUMULATED DEFERRED INCOME TAXES - ACCOUNT 190

The Company maintains its annual and accumulated deferred tax information for Account 190 at the following level of detail:

1. By deferred category
2. By vintage of occurrence
3. All jurisdictions combined (except decommissioning)

An allocation process is used to develop the Minnesota jurisdiction portion of this information for rate-making. The FERC Form 1 contains this data in a combined form for all jurisdictions.

Deferred tax additions to Account 190 are reversed through tax deductions. Additions to this deferred tax account are calculated by applying a composite state and federal tax rate to the book expense.

Company Northern States Power Company

(Minnesota Gas Jurisdiction)
For Calendar Year 2015

MINNESOTA DEPARTMENT OF COMMERCE

STATEMENT OF INCOME FOR THE YEAR

Acct. No.	ACCOUNT NAME	1 Current Year Normalized for Weather Where Appropriate	2 Current Year Unnormalized Data	3 Projected Year Data Normalized for Weather
	Utility Operating Income			
400	Operating Revenues (Before taxes)(Page 34)	493,142	487,955	472,782
	Operating Expenses:			
401	Operation			
402	Maintenance Expenses	378,858	378,858	356,266
403	Depreciation Expense	38,598	38,598	41,216
404-5	Amort. & Depl. of Utility Plant			
406	Amort. of Utility Plant Acq. Adj.			
407	Amort. of Commission Approved Deferrals (List Separately)			
407.1	Amort. of Property Losses Unrecovered Plant and Regulatory Study Costs	6,987	6,987	4,566
407.2	Amort. of Conversion Expenses			
408.1	Taxes Other Than Income	19,802	19,802	21,529
409.1	Income Taxes - Federal	2,553	915	7,763
409.1	- Other	792	284	2,410
410.1	Provision for Deferred Income Taxes	12,101	12,101	4,955
411.1	(Less) Provision for Deferred Income Taxes -- Cr.			
411.4	Investment Tax Credit Adj. -- Net	-279	-279	-268
411.6	(Less) Gains from Disp. of Utility Plant			
411.7	Losses from Disp. of Utility Plant			
	TOTAL Utility Operating Expenses	459,413	457,267	438,437
	Net Utility Operating Income	33,729	30,688	34,345

Provide notes to Statement of Income below.

(Continued on next page)

Company Northern States Power Company

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(Minnesota Gas Jurisdiction)
For Calendar Year 2015

STATEMENT OF INCOME FOR THE YEAR

Amort. Of Commission Approved Deferrals	1 Current Year Normalized for Weather Where Appropriate	2 Current Year Unnormalized Data	3 Projected Year Data Normalized for Weather
State Energy Policy	1,064	1,064	0
Rate Case Amortization	0	0	0
Deferred Sewer Separation / Gas Safety	5,923	5,923	4,566
TOTAL	6,987	6,987	4,566

Company Northern States Power Company

(Minnesota Gas Jurisdiction)
For Calendar Year 2015

STATEMENT OF INCOME FOR THE YEAR

Acct. No.	ACCOUNT NAME	1 Current Year Normalized for Weather Where Appropriate	2 Current Year Unnormalized Data	3 Projected Year Data Normalized for Weather
	OTHER INCOME AND DEDUCTIONS			
	Other Income			
	Nonutility Operating Income			
415	Revenues From Merchandising, Jobbing and Contract Work			
416	(Less) Costs and Exp. of Merchandising, Job. & Contract Work			
417	Revenues From Nonutility Operations			
417.1	(Less) Expenses of Nonutility Operations			
418	Nonoperating Rental Income			
418.1	Equity in Earnings of Subsidiary Companies			
419	Interest and Dividend Income			
419.1	Allowance for Other Funds Used During Construction			
421	Miscellaneous Nonoperating Income			
421.1	Gain on Disposition of Property			
	TOTAL Other Income			
	Other Income Deductions			
421.2	Loss on Disposition of Property			
425	Miscellaneous Amortization			
426.1 - 426.5	Miscellaneous Income Deductions			
	TOTAL Other Income Deductions			
	Taxes Applic. to Other Income and Deductions			
408.2	Taxes Other Than Income Taxes			
409.2	Income Taxes - Federal			

