MINNESOTA DEPARTMENT OF COMMERCE

85 7TH PLACE EAST, SUITE 280
SAINT PAUL, MINNESOTA 55101-2198
MN.GOV/COMMERCE
651.539.1600 FAX: 651.539.1574
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March 1, 2017 **PUBLIC DOCUMENT**

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

RE: **PUBLIC Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. G002/M-16-891

Dear Mr. Wolf:

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

> In the Matter of the Petition of Northern States Power Company, doing business as Xcel Energy, for Approval of a Gas Utilities Infrastructure Cost Rider True-up Report for 2016, Revenue Requirements for 2017, and Revised Adjustment Factors.

The Petition was filed on November 1, 2016 by:

> Amy Liberkowski
> Manager, Regulatory Analysis
> Xcel Energy
> 414 Nicollet Mall, 7th Floor
> Minneapolis, Minnesota 55401

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

The Department is available to answer any questions the Commission may have.

Sincerely,

/s/ ADAM J. HEINEN	/s/ JOHN KUNDERT
Rates Analyst	Financial Analyst
651-539-1825	651-539-1740

/lt
Attachment

MINNESOTA DEPARTMENT OF COMMERCE

PUBLIC DOCUMENT

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

PUBLIC COMMENTS OF THE MINNESOTA DEPARTMENT OF COMMERCE

DOCKET NO. G002/M-16-891

I. BACKGROUND

On August 1, 2014, Northern States Power Company, d/b/a Xcel Energy (Xcel or the Company), filed a Petition requesting approval of a Gas Utility Infrastructure Cost (GUIC) Rider pursuant to Minn. Stat. 216B.1635. This request was the first proposal for rate treatment under Minn. Stat. 216B.1635. On January 27, 2015, the Minnesota Public Utilities Commission (Commission) issued an *Order Approving Rider With Modifications* (2015 GUIC Order) in Docket No. G002/M-14-336 (Docket No. 14-336) approving Xcel's proposed GUIC Rider, rate-adjustment factors and tariff sheets with certain modifications. The Commission also required Xcel to submit information on the rate of return for the upcoming year 60 days in advance of its 2015 GUIC filing. Xcel filed this information on September 2, 2015 in anticipation of its 2015 GUIC filing.

On November 1, 2016, the Company filed its *Petition* requesting approval of a GUIC Rider True-Up Report for 2016, revenue requirements for 2017, and revised adjustment factors.

II. SUMMARY OF PETITION

In previous orders, the Commission approved recovery of a number of projects under the GUIC Statute (Minn. Stat. 216B.1635). Xcel developed transmission- and distribution-integrity management programs (TIMP and DIMP, respectively). In the TIMP category, the following initiatives are underway or planned:

- **Transmission pipeline assessments,** including in-line inspection, pressure testimony, and direct assessment;
- **East Metro Pipeline Replacement Project,** to replace aging high-pressure transmission pipeline running through the urban corridor between Saint Paul and Roseville with new pipeline with a standard 20-inch diameter;
- **Automatic-shutoff and remote-controlled valve installation,** allows more expedient gas shutoff in an emergency; and
- **Programmatic Replacement/MAOP Remediation**, program targets capital-intensive repairs or replacement efforts needed on transmission pipelines that have been assessed for asset health and condition in prior years.

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

- **Poor-performing main and service-line replacement,** entails identifying high-risk pipeline segments and prioritizing their replacement in concert with city and county road maintenance;
- **Intermediate-pressure line assessments,** determine the health and condition of medium-sized distribution pipelines,
- **Distribution-valve replacements,** maintain Xcel's ability to isolate sections of the system in case of an emergency;
- **Pipeline data gathering,** researching hard-copy records and converting this information to into its enterprise Geographic Information System (GIS) program; and
- **Sewer and gas line conflict-remediation program,** identify and correct situations where natural gas lines intersect with sewer lines.

Xcel proposed to recover its 2017 annual revenue requirements and its 2016 true-up carryover balance, less its 2016 revenue collections.[1] A summary of the Company's proposed GUIC revenue requirements is provided in Table 1:

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[1] A one-paragraph *Summary of Filing* is attached to the *Petition* pursuant to Minnesota Rule 7829.1300, subp. 1.

Table 1: TIMP and DIMP Expenses

Project	2017 Capital ($ Millions)	2017 O&M ($ Millions)
TIMP		
East Metro Pipeline Replacement	$0.00	$0.00
Transmission Pipeline Assessments	$1.61	$1.30
ASV/RCV	$0.90	$0.00
Programmatic Replacement/MAOP Remediation	$2.91	$0.00
Total TIMP	$5.42	$1.30
Total TIMP Incremental Revenue Requirements	$7.86	$1.15
DIMP		
Poor Performing Main Replacements	$11.03	$0.24
Poor Performing Services Replacements	$6.90	$0.04
Intermediate Pressure Line Assessments	$0.67	$0.30
Distribution Value Replacement	$0.72	$0.00
Sewer & Gas Line Conflict Investigation	$0.00	$3.50
Federal Code Mitigation	$0.20	$0.47
Total DIMP	$19.52	$4.55
Total DIMP Incremental Revenue Requirements	$4.14	$4.55
O&M in Base Rates		(0.48)
Pro-rated ADIT		0.11
Total Revenue Requirements	$12.00	5.33
5-Year Amortization of Deferred Costs	$0.82 (TIMP) $3.73 (DIMP) $4.55 (Total)	
Total 2016 Revenue Requirements Combined before True Up	$21.88	
True-Up Carryover from 2016	$0.26	
GUIC Total 2017 Revenue Requirements	$22.14	

Specifically, the revenue requirements through December 2017 total $22,138,854.

Xcel proposed an implementation data of April 1, 2017 for the proposed factors.[2] If the Commission is unable to act on this *Petition* in time for rates to become effective April 1, the Company requested to calculate the final rate adjustment factors to recover the remaining 2017 revenue requirements over the remaining months through March 31, 2018; in such case, Xcel would provide the rates as part of a compliance filing after the Commission's Order if the *Petition* is approved.

[2] *Petition,* Page 7.

Xcel proposed to allocate the revenue requirements within the GUIC Rider to its various customer classes in the same manner as revenue responsibilities were apportioned in its most recent natural gas rate case,[3] consistent with the Commission's 2015 and 2016 GUIC orders.[4] The Minnesota Department of Commerce (Department) reviewed Xcel's allocation of revenue responsibility and it agrees with using the figures approved in Xcel's most recent gas general rate case. Proposed class factors were calculated by dividing the class revenue responsibility by the forecasted Minnesota sales for the recovery period and include the GUIC Adjustment Factor as part of the Resource Adjustment line on customer bills.[5] The Company's approach yields the following GUIC rate adjustment factors for 2017:

Table 2: 2017 Adjustment Factors
(Dollars per therm)

	Current 2016 Factors	Proposed 2017 Factors
Residential	$0.010922	$0.041689
Commercial Firm	$0.006110	$0.023070
Commercial Demand Billed	$0.005274	$0.017177
Interruptible	$0.003860	$0.012162
Transportation	$0.001570	$0.004639

The figures in Table 2 above can be used to calculate that the proposed 2017 adjustment factors are between approximately 195 percent greater for the Transportation rate class than in 2016, with a proposed 280 percent increase for the Residential rate class over the current factors. Under the proposed adjustment factor, the average bill impact for a typical residential customer would be $2.95 per month or about 1.2 percent of the total bill, including recovery of gas costs. Focusing only on recovery of non-gas costs, the bill impacts associated with the GUIC rider would result in a bill impact for a typical residential customer of approximately 8.68 percent. The proposed factor calculations assume that the current factors are recovered through March 31, 2017 and the proposed factors become effective April 1, 2017.

III. DEPARTMENT ANALYSIS

A. STATUTORY BACKGROUND

Generally, a public utility may not change its rates without undergoing a general rate case in which the Commission comprehensively reviews the utility's costs and revenues. However, the Legislature created exceptions to this general policy, allowing a utility to implement a rider with a rate-adjustment mechanism to expedite recovery of certain costs not reflected in the utility's current base rates.

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[3] Docket No. G002/GR-09-1153.
[4] January 27, 2015 *Order* in Docket No. G002/M-14-336 and August 18, 2016 *Order* in Docket No. G002/M-15-808.
[5] *Petition*, Page 32.

Minnesota Statute 216B.1635 allows utilities to seek rider recovery of gas utility infrastructure costs. Gas utility infrastructure costs are costs that are not included in the gas utility's rate base in its most recent general rate case, which the utility incurred from gas infrastructure projects involving (1) the replacement of natural gas facilities required by road construction or other public work by or on behalf of a government agency and (2) the replacement or modification of existing facilities required by a federal or state agency, including surveys, assessments, reassessment, and other work necessary to determine the need for replacement or modification of existing infrastructure.[6] The Department notes that the Commission interpreted this Statute in its January 27, 2015 *Order* in the 2014 GUIC docket that a gas infrastructure project is eligible for rider recovery under Minn. Stat. 216B.1635 if either subpart (1) or (2) are satisfied not both parts. Projects that constitute a "betterment" do not qualify for rider recovery unless the betterment is "based on" requirements by a political subdivision or a federal or state agency.[7] The Minnesota Office of Attorney General (OAG) provided extensive discussion and analysis regarding the issue of betterment in last year's filing. In the Commission's August 18, 2016 *Order*, the Commission determined that the Company's GUIC eligible projects are appropriate and do not represent a betterment.

A utility seeking approval of a GUIC Rider must file a petition with the Commission detailing the projects and costs proposed for recovery.[8] The utility must file sufficient information to satisfy the Commission regarding the reasonableness of the proposed gas utility infrastructure costs, including, but not limited to, the following :

- Project description and scope, estimated costs, and in-service date;
- The government entity ordering or requiring the project and the purpose for which the project is undertaken;
- A description of the estimated costs and salvage value, if any, associated with the existing infrastructure replaced or modified as a result of the project;
- A comparison of the utility's estimated costs and the actual costs incurred, including a description of the utility's efforts to ensure that the costs of the facilities are reasonable and prudently incurred;
- Calculations to establish that the rate adjustment is consistent with the terms of the rate schedule, including the proposed rate design and an explanation of why the proposed rate design is in the public interest;
- The magnitude and timing of any known future projects that the utility may seek to recover under the GUIC statue;
- The magnitude of the costs in relation to the utility's base revenue as approved by the Commission in the utility's most recent general rate case, exclusive of gas-purchase costs and transportation charges;
- The magnitude of the costs in relation to the utility's capital expenditures since its most recent general rate case; and

[6] Minn. Stat. 216B.1635, subd. 1(b), (c).
[7] Minn. Stat. 216B.1635, Subd. 1(b) (3).
[8] *Id.*, Subd. 2-3.