(Continued on next page)

Company Northern States Power Company

(Minnesota Gas Jurisdiction)
For Calendar Year 2015

MINNESOTA DEPARTMENT OF COMMERCE

STATEMENT OF INCOME FOR THE YEAR

Acct. No.	ACCOUNT NAME	1 Current Year Normalized for Weather Where Appropriate	2 Current Year Unnormalized Data	3 Projected Year Data Normalized for Weather
	OTHER INCOME AND DEDUCTIONS			
409.2	Income Taxes - Other			
410.2	Provision for Deferred Income Taxes			
411.2	(Less) Provision for Deferred Income Taxes - Cr.			
411.5	Investment Tax Credit Adj. - Net			
420	(Less) Investment Tax Credits			
	TOTAL Taxes on Other Income and Deductions			
	Net Other Income and Deductions			
	INTEREST CHARGES			
427	Interest on Long-Term Debt	10,593	10,593	11,526
428	Amort. of Debt. Disc. and Expense			
428.1	Amortization of Loss on Reacquired Debt.			
429	(Less) Amort. of Premium on Debt-Credit			
429.1	(Less) Amort. of Gain on Reacquired Debt-Credit			
430	Interest on Debt to Assoc. Companies			
431	Other Interest Expense			
432	(Less) Allowance for Borrowed Funds Used During Construction - Cr.	987	987	939
	Net Interest Charges	9,605	9,605	10,587
	Income Before Extraordinary Items	24,124	21,083	23,758
	EXTRORDINARY ITEMS			
434	Extraordinary Income			
435	(Less) Extraordinary Deductions			
	Net Extraordinary Items			
409.3	Income Taxes - Federal and Other			
	Extraordinary Items After Taxes			

Company Northern States Power Company

(Minnesota Gas Jurisdiction)
For Calendar Year 2015

MINNESOTA DEPARTMENT OF COMMERCE

OPERATION AND MAINTENANCE EXPENSES

ACCOUNT NUMBER	**ACCOUNT NAME**	OPERATION **a**	MAINTENANCE **b**	TOTAL **c**
700-798	Production			1,814
799-813	Natural Gas Supply			249,457
814-847	Natural Gas Storage			3,040
850-870	Transmission			47,893
871-895	Distribution			31,862
901-905	Customer Accounts			11,275
906-910	Customer Service & Information			13,522
911-917	Sales			7
920-935	Administration & Gen.			19,987
	Total Operations & Maintenance Expense			
	Shared Services*			378,858
	Conservation Improvement Plan (CIP) Expense**			11,853 (1)

* Shared Services represents funds which compensate non-regulated organizations(s) within the overall corporate structure for services rendered to its regulated gas utility subsidiary. The value on this line is included on the Total Operations & Maintenance Expense Line. Describe on page "33 extra" how the share of shared services is computed.

** The value on this line is included in one or more of the account categories above. Please indicate which category(ies) includes these CIP expenses.
(1) Included in Customer Service and Information.

Company Northern States Power Company

(Minnesota Gas Jurisdiction)
For Calendar Year 2015

MINNESOTA DEPARTMENT OF COMMERCE

RATE OF RETURN ON RATE BASE AND ON COMMON EQUITY

1 Rates of return both on rate base and to common equity must be computed from actual information from the books and records for the reporting year.

2 Use beginning and end of the year account balances to compute average plant-in-service and depreciation reserve balances. Use 13-month end account balances to compute the average balances for other rate base components. ASSUME a -0- CASH WORKING CAPITAL REQUIREMENT IN RATE BASE.

3 Use the average of twelve monthly balances for the Debt, average of thirteen monthly balances for the Preferred Stock and also the Common Equity components of the Capital Structure.

4 Use space below to show computations of all averages used for rate base and capitalization components.

NET OPERATING INCOME AND RETURN ON RATE BASE

		1 Current Year Normalized for Weather		2 Current Year Unnormalized Data		3 Projected Year Data Normalized for Weather	
1	Revenues	493,142	*	487,955	*	472,782	*
2	Expenses	459,413	*	457,267	*	438,437	*
3	Net Operating Income	33,729	*	30,688	*	34,345	*
4	Allowance For Funds Used During Construction	987		987		939	
5	Total Available for Return	34,716	*	31,676	*	35,284	*
6	AVERAGE RATE BASE	470,779		470,779		514,572	
7	RATE OF RETURN ON RATE BASE Line 5/Line 6	7.3700%	*	6.7300%	*	6.8600%	*

* Including CIP Incentives in Jurisdictional Earnings would result in the following line changes:

	Current Year Normalized	Current Year Unnormalized	Projected Year
Line 1 Revenues	492,629	487,443	488,685
Line 2 Expenses	455,614	453,469	452,344
Line 3 Net Operating Income	37,015	33,974	36,342
Line 5 Total Available for Return	38,002	34,962	37,281
Line 7 Rate of Return on Rate Base	8.0700%	7.4300%	7.2500%

(continued

Company **Northern States Power Company**

Page G-34A

Gas Utility
Average Year Rate Base - Minnesota Jurisdiction
For Year Ended 12/31/15
($000s)

		Beginning of Year	End of Year	Average
Plant				
	Production	$16,892	$17,192	$17,042
	Storage	47,252	47,228	47,240
	Transmission	72,353	75,388	73,871
	Distribution	852,729	912,689	882,709
	General	45,516	47,454	46,485
	Common	58,283	64,266	61,275
	Total	$1,093,026	$1,164,217	$1,128,622
Reserve				
	Production	$13,117	$13,735	$13,426
	Storage	26,363	28,159	27,261
	Transmission	27,460	25,996	26,728
	Distribution	399,801	417,139	408,470
	General	23,406	25,241	24,323
	Common	33,313	36,870	35,091
	Total	$523,459	$547,140	$535,300
Accumulated Deferred Taxes		$154,544	$169,356	$161,950
Working Capital				
	Gas in Storage (1)			27,935
	Materials & Supplies (1)			763
	Prepaids & Other (1)			(384)
	Total			$28,314
CWIP				$12,187
Non-Plant Assets & Liabilities				($1,093)
Differences Due To Rounding				($1)
Average Rate Base				$470,779

Notes
(1) Fuel, Materials & Supplies, and Prepaids & Other, in this section, are calculated using a 13-month average to be consistent with rate case filings.

Source
MN Juris COSS

Company **Northern States Power Company**
Gas Utility
Net Operating Loss Related Deferred Tax Asset Balances - Minnesota Jurisdiction
For Year Ended 12/31/15
($000s)

	2014 Annual Report	Net Change (2)	2015 Annual Report
EOY Unused Deduction Balance	25,176	(25,176)	0
Deferred Tax Asset - Unused Deductions	10,276	(10,271)	4
Deferred Tax Asset - Unused Credits	0	0	0
Total (EOY Rate Base)	**10,276**	**(10,271)**	**4**

Notes

(1) Includes current period activity as allocated to the Minnesota jurisdiction.

Source
MN Juris NOL Worksheet

Company Northern States Power Company

(Minnesota Gas Jurisdiction)
For Calendar Year 2015

MINNESOTA DEPARTMENT OF COMMERCE

RATE OF RETURN ON RATE BASE AND ON COMMON EQUITY

CURRENT YEAR CAPITALIZATION

		Amount (a)	Percent of Total (b)	Cost (c)	Weighted Average (d)
8	Debt	4,349,580	47.2400%	5.78000%	2.2500%
9	Preferred Stock				
10	Common Equity	4,856,662	52.7600%	10.0900%	5.3200%
11	Total Capitalization	9,206,242	100%		

RETURN ON COMMON EQUITY FOR CURRENT YEAR NORMALIZED FOR WEATHER **

Line 7, Column 1 - (Line 8, Column (d) + Line 9, Column (d))
Line 10, Column (b) — 9.71%