- The amount of time since the utility last filed a general rate case and the utility's reasons for seeking recovery outside of a general rate case.[9]

The Commission may approve a GUIC Rider if the costs proposed for recovery through the rider are prudently incurred and achieve gas facility improvements at the lowest reasonable and prudent costs to ratepayers.[10] Costs eligible for rider recovery include not only gas utility infrastructure costs but also a rate of return, income taxes on the rate of return, incremental property taxes, incremental depreciation expense, and any incremental operation and maintenance (O&M) costs.[11]

Xcel included a Compliance Matrix in its Attachment H for the filing requirements in Minn. Stat. 216B.1635, as well as in Docket Nos. G002/M-10-422 (Docket No. 10-422) and G002/M-12-248 (Docket No. 12-248). Upon review of the *Petition*, the Department concludes that the Company has sufficiently complied with the filing requirements.

B. O&M EXPENSES IN BASE RATES

The test year from Xcel's most recent natural gas rate case test year included TIMP O&M costs of $480,000. Further, no O&M costs were included in the test year for DIMP.[12] In its *Petition*, consistent with the Commission's decisions in the Company's past related deferred costs proceedings, Xcel removed from its 2017 GUIC Rider the TIMP O&M expenses allowed for recovery in its most recent rate case. As a result, the Company's 2017 annual revenue requirements in the GUIC Rider has been reduced by approximately $480,000 of O&M.

C. PROJECT ELIGIBILITY

Xcel's *Petition* includes projects previously approved for recovery in earlier GUIC filings. The Company does not propose new projects; however, Xcel does anticipate beginning work on its Programmatic Replacement/MAOP Remediation program. This program was discussed in previous filings, but 2017 represents the first year that costs will be incurred for this program. Since the projects included in the *Petition* have already been reviewed by the Commission, the Department concludes that the projects are eligible for GUIC recovery. However, as discussed in Section E below, the Department identified concerns with the cost levels proposed by Xcel.

D. 2016 PROJECT VARIANCES

In Xcel's *Petition*, the Company provided the TIMP projects costs approved in the 2016 GUIC Order.[13] In the Company's supplemental response to Department Information Request No. 5, Xcel provided actual 2016 costs.[14] Actual TIMP capital spending was $5.88 million, or

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[9] *Id.*, Subd. 4.
[10] *Id.,* Subd. 5.
[11] *Id.*, Subd. 4.
[12] January 24, 2013 Commission *Briefing Papers*, page 6, Docket No. 12-248.
[13] *Petition*, Page 23.
[14] Xcel provided a forecast of expected costs for 2016 in its initial *Petition*.

4.1 percent, less than forecasted costs of $6.13 million. Actual TIMP O&M costs exceeded the original forecast of expenses by $35,409. Xcel explained the variances, compared to its forecast through August 2016, on a project-by-project basis.[15]

In the Company's *Petition*, Page 23, the Company provided the same comparison for DIMP project costs. Actual DIMP capital costs in 2016 were $2.21 million, or 15 percent lower than forecasted costs of $2.60 million. Actual DIMP O&M costs in 2016 were $4.14 million, or 10.8 percent lower than forecasted costs of $4.64 million. Xcel explained the variances, compared to its forecast through August 2016, on a project-by-project basis.[16]

The Department reviewed the variances and the explanations provided in Xcel's *Petition*. Based on its review, the Department concludes that the variances are generally reasonable. However, the Department identified issues with Xcel's proposed cost recovery, as discussed below.

E. ISSUES IDENTIFIED

Through its review of the Company's *Petition*, the Department observed several issues with Xcel's proposal. These issues are discussed separately below.

1. Pro-rated Accumulated Deferred Income Taxes (ADIT)

Xcel included the effects of proration of its ADIT balances in its revenue calculations. The Company's prorated ADIT calculations are shown in Attachment P of its *Petition*. As shown in this attachment, Xcel's pro-rated ADIT calculations increased its annual revenue requirements in 2016 by $134,029 and by $108,767 in 2017.

The prorated ADIT issue stems from recently issued Private Letter Rulings (PLRs) from the Internal Revenue Service (IRS). According to these PLRs, the IRS is concerned that utilities may be violating tax normalization rules by passing back the benefits of accelerated depreciation (via an ADIT credit to rate base) to ratepayers too soon. IRS Section 1.167(l)(h)(6) defines the procedures a company must use to normalize the impact on rate making in a forward-looking test year if a company elects to use accelerated depreciation. This section stipulates that the monthly changes to the deferred taxes balance, as calculated by the company, must be prorated prior to computing the average of beginning and ending balances for ADIT.

The Department notes that there is a difference between prorating ADIT balances in riders as opposed to rate cases. Riders have subsequent true-up calculations whereas rate cases do not. In addition, rate cases have interim rates and interim rate refunds which riders do not.

The prorated ADIT issue has been discussed extensively in the following riders and rate cases; however, the issue remains largely unresolved to date:

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[15] *Petition*, Attachment B, pages 5-25.
[16] *Petition*, Attachment C, pages 3-32.

- OTP's 2015 ECR Rider (Docket No. E017/M-15-719). OTP first proposed to incorporate the effects of prorated ADIT in its 2015 ECR Rider. As explained in the Department's January 15, 2016 Reply Comments, OTP proposed to raise the annual revenue requirements by $55,000 due to the effects of proration. However, since OTP proposed to keep its current ECR Rider rate in effect, the Department concluded and the Commission agreed that this issue did not need to be addressed in that proceeding.[17]

- Xcel Energy's 2015 Renewable Energy Standards Rider (RES Rider) in Docket No. E002/M-15-805. Xcel energy proposed to incorporate the effects of ADIT proration in its 2015 RES Rider, which increased its annual revenue requirement by $38,754. The Department opposed Xcel's proposal to prorate its ADIT balances. However, for purposes of resolving the issue and not using limited state resources, the Department's alternative recommendation was to: 1) allow the prorated ADIT only for recovery of forecasted costs and, 2) require a true-up in the following year (once all amounts are historical/actual) by using actual non-prorated ADIT amounts. Finally, if Xcel continued to pursue this issue to the detriment of ratepayers, the Department recommended that the Commission consider either denying rider recovery or limiting rider recovery to historical costs, as both of these approaches would eliminate the need to prorate ADIT balances. This docket was heard at the Commission's January 26, 2017 Agenda meeting, where the Commission authorized RES recovery on then-historical 2016 actual costs.

- Xcel Energy's 2015 TCR Rider (Docket No. E002/M-15-891). Xcel Energy also proposed to incorporate the effects of prorated ADIT in its 2015 TCR Rider, which increased the annual revenue requirements by $150,830. Xcel's 2015 TCR Rider was based on forecasted calendar year 2016 figures. This docket was before the Commission on December 8, 2016. Since the 2016 calendar year was nearly complete, the Commission directed Xcel to refile its proposed annual revenue requirements using actual 2016 balances once they became known. This approach essentially eliminated the need for Xcel to prorate its ADIT balances for its 2015 TCR Rider purposes. In addition, the Commission directed the Department to work with Xcel to seek its own Private Letter Ruling from the IRS to determine the proper treatment of prorated ADIT balances in forecasted riders and subsequent rider true-ups. Xcel held one meeting with stakeholders on the Company's PLR request.

- Xcel Energy's 2015 Rate Case in Docket No. E002/GR-15-826. Xcel Energy proposed to incorporate the effects of prorated ADIT in its 2015 Rate Case, which increased its annual revenue requirements for 2016 through 2019 by $11,549,000. The Department recommended in its Direct Testimony an

[17] See Commission's March 9, 2016 Order in Docket No. E017/M-15-719.

adjustment to exclude prorated ADIT from the rate case. [18] However, since the parties entered into an aggregated financial settlement, specific decisions on individual financial issues were not determined. As a result, the issue remains unresolved.

- OTP's 2015 Rate Case in Docket No. E017/GR-15-1033. The prorated ADIT issue was also discussed at length in OTP's 2015 Rate Case. In order to resolve this complex issue, the DOC and OTP agreed to jointly seek a PLR from the IRS to determine the proper rate case treatment of prorated ADIT balances in OTP's forecasted test year and interim rates, including the interim rate refund. OTP's PLR request was filed with the IRS on December 29, 2016. A response from the IRS is expected later in 2017.

Since the current petition involves the use of a rider with forecasted figures, the Department notes that Xcel's forthcoming PLR for its 2015 TCR Rider could be used as a guide on how to treat the prorated ADIT issue in the instant proceeding. In the meantime, the Department recommends that the Commission approve Xcel's proposed ADIT proration for the forecasted year in the instant petition, subject to a true-up calculation in the following year using actual non-prorated ADIT amounts.

2. Sales Forecast

As noted in its *Petition*, the Company used forecasted sales values to calculate the adjustment factors that it will assess to ratepayers. The Department reviewed these sales values and observed that Xcel did not provide information or discussion of how these values were calculated. In its response to Department Information Request No. 10, Xcel provided its model outputs and spreadsheets illustrating its derivation of forecasted sales (Department Attachment 1). The Department reviewed these calculations and concludes that the Company's forecasting models are generally appropriate. However, the Department observed an area of concern regarding the Company's final determination of sales. As noted in the Company's response to Department Information Request No. 10, Xcel first estimated sales using its regression models. It then used a calendar month allocation adjustment to better match sales to historical trends and, finally, it applied a Demand-Side Management (DSM) adjustment to account for the impacts of conservation on expected sales.