PROJECTED YEAR CAPITALIZATION

		Amount (a)	Percent of Total (b)	Cost (c)	Weighted Average (d)
12	Debt	4,744,138	47.5000%	6.6500%	2.2400%
13	Preferred Stock				
14	Common Equity	5,243,944	52.5000%	10.0900%	5.3000%
15	Total Capitalization	9,988,082	100%		

RETURN ON COMMON EQUITY FOR PROJECTED YEAR **

Line 7, Column 3 - (Line 12, Column (d) + Line 13, Column (d))
Line 14, Column (b) — 8.79% *

** Including CIP Incentives in Jurisdictional Earnings would result in the following line changes:

Return on Common Equity for Current Year	11.04%
Return on Common Equity for Projected	9.53%

Company Northern States Power Company

SALES AND DEGREE DAYS DATA
WEATHER NORMALIZED

(Minnesota Gas Jurisdiction)
For Calendar Year 2015

MINNESOTA DEPARTMENT OF COMMERCE

NOTE: Companies are required to provide sales and other data based on the categories listed below. Additional space below for descriptions of calculations used as necessary.

A) Actual Monthly Sales corrected for billing Errors (Dkt)
B) Revenue Corresponding to Sales
C) Number of Customers (average per month)
D) Heating Degree Days Matched to Sales Data

Rate Schedule Name		JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC		TOTAL
Residential With Heating	A)	6,932,929	5,969,574	4,575,372	2,584,521	1,116,413	700,955	643,313	649,854	865,523	1,811,976	3,794,033	6,005,871	A)	35,650,334
	B)	53,920,657	56,695,912	37,131,071	18,106,849	10,384,340	8,029,165	7,845,707	7,948,058	8,320,651	13,388,938	24,143,057	35,602,168	B)	281,516,573
	C)	412,263	412,589	412,997	413,096	412,970	412,573	412,167	412,253	412,639	413,975	414,582	415,103	C)	413,101
	D)													D)	
Residential Without Heating	A)													A)	
	B)													B)	
	C)													C)	
	D)	1,423	1,497	907	451	198	10	3	15	61	409	714	1,073	D)	6,759
Commercial	A)	3,718,464	3,225,823	2,642,849	1,303,020	787,165	394,676	408,614	425,355	550,638	1,123,362	2,177,190	3,378,699	A)	20,135,857
	B)	25,935,299	27,094,736	18,668,883	7,293,492	5,222,628	3,256,868	3,376,606	3,571,177	3,654,031	6,401,556	11,467,722	16,692,520	B)	132,635,517
	C)	34,240	34,286	34,311	34,312	34,256	34,230	34,197	34,188	34,217	34,283	34,331	34,400	C)	34,271
	D)													D)	
Industrial and Mining	A)	358,406	309,421	347,100	195,231	174,889	151,328	165,170	149,648	162,055	211,002	268,289	268,440	A)	2,760,979
	B)	2,213,020	1,943,494	2,199,744	1,157,757	1,095,719	1,031,356	1,070,842	1,023,774	969,421	1,167,955	1,332,058	1,367,267	B)	16,572,406
	C)	133	133	133	133	133	133	132	132	133	135	135	136	C)	133
	D)													D)	
Small Interruptible	A)	1,094,186	1,226,987	1,369,893	849,719	509,272	607,101	386,515	466,053	525,824	850,913	1,154,863	1,097,779	A)	10,139,106
	B)	5,818,757	7,642,862	7,760,701	3,683,983	2,023,760	2,805,307	1,786,599	2,202,949	2,135,130	3,430,509	4,329,274	4,028,809	B)	47,648,640
	C)	420	419	418	419	419	418	418	397	397	397	397	397	C)	410
	D)													D)	

Additional space for page 36

Company: Northern States Power Company

(Minnesota Gas Jurisdiction)
For Calendar Year 2015

SALES AND DEGREE DAYS DATA
WEATHER NORMALIZED

Rate Schedule Name

A) Actual Monthly Sales corrected for billing Errors (Dkt)
B) Revenue Corresponding to Sales
C) Number of Customers (average per month)
D) Heating Degree Days Matched to Sales Data