The Department is concerned that the Company's approach with its sales forecast does not appear to be reasonable for several reasons. First, the decision to re-allocate forecasted sales to match historical monthly sales is inappropriate and adds an additional layer of complexity to the Company's sales estimates. The Department was unable to fully replicate the monthly re-allocation method. Second, it appears that the Company's forecasting adjustments result in lower forecasted sales for certain rate classes relative to the results of the regression models. Lower forecasted sales, all else being equal, will translate into higher rates for ratepayers. Third, the inclusion of a DSM adjustment as an ad hoc

[18] See Ms. Nancy's Campbell's June 14, 2016 Direct Testimony in Docket No. E002/GR-15-826, Page 23; \$6,483,000+\$1,896,000+1,813,000+1,357,000 = \$11,549,000 (for 2016 to 2019).

adjustment to the effects of energy conservation that is already in the data is inappropriate since it double-counts DSM. Moreover, during a short-term forecast horizon any additional response by ratepayers to potential DSM incentives or projects in the short-run (*e.g.,* 12-month period) is negligible. Thus, the likely level of additional DSM not already accounted for in the underlying historical data is also insignificant. Thus, the Department does not believe DSM should be modeled separately in the short-term forecast in this proceeding.

Thus, based on the issues identified above, the Department recommends that GUIC recovery rates be based on the Company's regression model results before monthly sales and DSM adjustments. The Department recommends that Xcel provide updated schedules reflecting this recommendation in its *Reply Comments*.

3. Replacement of New Equipment

Per the reporting requirements laid out in Minn. Stat. 216B.163, subd. 4 (2), Xcel provided detailed information regarding its individual TIMP and DIMP projects. The Department reviewed this information and determined that it was generally sufficient to analyze the reasonableness of the Company's costs, except that Xcel's initial *Petition* did not provide information regarding when the replaced pipe was originally placed in service.[19] Xcel provided additional information regarding replaced pipe in its response to Department Information Request No. 17 (Department Attachment 2). Based on its review of this discovery response, the Department observed that the Company replaced relatively new pipe on three occasions and was unable to identify the age of replaced pipe in many instances. The Department is not necessarily concerned with the instances where Xcel is unable to identify the age of the pipe since the corresponding addresses are likely associated with older installations (*e.g.,* 1950s); as such, the Department believes the costs associated with these work orders are not unreasonable. However, the Department is concerned regarding the costs associated with the three instances of newer pipe.

On February 17, 2017, the Department and Xcel met to discuss issues and concerns with the Company's filing. As part of this meeting, the Department requested additional clarification and discussion regarding the Company's response to Department Information Request No. 17. Subsequent to this meeting, Xcel supplemented its response to Department Information Request No. 17 (Department Attachment 3). In this supplemental response, Xcel explained that it reviewed its system in detail and determined that the three instances where newer pipe was replaced were reported in error, in addition to other projects being originally reported with the incorrect year of installation. In fact, these three instances involved pipe that was much older in vintage and comparable in age to other pipe that had been replaced.

Based on Xcel's supplemental information request response, the Department concludes that there is no issue regarding replacement of newer pipe. However, the Department is concerned that the Company had difficulty reporting the correct installation dates in its initial discovery response. The Department recommends that Xcel work to improve the

[19] *Petition*, Attachment C(1).

quality of its information request responses in future filings, and the Department will continue to monitor the age of pipe replaced and associated costs recovered through the GUIC.

4. Sewer Conflict Inspection Equipment

In early 2010, an incident occur on the Xcel system where a house was destroyed as the result of a sewer cleaning contractor hitting a natural gas main that had intersected the sewer line. This incident raised concerns that other sewer and gas line interactions existed on the Company's system and posed a safety concern. Xcel's decision to investigate and mitigate these issues was the genesis for the Company's original recovery of accelerated safety costs (Docket No. G002/M-10-422) which were then rolled into this Rider in the Commission's *Order* in Docket No. G002/M-14-366. Although the Department does not dispute the reasonableness of mitigating these conflicts, the Department did analyzed the Company's strategy regarding its procurement of resources associated with these projects. In particular, Xcel stated the following in its *Petition*:

> Only the camera inspection aspect of the program is outsourced. At present, the Company has neither the internal expertise nor the equipment available to perform this specialized aspect of the program. By outsourcing the inspections, the Company has spared ratepayers the cost of expensive, specialized equipment, and ensured that those with the expertise are conducting the investigations.

Xcel also stated the following regarding the costs associated with the sewer line mitigation program:[20]

> Between 2011 and 2015, the annual cost for the sewer and gas line conflict remediation program averaged $3.5 million. We anticipate that costs for inspections will continue at this level for the next few years. We plan to continue inspections at the historic level until such time that it is appropriate to modify the number of annual inspections. In part, the expenses of the program in the future will reflect the results of those inspections. Depending on the number of conflicts found, the Company will evaluate the associated level of risk and adjust the number of inspections as needed.

Given the length and cost associated with the sewer line mitigation program, the Department requested additional information regarding the Company's decision to outsource camera inspections. In its response to Department Information Request No. 6, Xcel explained that it has not conducted a cost/benefit analysis related to the decision to outsource this work (Department Attachment 4). The Company further stated that

[20] *Petition*, Page 30.

inspecting sewer lines for potential conflicts with natural gas lines is a unique activity that differs from normal activities associated with the installation, operations, and maintenance of a gas system. Finally, because of this uniqueness, the Company has not determined that investing in the ownership of the specialized equipment or training necessary to perform the work as practical.

The Department understands that camera inspection equipment are likely outside of the core business of a gas utility. However, the Department is troubled that the Company did not investigate the costs associated with procuring this equipment at the outset of the sewer line project. This concern is especially true after the issues with sewer line inspection became more extensive than projected and the ongoing annual costs associated with this program. Without a cost/benefit analysis, the Department is unable to determine whether ratepayers were assessed through the GUIC rider, and will be assessed into the future, the lowest reasonable cost associated with the sewer line inspection program. For example, if the costs of procuring video inspection equipment, relative to contracting for this equipment, were less expensive, the burden would be on the Company to explain why ratepayers should be charged costs greater than the cost of owning and operating inspection equipment. The Department recommends that Xcel provide a detailed analysis in *Reply Comments* comparing the costs of procuring video inspection equipment at the outset of, and each subsequent year until the present, the sewer line inspection plan relative to the expected costs of engaging contractors to complete this work.

5. Review of Software Costs

As noted in the Company's *Petition*, Xcel included software-related costs of approximately $2,073,000 in its GUIC calculations.[21] This amount is approximately $300,000 greater than software costs included in last year's GUIC filing. Given these apparent cost overruns, the Department conducted a detailed analysis regarding the reasonableness of these software costs and issued discovery regarding why costs were greater than initially proposed in last year's filing. The Company provided additional discussion regarding its software costs in its **Trade Secret** response to Department Informal Information Request No. 2 (**Trade Secret** Department Attachment 5).

As part of its response to OAG Information Request No. 9 in the 15-808 Docket, Xcel provided a copy of the contract it signed with a consultant to undertake the Pipeline Data Project (PDP).[22] The PDP involved the digitization of older paper records and the incorporation of these records into the Company's GIS computer software program. This PDP contract is extensive and sets out the cost of the contract, specifics of the work to be completed, and identifies the entities that are parties to the contract.

The Department's analysis of Xcel's actual costs in 2015, relative to what was projected in last year's filing, and their relation to the Company's consulting contract (*see* **Trade Secret** Department Attachment 5), raised serious questions regarding the reasonableness of Xcel's

[21] *Petition*, Page 25.
[22] The Department has included this contract and the Company's contract with Public Service of Colorado, which are trade secret in their entirety, as **Trade Secret** Department Attachment 5.

proposed cost recovery in the current docket. In particular, the Department observed instances where it was unclear if the Company was applying costs in a manner consistent with the contract and regulatory principles. In a general sense, the Department became concerned that Xcel unreasonably shifted costs.

As noted above, the actual costs incurred were significantly higher than the expected costs in last year's filing. The Company did not provide evidence in its *Petition* substantiating these cost overruns. The contract between Xcel and its consultant also explicitly states that **[TRADE SECRET DATA HAS BEEN EXCISED]**; as such, it appears the Company's request to include amounts above the agreed contract amount are unreasonable. The Department raised its concerns with Xcel, and the Department and Xcel discussed this issue in detail during a meeting between the parties on February 17, 2017. The Company noted that only a small portion of the higher costs referenced in this docket relate to the initial consultant contract. Xcel further explained that the majority of the higher costs are associated with an additional consultant review of the PDP, which is separate from the initially executed contract (Department Attachment 6). The Company provided additional data in its **Trade Secret** Response to Informal Information Request No. 2 showing a line-by-line breakdown of the costs associated with the PDP. The additional costs are referred to by the Company as quality assurance/quality control (QA/QC) costs and involve payments to a different consultant who insures that work done in the original contract is appropriate for inclusion in Xcel's GIS system.

Based on its review, the Department concludes that the QA/QC costs of **[TRADE SECRET DATA HAS BEEN EXCISED]** Xcel proposed to include in the GUIC are unreasonable. It is unreasonable to expect ratepayers to bear the costs of duplicative consulting services. The Department does not necessarily oppose the use of reasonable consulting services, but it is not reasonable or acceptable that these services would require an additional level of outside review to ensure that the work is satisfactory. If this additional level of outside review is necessary, it suggests deficiencies in either the Company's contracting oversight process or corporate structures within the Company. In addition, during the February 17, 2017 meeting, Xcel noted that this second layer of review involves individuals who are stationed at Xcel offices and may be engaged in work beyond what was scoped for in the PDP. Since the QA/QC consultations appear to work, at least at some level, with Xcel employees on different types of projects, this agreement is likely a professional services contract. The Department reviewed the Commission's December 6, 2010 *Order* in the Company 2009 rate case (Docket No. G002/GR-09-1153) and notes that at Page 12 the Commission approved a reasonable amount of professional services costs which are included in rate base. Since professional services are already included in rate base, the Department concludes that the QA/QC expenses Xcel included in its GUIC rider are already internalized in rate base. Given these issues, the Department concludes that recovery of these costs through the GUIC are unreasonable.

Second, the Company's decision to assess costs solely to the Minnesota jurisdiction is unreasonable based on the contract and responses to OAG discovery in last year's filing. Based on its review of the contract, the Department observed that the agreement between Xcel and its consultant is **[TRADE SECRET DATA HAS BEEN EXCISED]**. In particular, the contract is between the consultant and **[TRADE SECRET DATA HAS BEEN EXCISED]**. The contract also allows **[TRADE SECRET DATA HAS BEEN EXCISED]**. In its **Trade Secret** response to Informal Information Request No. 2, Xcel responded to the concerns raised by the Department. The Company stated that it had executed a contract with the same vendor used in Minnesota effective July 15, 2014 for the Public Service of Colorado Pipeline Data Project. Xcel further noted that:

> …because other jurisdictions may have similar Pipeline Data Project needs, all operating companies were added to the second contract [*see Department Attachment 4]*, although the scope of the work was only associated with the Minnesota Pipeline Data 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 Pipeline Data 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 [the] 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 Minnesota work was charged to the Minnesota work order and Public Service Company work was charged to the Public Service Company work order.

Based on its review, the Department concludes that Xcel has not met its burden of proof regarding the reasonableness of the $2,073,000 in software costs proposed for recovery through the GUIC rider. Based on the information in this record, the Department cannot verify that work was exclusive to the Minnesota jurisdiction. In fact, Xcel stated in an email response that $49,945 of the original software costs included in previous GUIC filings involved work unrelated to the PDP completed for Public Service Corporation in Colorado (Department Attachment 7). Absent a full forensic audit, which is inappropriate and unreasonable for a rider filing seeking accelerated recovery of rate base, the Department is unable to judge the reasonableness of the Company's proposal. In addition, it is unclear why Xcel would execute a contract **[TRADE SECRET DATA HAS BEEN EXCISED]** when the contract it executed for work in Colorado was exclusive to Public Service Corporation of Colorado (**Trade Secret** Department Attachment 5).

Given the Company's contract language and the $49,945 in non-Minnesota jurisdictional costs previously included in the GUIC, the Department concludes that the most reasonable way to assess costs associated with the PDP is to allocate these costs across all of Xcel's affiliates. Specifically, the Department recommends that the Commission allocate these costs using the FERC Distribution Gas allocator (FERC Accounts 870 and 880) used by Xcel Electric in its 2015 Electric Rate Case (Docket No. E002/GR-15-826). Xcel Electric allocates 29.6370 percent of total Xcel gas distribution costs to NSP-MN, which includes the Minnesota, South Dakota, and North Dakota jurisdiction.

In addition to the allocation of costs between each of Xcel's affiliates, there is also the question of cost allocation between the jurisdictions within NSP-MN. Although the Company classified its PDP as DIMP (direct assignment of costs), Xcel provided no evidence in the record substantiating that the work undertaken by the PDP occurred solely in the Minnesota jurisdiction. As noted above, the scope of the PDP involved the digitization and improvement of access to older gas extension and main data. During the February 17, 2017 meeting, the Company provided examples of the type of work involved with the PDP and, after reviewing the examples, the Department concludes that Xcel has not shown the reasonableness of directly assigning costs to the Minnesota jurisdiction. Similar to the Department's concerns with the PDP contract and the allocation of costs between Xcel affiliates, absent a detailed forensic audit, Xcel cannot prove the reasonableness of directly assigning all costs to the Minnesota jurisdiction. Based on its understanding of the scope of the PDP, the Department has reason to believe that some level of work involved projects or locations that are outside of the Minnesota jurisdiction. As such, the Department recommends that NSP-MN related PDP costs be further allocated in the same manner as Xcel's TIMP costs in this docket, which is an allocation factor of 88.23 percent.[23]

Based on the discussion above, the Department recommends an adjustment to the amount of PDP costs included in the GUIC rider. Specifically, the Department recommends rejection of all QA/QC related costs since they represent duplicative services. The Department also recommends allocation of PDP costs to the Minnesota jurisdiction based on affiliate and jurisdictional allocators because Xcel has not shown that direct assignment of all costs to Minnesota ratepayers is reasonable. The Department concludes that approximately $444,543 in PDP costs are reasonable for recovery from Minnesota ratepayers.

F. RATE OF RETURN ON INVESTMENT

The GUIC Statute allows for a return on investment at the level approved in the utility's last general rate case, unless a different return is in the public interest. Xcel calculated the revenue requirements consistent with its updated 2015 capital structure.

The Department's analysis of the appropriate rate of return for Xcel is contained in Appendix A to these *Comments*. The Department concludes that the Company's proposal to calculate its weighted average cost of capital using the 2015 capital structure and cost of debt from the 2013 electric general rate case to calculate its Rate of Return (ROR) is appropriate. However, based on its analysis, the Department concludes that the Company's proposed Rate of Return on Equity (ROE) of 9.50 percent is unreasonably high and concludes that a ROE of 9.04 is reasonable.

The Department recommends an overall ROR of 7.02 percent, instead of the Company's proposed ROR of 7.26 percent, as summarized in Table 3 below.

[23] *Petition*, Attachment I.

Table 3: Department Recommended Overall Rate of Return for NSP

Component	Component Ratio	Cost	Weighted Cost
	[1]	[2]	[3] = [1] x [2]
Long-term Debt	45.61%	4.94%	2.25%
Short-term Debt	1.89%	1.12%	0.02%
Common Equity	52.50%	9.04%	4.75%
Total	100.00%		7.02%

G. RIDER DURATION

Xcel requested recovery of the following TIMP and DIMP expenditures in 2017:

Table 4[24]
Xcel's Projected 2017 TIMP and DIMP Expenditures
($ Millions)

2017	Capital	O&M
TIMP[25]	$7.86	$1.15
DIMP[26]	$19.52	$4.55
Total	$27.38	$5.70

In its *Petition*, Xcel also provided its 2018-2021 plan for TIMP and DIMP project expenditures. The total TIMP and DIMP projected expenditures from 2018 through 2021 are shown in Table 5 below.

[24] The capital figures shown represent total estimated capital expenditures, including removal costs.
[25] *Petition*, Attachment B, Page 5.
[26] *Petition*, Attachment C, Page 3.

Table 5
Xcel's Projected 2018-2021 TIMP and DIMP Expenditures
($ Millions)

	2018		2019		2020		2021	
	Capital	**O&M**	**Capital**	**O&M**	**Capital**	**O&M**	**Capital**	**O&M**
TIMP[27]	$29.2	$1.1	$33.7	$1.7	$31.8	$1.7	$31.8	$1.7
DIMP[28]	$18.10	$4.25	$18.20	$3.98	$18.20	$0.58	$18.20	$0.58
Total	$47.3	$5.35	$51.9	$5.68	$50.0	$2.28	$50.0	$2.28

In the Company's previous GUIC Rider filing, the Company projected revenue requirements from 2016 through 2020. In the *Petition*, Xcel re-projected the revenue requirements from 2016 through 2021. Table 6 below shows the change in total TIMP and DIMP projected revenue requirements (before the removal of the amount in base rates and the true-up amounts).

Table 6
Change in Total TIMP and DIMP Projected Revenue Requirements
($ Millions)

Docket No.	2016	2017	2018	2019	2020	2021
15-808	$17.9	$23.8	$27.1	$33.4	$32.3	N/A
16-891	$15.8	$22.1	$24.8	$30.6	$28.6	$34.4
Change	$(2.1)	$(1.7)	$(2.3)	$(2.8)	$(3.7)	N/A

The information in Table 6 above shows that the revenue requirements decreased in each year between 2016 and 2020. Based on its review, the Department is not clear what is driving the decrease in the revenue requirements. One possibility is that the Commission's adjustment to the rate of return in last year's filing, and the Company's recommended adjustment to the rate of return in its initial *Petition*, have contributed to the decrease.

Regarding the GUIC Rider duration, the Commission stated in its *Order* in Docket No. 14-336 that it would:

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

The Department reviewed Xcel's Annual Jurisdictional Report for 2015.[29] The weather-normalized return on rate base for 2015 was 7.37 percent, and is projected to be 6.86 percent in 2016. Both of these figures are less than the rate or return authorized in the Company's last gas rate case (8.28 percent), but bracket the Department's current estimate

[27] *Petition*, Attachment B, Page 25.
[28] *Petition*, Attachment C, Page 32.
[29] The Annual Jurisdictional Report for 2016 is due on May 1, 2017.

of the Company's required return of 7.02 percent. At this time, the Department does not recommend that the Commission end the GUIC Rider or recommend that a general rate case be filed, but, as noted in in the issues section above, the Department has identified issues with Xcel's recovery proposals that should be addressed. The Department intends to continue to monitor Xcel's cost recovery proposals and rate of return on rate base proposals in future filings.

H. COMPLIANCE FILING, TRUE-UP REPORT, AND TRACKER BALANCES

Xcel discussed its 2017 GUIC calculations for revenue requirements on Page 23 of its *Petition*.[30] Xcel proposed to increase its 2017 GUIC revenue requirements by approximately $22 million. This figure includes $0.3 million in under-recovery carried over from 2016. The Department notes that Xcel provided actual date for 2016 in its Supplemental Response to Department Information Request No. 5. These updated data show an over-recovery approximately $0.3 million for 2016.

The Department reviewed Xcel's revenue requirements calculations and the updated data from Supplemental Information Request Response No. 5. The Department concludes that the Company's revenue requirements calculations appear reasonable.

Xcel also requested to calculate the final rate adjustment factors to recover the 2017 revenue requirements over the remaining months through March 31, 2018 if the Commission is unable to act on this *Petition* in time for rates to become effective April 1, 2017, and indicated that it would provide those final rate adjustment factors as part of a compliance filing after the Commission's *Order* approving the *Petition*. The Department supports this proposal and notes that at the date these *Comments* are filed, it is unlikely that the Commission will hear this petition before April 1, 2017. Thus, the Department recommends that the Commission approve a tracker year ending March 31 and require Xcel to recover 2017 revenue requirements over the remaining months in 2017 through March 2018.

With the adjustments discussed above, Xcel's revenue requirements calculations appear reasonable and are consistent previous GUIC Rider filings. The Department recommends that the Commission require Xcel to make a compliance filing showing the final rate-adjustment factors reflecting the Commission's decisions in this matter, and all related tariff changes, within ten days of the date of the Commission's *Order*.

I. TARIFF SHEET AND CUSTOMER NOTICE

In Xcel's Attachment R, the Company provided both clean and redline formats of its Tariff Sheet No 5-64. Xcel updated the tariff to reflect its proposed 2017 GUIC factors. If the Commission modifies the proposed revenue requirement or recovery period, then the Department recommends that the Commission require Xcel to make a compliance filing

[30] The GUIC revenue requirement calculations are shown in the *Petition*, Attachments M and N.

showing the final rate-adjustment factors, and all related tariff changes, within ten days of the date of the order.