Rate Schedule Name		JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC		TOTAL
	A)	17,986	4,702	12,933	9,165	10,857	3,000	7,990	11,546	3,757	2,657	3,622	6,474	A)	94,691
Interdepartmental	B)	100,609	29,829	279,296	43,665	46,211	16,149	36,675	52,983	17,145	13,055	16,695	33,554	B)	685,865
	C)													C)	
	D)													D)	
	A)	1,882,620	1,842,030	2,723,129	2,106,663	1,281,461	1,912,277	2,575,105	2,037,133	2,351,942	1,832,542	2,048,193	2,927,365	A)	25,520,459
Transportation	B)	888,821	805,802	874,685	840,300	706,440	778,706	938,920	798,846	845,947	815,453	881,447	1,109,413	B)	10,284,779
	C)	18	18	18	18	18	18	19	19	19	19	19	19	C)	19
	D)													D)	
Total	A)	14,004,592	12,578,538	11,671,275	7,048,319	3,880,057	3,769,338	4,186,707	3,739,589	4,459,739	5,832,453	9,446,190	13,684,629	A)	94,301,426
Retail	B)	88,877,163	94,212,635	66,914,380	31,126,046	19,479,098	15,917,552	15,055,348	15,597,786	15,942,326	25,217,465	42,170,253	58,833,730	B)	489,343,781
	C)	447,074	447,445	447,877	447,978	447,796	447,372	446,933	446,989	447,405	448,809	449,464	450,055	C)	447,933
	D)													D)	
	A)													A)	
Other	B)	-623,601	-155,835	621,023	-173,094	-4,093	801,604	67,185	144,044	476,039	146,775	-383,268	2,368,856	B)	3,285,636
	C)													C)	
	D)													D)	
TOTAL	A)	14,004,592	12,578,538	11,671,275	7,048,319	3,880,057	3,769,338	4,186,707	3,739,589	4,459,739	5,832,453	9,446,190	13,684,629	A)	94,301,426
	B)	88,253,562	94,056,801	67,535,403	30,952,952	19,475,004	16,719,156	15,122,533	15,741,830	16,418,366	25,364,239	41,786,985	61,202,585	B)	492,629,417
	C)	447,074	447,445	447,877	447,978	447,796	447,372	446,933	446,989	447,405	448,809	449,464	450,055	C)	447,933
	D)													D)	

Note: Please complete this form to the extent possible. Use space below for descriptions of calculations used.

Company Northern States Power Company

MINNESOTA DEPARTMENT OF COMMERCE

SALES AND DEGREE DAYS DATA

(Minnesota Gas Jurisdiction)

DATA ACTUAL

For Calendar Year 2015

NOTE: Companies are required to provide sales and other data based on the categories listed below. Additional space below or descriptions of calculations used as necessary.

A) Actual Monthly Sales corrected for billing Errors (Dkt)
B) Revenue Corresponding to Sales
C) Number of Customers (average per month)
D) Heating Degree Days Matched to Sales Data

Rate Schedule Name		JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC		TOTAL
Residential With Heating	A)	6,514,817	7,118,580	4,254,445	2,276,510	1,055,855	649,193	643,313	649,854	784,233	1,608,187	3,151,340	4,822,759	A)	33,529,085
	B)	53,165,242	58,771,855	36,551,242	17,550,355	10,274,928	7,935,645	7,845,707	7,948,058	8,173,782	13,020,745	22,981,885	33,464,604	B)	277,684,049
	C)	412,263	412,589	412,997	413,096	412,970	412,573	412,167	412,253	412,639	413,975	414,582	415,103	C)	413,101
	D)													D)	
Residential Without Heating	A)													A)	
	B)													B)	
	C)													C)	
	D)	1,423	1,497	907	451	198	10	3	15	61	409	714	1,073	D)	6,759
Commercial	A)	3,511,232	3,809,469	2,477,904	1,149,796	758,456	370,394	408,614	425,355	514,929	1,027,834	1,849,387	2,747,885	A)	19,051,255
	B)	25,694,676	27,772,424	18,477,360	7,115,580	5,189,292	3,228,674	3,376,606	3,571,177	3,612,568	6,290,635	11,087,101	15,960,064	B)	131,376,157
	C)	34,240	34,286	34,311	34,312	34,256	34,230	34,197	34,188	34,217	34,283	34,331	34,400	C)	34,271
	D)													D)	
Industrial and Mining	A)	358,406	309,421	347,100	195,231	174,889	151,328	165,170	149,648	162,055	211,002	268,289	268,440	A)	2,760,979
	B)	2,213,020	1,943,494	2,199,744	1,157,757	1,095,719	1,031,356	1,070,842	1,023,774	969,421	1,167,955	1,332,058	1,367,267	B)	16,572,406
	C)	133	133	133	133	133	133	132	132	133	135	135	136	C)	133
	D)													D)	
Small Interruptible	A)	1,055,226	1,333,533	1,346,180	833,413	507,964	607,101	386,515	466,053	525,824	832,990	1,082,977	981,006	A)	9,958,782
	B)	5,798,384	7,698,577	7,748,301	3,675,456	2,023,076	2,805,307	1,786,599	2,202,949	2,135,130	3,421,136	4,291,683	3,967,745	B)	47,554,343
	C)	420	419	418	419	419	418	418	397	397	397	397	397	C)	410
	D)													D)	