Xcel noted that it will provide notice to customers regarding the 2017 GUIC Rider in their monthly gas bills.[31] The following is the Company's proposed language to be included as a notice on customers' bills the month that the GUIC factor is implemented:

> This month's Resource Adjustment includes an updated Gas Utility Infrastructure Cost Adjustment (GUIC), which recovers the costs of assessments, modifications and replacement of natural gas facilities as required by state and federal safety programs. The GUIC portion of the Resource Adjustment is $X.XXXX per therm for Residential customers; $X.XXXX per therm for Commercial Firm customers; $X.XXXX for Commercial Demand Billed customers; $X.XXXX per therm for Interruptible customers; and $X.XXXX per therm for Transportation customers. Questions? Contact us at 1-800-895-4999.

Xcel noted in its *Petition* that the Company will work with the Department and Commission Staff if there are any suggestions to modify this notice. The Department concludes that the Company's customer notice uses the same language as the notice approved by the Commission in its August 18, 2016 *Order* in Docket No. 15-808.

J. CONCLUSIONS AND RECOMMENDATIONS

Based on its review, the Department concludes that Xcel's continued recovery of the GUIC Rider is reasonable. However, the Department recommends modifications to Xcel's proposed rates. The Department also recommends that Xcel provide the following in *Reply Comments*:

- Updated schedules reflecting calculation of the GUIC rate based Company's sales forecast before calendar month and DSM adjustments; and
- A detailed analysis comparing the costs of procuring video inspection equipment at the outset of, and each subsequent year until the present, the sewer line inspection plan relative to the expected cost of engaging contractors to complete this work.

The Department also recommends that the Commission:

- Approve Xcel's proposed ADIT proration for the forecasted year in the instant petition, subject to a true-up calculation in the following year using actual non-prorated ADIT amounts;
- Reject all QA/QR related costs included in the GUIC Rider since they represent duplicative services;
- Reject the Company's proposed level of DIMP software costs included in the GUIC;

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

- Adjust DIMP software costs included in rate base for recovery through the GUIC to $444,543;
- Approve a rate of return of 7.02 percent for the GUIC Rider;
- Approve a tracker year ending March 31; and
- Require Xcel to recover 2017 revenue requirements over the remaining months in 2017 through March 2018.

If the Commission modifies the proposed revenue requirement or recovery period, the Department recommends that the Commission require Xcel to make a compliance filing showing the final rate-adjustment factors, and all related tariff changes, within ten days of the date of the *Order*.

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Appendix A to the Comments of the Minnesota Department of Commerce, Division of Energy Resources
Docket No. G002/M-16-891

I. BACKGROUND AND SUMMARY OF XCEL'S PROPOSAL

In its Petition, Xcel proposed to use the same capital structure, cost of long-term debt and cost of short-term debt to develop its proposed authorized rate of return as the Commission approved in the previous GUIC rider, Docket No. G002/M-15-808, with a proposed update only to the Company's cost of common equity. Specifically, rather than the 9.64 percent return on equity (ROE) authorized by the Commission in Xcel's prior GUIC rider, Xcel proposed a cost of equity of 9.50 percent and an authorized rate of return (ROR) of 7.26 percent for its 2017 GUIC filing. Xcel based its proposal on an analysis of the current cost of equity for Xcel's gas operations, performed by an outside consultant, Scott Madden Management Consultants (SMMC, Consultant) as Attachment S to the Petition.

The Department provides its own analysis of Xcel's cost of equity and review of SMMC's analysis.

II. XCEL'S COST OF COMMON EQUITY

A. OVERVIEW OF THE COST OF COMMON EQUITY

To provide reliable service at reasonable rates a utility must be able to compete successfully for necessary funds in the capital markets from investors. Investors are faced with many investment opportunities in the financial markets, so in order to attract investors, the utility must earn enough to be able to pay an equity return similar to the equity return that investors expect to earn on investments of comparable risk. This rate of return is the cost of equity capital to the utility. Thus, a fair return is one that enables the utility to attract sufficient capital, at reasonable terms. A fair rate of return, as required by Minnesota Statutes §216B.16, subd. 6, is the rate that, when multiplied by the rate base, will give the utility a reasonable return on its total investment.

The Department used the following economic guidelines, as set forth in the Bluefield and Hope cases (*Bluefield Water Works & Improvement Company vs. Public Service Commission of the State of West Virginia, et al., 262 U.S. 679 (1923) and Federal Power Commission, et al. vs. Hope Natural Gas Company, 320 U.S. 591 (1944)*):

- The rate of return should be sufficient to enable the regulated company to maintain its credit rating and financial integrity.
- The rate of return should be sufficient to enable the utility to attract capital.

- The rate of return should be commensurate with returns being earned on other investments having equivalent risks.

B. ANALYTICAL MODELS USED

The Department used the Discounted Cash Flow (DCF) model to determine Northern States Power Company's (NSP or NSPM) return on equity. The DCF model postulates that the current price of stock is equal to the present value of all expected future dividends, discounted by the appropriate rate of return. The DCF model is a fair, market-oriented method that uses current, relevant information to determine a rate of return on equity that would allow Xcel to compete sufficiently and fairly in the capital markets.

As a check on the DCF analysis, the Department also used the Capital Asset Pricing Model (CAPM). The CAPM's basic premise is that any company-specific risk can be diversified away by investors. Therefore, the only risk that matters is the systematic risk of the stock, which is measured by beta.

C. SELECTION OF THE DOC PROXY GROUPS

NSP is a subsidiary of Xcel Energy, Inc. and is not publicly traded on a stock exchange. Therefore, DCF analysis cannot be applied directly to NSP. However, it is a well-accepted financial principal that companies with similar investment risks are expected to have similar costs of equity. Therefore, the Department applied DCF analysis to two groups of proxy companies with similar investment risks to NSP.

Because this Petition relates to NSP's gas operations, the Department assembled a group of proxy companies primarily engaged in natural gas distribution. The results of the Department's DCF analysis on this proxy group are indicative of the rate of return on common equity investors require from local distribution companies (LDCs), and are thus indicative of the rate of return a common equity investor in NSP's gas operations would require.

However, NSP has both gas and electric operations, and investors in Xcel Energy, Inc., NSP's parent, are exposed to risks associated with regulated gas operations and regulated electric operations, as well as other non-regulated operations. Therefore, the Department also assembled a proxy group of companies that have both gas and electric operations in order to produce an estimate of the rate of return investors require on investments in utilities that provide both services. This approach is consistent with the Department's approach in NSP's previous GUIC filings and recent rate cases.

1) DOC Gas Proxy Group

The Department developed its proxy group of natural gas distribution companies (the DOC Gas Proxy Group) by compiling an initial list of possible members from two sources. First, the Department ran a query on the Research Insight database for companies that met the following three conditions:

1. have a Standard Industrial Classification (SIC) code of 4924, Natural Gas Distribution, which includes companies "engaged in the distribution of natural gas for sale;"
2. are traded on one of the stock exchanges; and
3. are rated by Standard & Poor's (S&P).

This query produced a list of 9 potential DOC Gas Proxy Group members. To this list, the Department added companies classified by Value Line[1] as Natural Gas Utilities that were not included in the 9 companies from Research Insight. This step added 5 companies to the list of potential members, for a total of 14. From this list of 14 companies, the Department eliminated companies that

1. have S&P credit ratings outside of the range of BBB to A+, or a range of two steps above and two steps below Xcel's rating of A-[2] (this step eliminated three companies)
2. are known to be party to a merger or other significant transaction (didn't eliminate any companies);
3. derive less than 60 percent of their operating income from regulated operations (eliminated three companies), and
4. are not covered by Value Line (which eliminated two companies). [3]

These screens left six companies as members of the DOC Gas Proxy Group.

[1] The Department relies on Value Line for earnings growth estimates (used in its DCF analyses), and beta estimates (used in its CAPM analyses).
[2] Petition, Attachment S, page 10.
[3] DOC Appendix A, Exhibit 1, Schedule 1.

Table 1
DOC Gas Proxy Group

Company	Ticker
Atmos Energy Corporation	ATO
Northwest Natural Gas Company	NWN
South Jersey Industries, Inc.	SJI
Spire Inc	SR
Southwest Gas	SWX
WGL Holdings, Inc.	WGL

2) DOC Combination Proxy Group

The Department developed its proxy group of utilities with a combination of gas and electric operations (the DOC Combination Proxy Group), by compiling an initial list of possible members from two sources. First, the Department ran a query on the Research Insight database for companies that met the following three conditions:

1. have an SIC code of 4931, Electric and other Service Combined, which includes companies “primarily engaged in providing electric services in combination with other services, with electric services as the major part though less than 95 percent of the total;”
2. are traded on one of the stock exchanges; and
3. are rated by Standard & Poor’s (S&P).

This query produced a list of 20 potential DOC Combination Proxy Group members. To this list, the Department added companies classified by Value Line as Electric Utilities that were not included in the 20 companies from Research Insight. This step added 22 companies to the list of potential group members, for a total of 42 potential group members. From this list of 42 companies, the Department eliminated companies that:

1. have S&P credit ratings outside of the range of BBB to A+, or a range of two steps above and two steps below Xcel’s rating of A- (this step eliminated four companies);
2. don’t have long-term annual earnings growth rates provided by Value Line and either Thomson and/or Sacks (this screen eliminated two companies);
3. are known to be, or have recently been, party to a merger or other significant transaction (which eliminated ten companies);
4. have significant operations outside of the US (this step eliminated two companies);
5. aren’t vertically integrated (this step eliminated one company.)
6. derive less than 10 percent of their operating income from regulated gas operations (which eliminated 13 companies), and

7. derive less than 60 percent of their operating income from regulated gas and electric operations, including generation (this step eliminated two companies).[4]

These screens left eight companies as members of the DOC Combination Proxy Group.

Table 2
DOC Combination Proxy Group

Company Name	Ticker
Ameren Corp	AEE
Avista Corp	AVA
CMS Energy Corp	CMS
DTE Energy Co	DTE
Northwestern Corp	NWE
SCANA Corp	SCG
Vectren	VVC
WEC Energy Group Inc	WEC

D. COST OF EQUITY ESTIMATION

As noted above, the Department relied on DCF analyses to develop its estimate of NSPM gas' cost of equity, and used the CAPM as a check on its DCF results.

1) Constant Growth DCF Analyses

The DCF model postulates that the current price of a stock is equal to the present value of all expected future dividends, discounted by the appropriate rate of return, and can be expressed as:

$$P = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \frac{D_3}{(1+k)^3} + \ldots + \frac{D_\infty}{(1+k)^\infty}$$

where P is the current stock price; D_1 is the expected dividend at the end of period one, D_2 is the expected dividend at the end of period two, etc.; and k, the discount rate, is the rate of return that the average investor requires as compensation for the risks associated with owning the stock, known as the cost of equity.

In the special case that dividends are expected to grow at a constant rate over time, known as the "constant growth DCF," the equation above can be rearranged, solved for k and expressed as:

[4] DOC Appendix A, Exhibit 1, Schedule 2.

$$k = \frac{D_1}{P} + g$$

In other words, the cost of equity is equal to the sum of a stock's expected dividend yield and its expected growth rate. While the cost of equity cannot be observed directly, with estimates of a stock's expected dividend yield (in one year) and its dividend growth rate, the cost of equity can be estimated using the above equation.

Estimates of each proxy group member's expected growth rate, g, can be sourced from investment research services. Each company's dividend yield, the first term, can be estimated using its current stock price P, which is directly observable; it's most recent dividend D_0, which is also directly observable; and the company's expected growth rate.

As it does in rate cases, the Department used projected earnings growth rates provided by Zacks' Investment Research (Zacks), a respected investor service; Value Line, another widely used investment service, and Thomson for long-term earnings growth rate estimates.[5] The Department developed three estimates of each proxy group member's cost of equity with the constant growth DCF model: one using the average of the three growth rates; one using the highest of the three growth rates; and one using the lowest of the three growth rates.

The dividend yield in the equation above is equal to the expected dividend at the beginning of the next period (year) divided by the current price (i.e. D_1/P_0). Thus, an estimate of this dividend yield requires an estimate of the expected dividend at the beginning of the next year, and an estimate of the current stock price. To estimate D_1, the Department used each proxy company's current annualized dividend rate, and applied a half-years' worth of growth to reflect the fact that companies pay quarterly dividends and may increase their dividends during any of the next four quarters. To estimate current stock prices, the Department calculated the average closing price of each proxy company's stock over the 30 trading days ending January 25, 2017. Because share prices can be volatile in the short run, it is desirable to use an average share price of a period of time long enough to avoid short-term aberrations in the capital market. However, a share's price at any point of time in the past will necessarily fail to reflect any news or information arising after that point in time that may materially affect the share price. Thus, the period of time should not be too long in order to

[5] The Department uses earnings growth rates, rather than dividend growth rates, because over the long run, growth in dividend per share (as well as growth in book value per share) is derived from the growth in earnings per share. While the short-run growth in dividends may be influenced by management's policy decisions, the long-run sustainable growth in dividends is solely driven from the growth in earnings. Additionally, the use of projected earnings growth rates is well supported by various financial studies and publications. For example, a paper published in "The Journal of Portfolio Management," spring 1998, shows that projected EPS growth rates are the best predictors of stock prices (Investor Growth Expectations: Analysts vs. History: James H. Vandor Weide and Willard T. Carleton)

ensure that the measure of price used to calculate the expected dividend yield appropriately reflects all relevant publicly available information.

The Department also adjusted its constant growth DCF results to reflect flotation costs, which are the costs associated with issuing common stock, by dividing the dividend yield component of the equation above by (1-F), where F is flotation costs measured as a percentage of gross proceeds from common equity issuances. The rate of return on equity approved by the Commission in the 2009 Rate Case included a flotation cost adjustment with F equal to 2.926 percent. The Department used the same estimate of F in the instant Docket.

The results of the Department's constant growth DCF analyses are summarized in Table 3.

Table 3
Summary of Constant Growth DCF Results
Including Flotation Costs

	Low Mean ROE	Mean ROE	High Mean ROE
DOC Gas Proxy Group	7.14%	8.94%	11.08%
DOC Combination Proxy Group	8.85%	9.52%	10.27%
Source: Appendix A, Exhibit 2, Schedules 1 and 7			

2) *Two-Growth Rate DCF Analyses*

In addition to the constant growth DCF model, the Department used a DCF model assuming two growth rates, one rate during the first five years, and a second growth rate in years 6 and beyond. The growth estimates from Zacks, Value Line, and Thomson used in the constant growth DCF analysis are all five-year growth projections, and may not be reasonable to use as proxies for the DCF's long-term, sustainable growth rates. It is possible that investors may have different short-term and long-term expectations regarding a company's financial performance and earnings growth rate, and the two-growth DCF model accounts for situations where the short-term projected growth rates may not be expected to continue in the long run. The short-term earnings growth rate may be unusually low or unusually high, relative to the company's historical averages, industry averages, or relative to the economy as a whole. Unusually low or high growth rates may result in unreasonably low or high estimates of the cost of equity.

The two-growth DCF formula as shown below uses the short-term growth rate for the first five years, and the long-term growth rate in years six and beyond. The two-growth rate DCF formula is:

$$P = \frac{D_1}{(1+k)} + \frac{D_1(1+g_1)}{(1+k)^2} + \frac{D_1(1+g_1)^2}{(1+k)^3} + \frac{D_1(1+g_1)^3}{(1+k)^4} + \frac{D_1(1+g_1)^4}{(1+k)^5} +$$

$$\frac{D_1(1+g_1)^4(1+g_2)}{(k-g_2)} \times \frac{1}{(1+k)^5}$$

The first five terms in the equation above are the dividends in years one through five, growing at the first growth rate, g_1, discounted back to the present using the required rate of return or cost of equity k. The sixth term in the equation is the stock price in year five, estimated as the dividend in year six divided by k minus the second growth rate, discounted back to the current year.

The growth rates the Department used in the constant growth DCF analysis, from Zacks, Value Line, and Thomson, are five-year projected earnings growth rates. Because the short-term period in my two-growth DCF analysis represents the first five years of the analysis, the Department used those projections as the short-term growth rates in its two-growth DCF.

For the second growth rate, used in years six and beyond, the Department calculated the average short-term growth rate for each of its two proxy groups, as well as the standard deviation of each group's growth rates. The Department assumed that that any growth rate that is lower than one standard deviation below its proxy group's average may not be sustainable and that any growth rate higher than one standard deviation above the proxy group's average growth rate may not be sustainable. Thus, the Department used each proxy group's average short-term growth rate plus and minus one standard deviation as the ceiling and floor, respectively, for sustainable growth rates. For growth rates less than one standard deviation below the proxy group's average, the Department substituted the proxy group's average less one standard deviation. Similarly, for growth rates more than one standard deviation above the proxy group's average, the Department substituted the proxy group's short-term average growth rate plus one standard deviation.

The Department applied the same adjustment for flotation costs to its two-growth DCF results as it applied to its constant-growth DCF analysis.

The results of the Department's two-growth DCF results are summarized in Table 4.

Table 4
Summary of Two Growth Rate DCF Results
Including Flotation Costs

	Low Mean ROE	Mean ROE	High Mean ROE
DOC Gas Proxy Group	6.97%	8.93%	10.96%
DOC Combination Proxy Group	8.90%	9.47%	10.14%
Source: DOC Appendix A, Exhibit 2, Schedules 2-4 and 8-10			

3) The Capital Asset Pricing Model

The basic premise of CAPM is that any company-specific risk can be diversified away by investors. Therefore, the only risk that matters is the systematic risk of the stock, which is measured by beta. In its simplest form, CAPM assumes the following:

$$k = r_f + \text{beta (market risk premium)}$$

Where k is the required rate of return on the stock in question, r_f is the rate of return on a riskless asset, and k_m is the required rate of return on the market portfolio.

While the CAPM is theoretically sound, its use raises some difficult issues. These issues include determining the appropriate beta, the appropriate "riskless" asset, and an appropriate estimate of the required return on the market portfolio. Because of these issues, the Department does not rely on the CAPM directly to determine a utility's cost of equity, but uses it only indirectly to assess the reasonableness of the Department's DCF analyses. Additionally, the Commission has, in past Dockets, expressed a clear preference for DCF analyses. For example, in its May 8, 2015 Order in the 2013 Rate Case, the Commission stated that the DCF is the method "on which this Commission has historically placed its heaviest reliance."

For the rate of return on a risk free asset, the Department used the current 30-day average yield on 20-year US Treasury bonds. While all US Treasuries are thought to be devoid of default risk, longer-term treasuries expose investors to interest rate risk, which, in a general sense, is the risk associated with investment opportunities foregone because cash is tied up in investments made earlier. For example, if a person buys a 30-year Treasury bond carrying a six percent interest rate today, and a year hence a new 30-year Treasury bond with a rate of seven percent is issued, then holding the original bond to maturity would cost this person the opportunity to earn seven percent interest, rather than six percent for the next 29 years.

Similarly, shorter term treasuries such as the 90-day Treasury bill expose investors to face reinvestment risk, which is the risk that proceeds from the payment of principal and interest would have to be reinvested at a lower rate than the original investment, if the investor were to invest in 90-day Treasury bills. Equity investors generally have an investment horizon far in excess of 90 days and thus, an equity investor wanting to invest in an asset yielding the risk-free rate for a period comparable to the investor's stock holding period would face reinvestment risk, which is the risk that proceeds from the payment of principal and interest would have to be reinvested at a lower rate than the original investment, if the investor were to invest in 90-day Treasury bills. The 20-year Treasury bond reasonably balances these risks.

For an estimate of the market rate of return, k_m, the Department performed a constant growth DCF analysis on the S&P 500 index to determine the return investors in the S&P 500 currently require. As noted above, the constant growth DCF can be simplified such that the required return on equity equals the sum of an investment's dividend yield and its expected growth rate:

$$k = \frac{D_1}{P} + g$$

In a slight change from past practice, the Department used an Electronically Traded Fund (ETF) as a proxy index fund for the S&P 500 portfolio. (See www.spdrs.com/product.fund.seam?ticker=SPY.)