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Company: Northern States Power Company

(Minnesota Gas Jurisdiction)
For Calendar Year 2015

MINNESOTA DEPARTMENT OF COMMERCE

SALES AND DEGREE DAYS DATA
DATA ACTUAL

NOTE: Companies are required to provide sales and other data based on the categories listed below. Additional space below for descriptions of calculations used as necessary.

Rate Schedule Name

A) Actual Monthly Sales corrected for billing Errors (Dkt)
B) Revenue Corresponding to Sales
C) Number of Customers (average per month)
D) Heating Degree Days Matched to Sales Data

Rate Schedule Name		JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC		TOTAL
Interdepartmental	A)	17,986	4,702	12,933	9,165	10,857	3,000	7,990	11,546	3,757	2,657	3,622	6,474	A)	94,691
	B)	100,609	29,829	279,296	43,665	46,211	16,149	36,675	52,983	17,145	13,055	16,695	33,554	B)	685,865
	C)													C)	
	D)													D)	
Transportation	A)	1,882,620	1,842,030	2,723,129	2,106,663	1,281,461	1,912,277	2,575,105	2,037,133	2,351,942	1,832,542	2,048,193	2,927,365	A)	25,520,459
	B)	888,821	805,802	874,685	840,300	706,440	778,706	938,920	798,846	845,947	815,453	881,447	1,109,413	B)	10,284,779
	C)	18	18	18	18	18	18	19	19	19	19	19	19	C)	19
	D)													D)	
Total Retail	A)	13,340,287	14,417,735	11,161,689	6,570,778	3,789,481	3,693,294	4,186,707	3,739,589	4,342,740	5,515,212	8,403,809	11,753,930	A)	90,915,251
	B)	87,860,751	97,021,982	66,130,628	30,383,113	19,335,666	15,795,838	15,055,348	15,597,786	15,753,994	24,728,979	40,590,869	55,902,646	B)	484,157,600
	C)	447,074	447,445	447,877	447,978	447,796	447,372	446,933	446,989	447,405	448,809	449,464	450,055	C)	447,933
	D)													D)	
Other	A)													A)	
	B)	-623,601	-155,835	621,023	-173,094	-4,093	801,604	67,185	144,044	476,039	146,775	-383,268	2,368,856	B)	3,285,636
	C)													C)	
	D)													D)	
TOTAL	A)	13,340,287	14,417,735	11,161,689	6,570,778	3,789,481	3,693,294	4,186,707	3,739,589	4,342,740	5,515,212	8,403,809	11,753,930	A)	90,915,251
	B)	87,237,151	96,866,147	66,751,651	30,210,019	19,331,573	16,597,442	15,122,533	15,741,830	16,230,033	24,875,754	40,207,601	58,271,502	B)	487,443,236
	C)	447,074	447,445	447,877	447,978	447,796	447,372	446,933	446,989	447,405	448,809	449,464	450,055	C)	447,933
	D)													D)	

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Company Northern States Power Company

(Minnesota Gas Jurisdiction)
For Calendar Year 2015

MINNESOTA DEPARTMENT OF COMMERCE

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1 This schedule is intended to give particulars of the combined prepaid and accrued tax accounts and to show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the material on which the tax was levied was charged. If the actual or estimated amounts of such taxes are known, they should be shown as a footnote and designated whether estimated or actual amounts.