According to the information on this website, as of February 7, 2017:

- the dividend yield for the S&P 500 was 1.98 percent;[6]
- the Department applied a half years' worth of growth to this dividend yield, resulting in a dividend yield of 2.09 percent, and
- the three to five-year projected earnings per share growth rate for the S&P 500 Index was 11.22 percent.

Thus, the required rate of return on the S&P 500 is:

2.09 percent + 11.22 percent = 13.31 percent

As noted above, the Department sourced estimates of beta for each of the companies in the DOC Proxy Groups from Value Line, and used the average beta of each Group as an estimate of beta for Xcel. The average beta for the DOC Gas Proxy Group was 0.73.

[6] All of the data and calculations in the Department's CAPM analyses are contained in Appendix A, Exhibit 2.

Thus, the Department's estimate for NSP-MN Gas's required rate of return based on its CAPM analysis is:

$k = r_f + \beta (r_m - r_f)$
k = 2.79 percent + 0.73 (13.31 percent – 2.09 percent)
k = 10.42 percent.

The average beta for the DOC Combination Proxy Group was 0.71. Thus, the Department's estimate for the NSP-MN's required rate of return based on the Combo Proxy Group CAPM analysis is:

$k = r_f + \beta (r_m - r_f)$
k = 2.79 percent + 0.71 (13.31 percent – 2.09 percent)
k = 10.24 percent.

After adjusting for flotation costs, the CAPM estimates for the DOC Gas and DOC Combination Proxy Groups are 10.51 and 10.33 percent respectively. Both estimates fall within the ROE range provided by the weighting of the Department's two-growth DCF models for DOC Gas and DOC Combination Proxy Groups developed below.

4) Recommended Return on Equity for NSP

In the 2009 Rate Case, the Commission approved a rate of return on equity based on a weighted average of the ROE results for combination electric and gas utilities, and the results for LDC utilities, with weights of 21 percent and 79 percent, respectively. Because one of the purposes of this proceeding is to determine a reasonable rate of return for NSP's gas operations, it is appropriate to weight the ROE for the DOC Gas Proxy Group more heavily than the ROE for the DOC Combination Proxy Group. Thus, the Department used these weights for its two proxy groups.
Based on its mean two growth rate DCF analyses, the Department concludes that a reasonable rate of return on equity for NSP's gas operations is 8.93 percent, and a reasonable rate of return for NSP overall, reflecting its gas and electric operations, is 9.47 percent. Applying the same weights to the Department's ROE estimates yields a rate of return on common equity of 9.04 percent (8.93 x .79 + 9.47 x .21 = 9.04). The results of the weighting of the Department's two-growth DCF results including the high and low estimates are summarized in Table 5.

Table 5
Weighted ROE Range

	Low Mean ROE	Mean ROE	High Mean ROE
DOC Gas Proxy Group	6.97%	8.93%	10.96%
Gas Weighting	79.00%	79.00%	79.00%
DOC Gas Proxy Grp Weighted ROE	5.51%	7.05%	8.66%
DOC Combination Proxy Group	8.90%	9.47%	10.14%
Combination Weighting	21.00%	21.00%	21.00%
DOC Combination Proxy Grp Weighted ROE	1.87%	1.99%	2.13%
Weighted ROE Range	7.38%	9.04%	10.79%

III. THE CAPITAL STRUCTURE, COST OF DEBT, AND OVERALL COST OF CAPITAL

In its Petition, the Company proposed to use the approved 2015 capital structure and costs of short- and long-term debt to calculate its weighted average cost of capital. This proposal is consistent with the capital structure that the Commission approved in the Company's 2016 GUIC rider petition (Docket No. G002/M-15-808).

Similar to its analysis in prior years, the Department reviewed NSP-MN's capital structure from its past three general rate proceedings. Table 6 summarizes the capital structures and costs of short- and long-term debt from the 2009, 2013, and 2015 Rate Cases.

Table 6
Summary of Capital Structures Proposed Capital Structures

	2009 Rate Case		2013 Rate Case		2015 Rate Case*	
	2010 Test Year		2015 Test Year		2016 Test Year	
	Component Ratio	Cost	Component Ratio	Cost	Component Ratio	Cost
Long-Term Debt	46.74%	6.36%	45.61%	4.94%	46.24%	4.81%
Short-Term Debt	0.80%	1.36%	1.89%	1.12%	1.26%	1.84%
Common Equity	52.46%	n/a	52.50%	n/a	52.50%	n/a
Total	100.00%		100.00%		100.00%	

Sources and Notes:
2009 Rate Case: WACC Compliance Filing, page 5
2013 Rate Case: WACC Compliance Filing, page 5
2015 Rate Case: Docket No. E002/GR-15-826, Direct Testimony of Brian J. Van Abel, page 4
* Proposed

Due to the stability of Xcel's test year capital structures over time, the Department concludes that Xcel's proposal to use the 2015 capital structure and costs of short- and long-term debt approved in the 2013 Rate Case to calculate WACC in the instant Docket is reasonable.

Using the 2015 capital structure and cost of debt from the 2013 Rate Case in combination with a cost of equity of 9.04 percent yields an overall cost of capital of 7.02 percent, which the Department recommends as the ROR for NSP's GUIC Rider. Table 7 summarizes this information.

Table 7
Department Recommended
Overall Rate of Return for NSP

Component	Component Ratio	Cost	Weighted Cost
	[1]	[2]	[3] = [1] x [2]
Long-term Debt	45.61%	4.94%	2.25%
Short-term Debt	1.89%	1.12%	0.02%
Common Equity	52.50%	9.04%	4.75%
Total	100.00%		7.02%

IV. CRITIQUE OF THE COMPANY'S ANALYSIS

In the Company's Petition, SMMC used two forms of DCF analysis, the CAPM, and a bond yield plus risk premium method to estimate Xcel's cost of equity. Similar to the Department, for its DCF and CAPM analyses, SMMC developed two proxy groups, one composed of LDCs and one composed of combination electric and gas utilities. SMMC applied the bond yield plus risk method only to natural gas utilities. Based on its analyses, as noted above, Xcel concluded that a return on equity of 9.50 percent is reasonable.

The Department disagrees with several aspects of SMMC's DCF, CAPM and bond yield plus risk premium analyses, described below. Additionally, the Department disagrees with the way the Company averaged the results of its various analyses to derive a single estimate of NSP's cost of equity. In doing so, SMMC weighted its CAPM and bond yield plus risk premium results equally with its DCF results, despite the Commission's clear preference for DCF analysis.

A. XCEL'S PROXY GROUPS

SMMC described the screening processes used to develop its two proxy groups on pages 9-12 of Attachment S of the Petition.

SMMC's LDC Proxy Group contains eight gas utility companies, including all six members of the DOC Gas Proxy Group, plus two additional companies: Chesapeake Utilities Corporation, and New Jersey Resources Corporation. SMMC included Chesapeake Utilities in its Gas Proxy Group even though its debt is not publicly rated by S&P. Given that this is one of the screening criteria that both SMMC and the Department use to develop its respective proxy group, the Department concludes that SMMC's inclusion of Chesapeake in the Company's Gas Proxy Group is inconsistent with that screen. The Department excluded Chesapeake from the Department Gas Proxy Group on that basis.

Regarding New Jersey Resources, NJR filed its SEC Form 10-K for the 12 months ending September 30, 2015, and during that fiscal year, the New Jersey Resource's operating income attributable to gas distribution operations was below 60 percent of its total. As a result, the Department excluded NJR from its proxy group. However, the Department notes that SMMC used a three-year average of NJR's operating income as the basis for its screen. Thus SMMC still includes New Jersey Resources in its Gas Proxy Group, despite the fact that the most recent results signal that NJR should be excluded.

SMMC's Combination Proxy Group contains ten combination electric and gas utilities, including all eight of the companies in the DOC Combination Proxy Group. The other two members of the Company's Combination Proxy Group are CenterPoint Energy, Inc. and NiSource, Inc.

The Department excluded CenterPoint Energy, Inc. because it has electric operations only in deregulated markets (Texas and New York) and provides electric transmission and distribution services only. CenterPoint does not own any generation assets.

The Department did not include NiSource as a potential member of its combination proxy group. NiSource has a SIC code of 4932[7] and is categorized by Value Line as a natural gas utility. The Department used only companies with SIC codes of 4931 and companies classified by Value Line as electric utilities as potential proxy group members in order to include only companies primarily engaged in electric operations, as is NSP.

B. SMMC'S DCF ANALYSES

1) Constant Growth DCF

SMMC used two forms of DCF analyses on each proxy group; the constant growth DCF and a two-stage DCF analysis. In its constant growth DCF analysis, SMMC used three estimates of dividend yields, calculated with average closing stock prices over 30-, 90- and 180—trading day periods ending September 30, 2016. Like the Department, SMMC also applied a half years' worth of growth to each dividend yield. For growth rates, SMMC used estimates from the same three investors services as the Department (Zacks, Value Line and Thomson), and calculated ROE estimates using the lowest of the three, the average of the three, and the highest of the three. Thus, for each company in its proxy group, SMMC developed nine cost of equity estimates (three dividend yield estimates times three growth rates).

[7] SIC Code 4932 is assigned to establishments primarily engaged in providing gas services in combination with other services, with gas services as the major part though less than 95 percent of the total.

The Department disagrees with SMMC's use of 90- and 180-day trading periods to calculate dividend yields, as stock prices from that long ago may reflect out-of-date information, as described above. Only the estimates produced with the 30-day trading period are reasonable. Thus, while the Department has no significant disagreements with SMMC's constant growth DCF analysis, the Department disagrees with SMMC's use of out-of-date market information and with the impact of the differences in our proxy groups.

The Department notes that removing Chesapeake Utilities and New Jersey Resources Corporation from the SMMC's Gas Proxy Group while holding all other factors unchanged causes SMMC's 30-day constant growth DCF ROE estimate to rise from 8.66 percent to 8.97 percent.[8] The difference between this estimate of 8.97 percent and the Department's result of 8.85 percent (without flotation costs) is due to changes in market conditions (i.e. stock prices, dividends, and expected growth rates) between the time of SMMC's analysis and the Department's analysis.