2 Taxes, paid during the year and charged direct to final accounts, that is, not charged to prepaid or accrued taxes, should be included in the schedule. Enter the amounts both in columns (c) and (e). The balancing of the schedule is not affected by the inclusion of these taxes.

3 Taxes charged during the year, column (d), include taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b) amounts credited to prepaid taxes for proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged directly to operations or accounts other than accrued and prepaid tax accounts.

4 The aggregate of each kind of tax should be listed under the appropriate heading of “Federal,” State,” “Local” in such a manner that the total tax for each State and for all subdivisions can readily be ascertained.

5 If any tax covers more than one year, the required information of all columns should be shown separately for each tax year. When the amounts accrued pertain to other than the current year, show by footnote for each year whether the tax return has been audited by the Internal Revenue Service and furnish particulars for any adjustments, in total (debit or credit), that have been made to Account 236, Taxes accrued, due to any such audits.

6 Enter all adjustments by parentheses.

7 Do not include in this schedule entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.

8 The accounts to which taxes charged were distributed should be shown in columns (i) to (o). Show both the utility department and number of account charged. For taxes charged to utility plant, show the number of the appropriate balance sheet, plant account or subaccount.

9 For any tax which it was necessary to apportion to more than one utility department or account, state in a footnote the basis of apportioning such tax.

Company Northern States Power Company

(Minnesota Gas Jurisdiction)
For Calendar Year 2015

MINNESOTA DEPARTMENT OF COMMERCE

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

	B.O.Y BALANCES					E.O.Y. BALANCES	
	TAXES ACCRUED **(a)**	PREPAID TAXES **(b)**	TAXES CHARGED DURING YEAR **(c)**	TAXES PAID DURING YEAR **(d)**	ADJUSTMENTS **(e)**	TAXES ACCRUED (ACCOUNT 236) **(f)**	PREPAID TAXES (INCL. IN ACCT.165) **(g)**
FEDERAL INCOME							
UNEMPLOY							
FICA							
OTHER							
STATE PROPERTY							
INCOME							
UNEMPLOY							
OTHER							
LOCAL GROSS							
FRANCHISE TAX							
OTHER							

Continued on next page

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Company Northern States Power Company

(Minnesota Gas Jurisdiction)
For Calendar Year 2015

MINNESOTA DEPARTMENT OF COMMERCE

TAXES ACCRUED, PREPAID, AND CHARGED DURING YEAR

DISTRIBUTION OF TAXES CHARGED (Show utility department where applicable and account charged.)

	ELECTRIC ACCT. 408.1 & 409.1 (h)	OTHER DEPTS. ACCT. 408.1 & 409.1 (i)	OTHER INC. & DED'N. ACCTS 408.2 & 409.2 (j)	EXTRAORDINARY ITEMS, ACCT. 409.3 (k)	OTHER UTILITY OPER INCOME ACCTS. 408.1 & 409.1 (l)	ADJ. TO RET. EARNINGS ACCT. 439 (m)
FEDERAL						
INCOME						
UNEMPLOY						
FICA						
OTHER						
STATE						
PROPERTY						
INCOME						
UNEMPLOY						
OTHER						
LOCAL						
GROSS						
FRANCHISE TAX						
OTHER						

See Page G-42A

Company Northern States Power Company

MINNESOTA DEPARTMENT OF COMMERCE

(Minnesota Gas Jurisdiction)
For Calendar Year 2015

Taxes Charged During The Year
(Minnesota Jurisdiction)

($000's)

Federal Income Taxes	$915
State Income Taxes	284
Taxes other than Income Taxes	
-Property Taxes	17,533
-Gross Earnings	0
-Payroll	2,269
Total Other Than Income Taxes	$19,802
Deferred Income Tax + ITC Flow through	11,822
TOTAL TAXES	$32,824

The detail of taxes requested on this form presents a problem for a multi-utility, multi-jurisdictional Company such as NSP. The Minnesota jurisdictional current income taxes are determined using the operating revenues and expenses directly assigned or allocated to Minnesota to arrive at the taxable income and applying the federal and state income tax rates. This method does not identify taxes accrued or taxes paid on a jurisdictional basis. It calculates the current tax liability only.

The payroll taxes (FICA, Employer's Excise, Federal and State Unemployment) are assigned or allocated to utility and jurisdictional in total, therefore, the jurisdictional information is not available by type of payroll tax as requested.

Company Northern States Power Company

ALLOCATION STATISTICS *

(Minnesota Gas Jurisdiction)
For Calendar Year 2015

Allocation Use and Basis: Describe the meaning of the allocations, show the formula, and define all numbers used in the formula. Please efile a separate document with this report for additional information.

CURRENT YEAR STATISTICS

		REFERENCE (WHERE USED) Pg	Ln	Col	TOTAL UTILITY (a)	MINN JURIS (b)	MINN % OF TOTAL (c)	LAST YR MINN % OF TOTAL (d)	CHANGE FROM LAST YEAR (e)
1									
2	Production (LPG) & Storage (LNG) Factors - MN Jurisdiction Mcf				809,671	715,945	88.42420%	88.94820%	-0.52400%
3									
4	Used to allocate Plant & Plant Related items								
5	between MN & ND Jurisdictions: Factor is based on Projected Design Day Requirements								
6									
7									
8									
9									
10	General Plant System Load Dispatching MN Jurisdiction - Sales Mcf				101,706,668	90,915,251			
11	MN Jurisdiction - Design Day Mcf				809,671	715,945	88.90690%	88.82740%	0.07950%
12									
13									
14									
15									

* Indicate allocation statistics which have changed during the year using an asterisk.

Continued on next page

Company Northern States Power Company

(Minnesota Gas Jurisdiction)
For Calendar Year 2015

ALLOCATION STATISTICS *

CURRENT YEAR STATISTICS

Allocation Use and Basis: Describe the meaning of the allocations, show the formula, and define all numbers used in the formula. Please efile a separate document with this report for additional information.		REFERENCE (WHERE USED) Pg	Ln	Col	TOTAL UTILITY (a)	MINN JURIS (b)	MINN % OF TOTAL (c)	LAST YR MINN % OF TOTAL (d)	CHANGE FROM LAST YEAR (e)
16	Customers:								
17	Average Customers MN Jurisdiction								
18	Divided by Average Customers								
19	Total Company								
20	447,933 / 500,894 = 89.4267				500,894	447,933	89.42670%	89.65780%	-0.23110%
21									
22									
23									
24									
25									
26									
27									
28									
29									
30									

* Indicate allocation statistics which have changed during the year, using an asterisk.

Company Northern States Power Company

(Minnesota Gas Jurisdiction)
For Calendar Year 2015

MINNESOTA DEPARTMENT OF COMMERCE

ATTESTATION

State of Minnesota)
)
County of Hennepin)

The foregoing must be attested by an officer of the Utility.

Chris Clark certifies that
(The name of the attestor)

he or she is President
(The official title of the attestor)

of Northern States Power Company
(The title or name of the respondent)

on oath say that the report to the Minnesota Department of Commerce for the **Calendar Year 2015** has been prepared under my direction from the books, papers and records of the above-named respondent; that I have carefully examined the reprot and declare it to be a correct statement of the business and affairs of the above-named respondent in respect to each and every matter therein set forth.

(Electronic Signature of Attestor)

612-215-4593
Phone Number

CERTIFICATE OF SERVICE

I, Lynnette Sweet, hereby certify that I have this day served copies or summaries of the foregoing documents on the attached list(s) of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States Mail at Minneapolis, Minnesota

xx electronic filing

Docket No. G002/M-16-891

Dated this 13th day of March 2017

/s/

____
Lynnette Sweet

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