Removing CenterPoint and NiSource from SMMC's Combination Proxy Group causes its 30-day constant growth DCF ROE to rise from 8.96 percent to 9.19 percent, which is still well below the Department's result of 9.41 percent before accounting for flotation costs.[9] As noted previously, the difference between SMMC's estimate using the Department's Combination Proxy Group of 9.19 percent and the Department's own estimate using its Combination Proxy Group of 9.41 percent is due to changes in market conditions between the time of SMMC's analysis and the Department's analysis.

2) Two-Stage DCF

In addition to its constant growth DCF analysis, SMMC used a two-stage DCF analysis, as described in Attachment A, pages 15-18 of Attachment S of the Petition. SMMC's two-stage DCF is similar to the Department's two-stage DCF model described earlier in this document.

Similar to its constant growth DCF, SMMC calculated the average stock price of each member of the proxy groups using 30-, 90- and 180-trading day closing stock price averages, and estimated each proxy group member's cost of equity assuming low, average, and high growth rates with each dividend yield, for a total of nine multi-stage DCF estimates per proxy group member.

Again, the Department takes issue with the SMMC's use of 90- and 180-day trading periods to calculate dividend yields since those prices reflect information that is likely no longer relevant. Other than this difference, and the impact of the differences in our proxy groups, the Department has no significant disagreements with SMMC's two-growth DCF analysis.

[8] DOC Appendix A, Exhibit 4, Schedule 1.
[9] DOC Appendix A, Exhibit 4, Schedule 7.

Similar to the Department's analysis of SMMC's constant growth DCF analysis in which the Department modified SMMC's LDC Proxy Group so that it was consistent with the Department's Gas Proxy Group, the Department removed Chesapeake Utilities and New Jersey Resources Corporation from SMMC's Gas Proxy Group, while holding all other factors unchanged. This modification causes SMMC's 30-day mean two-growth DCF ROE estimate to rise from 8.65 percent to 8.98 percent.[10] The difference between this estimate of 8.98 percent and the Department's result of 8.84 percent (without flotation costs) is due to changes in market conditions (i.e. stock prices, dividends, and expected growth rates) between the time of SMMC's analysis and the Department's analysis.

Performing the same exercise for SMMC's Combination Proxy Group assuming a 30-day average two-growth DCF scenario increases the resulting mean ROE from 8.99 to 9.18 percent (before flotation costs).[11] It appears that the difference between the 9.18 percent estimate derived using modified NSP Combination Proxy Group in the SMMC two-growth model and the 9.36 percent estimate developed using the Department's two-growth model is due to timing differences in market conditions.

C. SMMC'S CAPM ANALYSIS

As noted above, application of the CAPM requires estimates of three parameters: the risk-free rate, beta, and the required return on the market portfolio. As described on pages 18-20 of Attachment S to the Petition, SMMC developed two estimates of the risk-free rate, two estimates of the required return on the market portfolio, and four estimates of beta (two for the LDC proxy group, and two for the Combination Proxy Group), and ultimately developed 16 estimates of Xcel's required ROE using the CAPM.

SMMC's estimates of the risk-free rate are the current 30-day average yields on 30-year Treasury bonds of 2.32 percent and a projected 2.80 percent yield on 30-year Treasury bonds.

SMMC derived two estimates of the required market return on the S&P 500, using data from Bloomberg and Value Line. Using these data, SMMC performed a constant growth DCF analysis for each of the 500 companies in the S&P 500 and calculated the average DCF result for the entire group weighted by market capitalization.

The Consultant's estimates of beta are the average of the betas for the members of the two proxy groups. SMMC sourced estimates of beta from two sources: Bloomberg and Value Line.

[10] DOC Appendix A, Exhibit 4, Schedule 3.
[11] DOC Appendix A, Exhibit 4, Schedule 9.

As shown on page 21 of Attachment S, the Consultant's CAPM results range from 9.04 percent to 11.28 percent for the LDC Proxy Group and from 9.03 percent to 11.12 percent for the Combination Proxy Group.

While the Department does not agree with SMMC's choice of risk-free rate, as described above, the Department notes that recalculating the Consultant's CAPM results using yields on 20-year Treasuries rather than 30-year Treasuries would have only a small impact on SMMC's CAPM results. The Department's larger disagreement, described below, is that the Consultant gave its DCF results and its CAPM results equal weighting in developing its final recommendation, despite the Commission's stated preference for DCF analysis.

D. BOND YIELD PLUS RISK PREMIUM ANALYSIS

SMMC's bond yield plus risk premium analysis is described on pages 22 and 23 of Attachment S. This approach treats the cost of equity as a sum of an equity risk premium and a bond yield. The Consultant gathered data on the authorized returns on equity from 1,045 natural gas rate cases since 1980, as well as the concurrent yields on 30-year Treasuries, which SMMC chose as the representative bond yield. The Consultant defined the risk premium as the difference between the authorized return and the concurrent yield on 30-year Treasuries, and estimated the market risk premium associated with each authorized return on equity. Then, SMMC used regression analysis to estimate the risk premium as a function of the natural log of the prevailing 30-year Treasury yields using the following equation:

$$\text{Risk Premium} = \alpha + \beta * \ln(\text{Treasury yield})$$

SMMC estimated the constant, α, to be negative 0.0291 and the coefficient, β, to be negative 0.0282. Using this equation and the current yield on 30-year Treasuries and two projected yields, the Consultant estimated the cost of equity for natural gas utilities to be between 9.95 and 10.30 percent.

SMMC's analysis, however, inappropriately assumes that both coefficients, $\alpha = -0.0291$ and $\beta = -0.0282$ are stable over time and do not depend on investors adjusting their expectations depending on different Federal monetary and fiscal policies. To the degree that investors adjust their behavior to adapt to changing Federal policies, neither of the coefficients are stable and therefore cannot be used to estimate the expected risk premium.

E. RECENTLY AUTHORIZED GAS UTILITY RETURNS ON EQUITY

On pages 24 and 25 of Attachment S, SMMC provided a summary of authorized ROEs in gas utility rate cases decided since January 2015. The Consultant used this information to calculate an average approved ROE for this time period.

SMMC's analysis is historical and based on different facts, so it is of little value to the Commission in terms of setting NSP's ROE in this proceeding. The Department recommends that the Commission use the DCF model results as the basis for its decision as the DCF model provides a forward-looking estimate of NSP's ROE. This is a much more relevant perspective than SMMC's historical perspective.

F. Current and Expected Capital Market Conditions

SMMC discussed the possibility of increases to the Federal Funds rate by the Federal Reserve in 2017 and beyond on pages 26 through 28 of Attachment S. The Consultant's position is "that investors believe that it is considerably more likely that interest rates will increase over the coming year, than it is that they will decrease".[12] Given that increasing interest rates increase yields and result in lower prices for existing bonds, the Consultant appears to imply that such a development would put downward pressure on gas and electric utility share prices and could potentially lead to higher ROE's in the future.

In response, the Department notes that investor expectations regarding future interest rates or changes to other general economic factors are already fully reflected in asset prices (and by extension the proxy group's share prices.) Thus, to the extent that the assertion above is accurate, utility share prices already reflect that expectation and is thus fully incorporated into the Department's DCF models (which assume that a utility's share price is based on the present value of its future dividend stream).

G. SCOTT MADDEN MANAGEMENT CONSULTANT'S OVERALL CONCLUSIONS

To develop a single ROE estimate for NSP from the multiple approaches it took to estimate NSP's cost of equity, SMMC selectively averaged the results of each ROE approach separately (i.e. constant growth DCF, multi-stage DCF, CAPM, and bond yield plus risk premium), then averaged these averages by proxy group. Finally, SMMC calculated a weighted average of the results from each of its two proxy groups, using the same weights applied in the 2009 Rate Case. As a result, the Consultant calculated an overall weighted average ROE of 9.57 percent.[13] Subsequently, SMMC then recommended an ROE of 9.50 percent.

The Department's primary concern is that SMMC's calculation of its overall weighted average ROE treats the CAPM and bond yield plus risk premium approaches as equal to the two DCF approaches. As noted above, the Commission has relied more heavily on the DCF approach than other approaches. Further, as described above, while CAPM is theoretically sound, application of the CAPM in practice is problematic due to:

- difficulty estimating beta and a "riskless" rate needed for the CAPM model;

[12] See Petition, Attachment S at page 28.
[13] See Petition, Attachment S, page 29.

- the theoretical soundness of the bond yield plus risk premium approach, and
- the value of historical authorized ROEs given that ROE is a forward looking concept.

Thus the Department's concludes that SMMC's averaging approach should be given little to no weight in the Commission's review.

V. CONCLUSION

The Department concludes that Xcel's proposal to use the 2015 capital structure and cost of debt from the 2013 Rate Case to calculate its ROR in this proceeding is appropriate.

However, the Department concludes that the Company's recommended ROE of 9.50 percent, is not reasonable for Xcel's gas operations. SMMC's overall analysis supporting this ROE weights the results of its CAPM and bond yield plus risk premium too heavily.

Instead, the Department recommends a rate of return on equity of 9.04 percent for the Company, and an overall rate of return of 7.02 percent.

DOC Proxy Group Screening Process
DOC Local Distribution Company Proxy Group - Standard Industrial Classification Code 4924 Component

Line No.	Company	Ticker	SIC Code	Stock Exchange	S&P Debt Rating	S&P Debt Ratings Between BBB and A+	Absence of Merger or Acquisition Activity	60% Operating Income from U.S. Regulated Retail Ops.	Covered by Value Line	DOC Proxy Group Member	Notes
	Companies from Research Insight Query										
1.	Atmos Energy Corp	ATO	4924	NYSE	A	y	y	y	y	y	
2.	Enbridge	ENB	4924	NYSE	BBB+	y	y	**n**			[1] [2]
3.	Energen	EGN	4924	NYSE	BB	**n**					
4.	National Fuel Gas Company	NFG	4924	NYSE	BBB	y	y	**n**			
5.	Northwest Natural Gas Company	NWN	4924	NYSE	A+	y	y	y	y	y	
6.	ONE Gas, Inc.	OGS	4924	NYSE	A-	y	y	y	**n**		
7.	South Jersey Industries, Inc.	SJI	4924	NYSE	BBB+	y	y	y	y	y	
8.	Spire Inc	SR	4924	NYSE	A-	y	y	y	y	y	
9.	WGL Holdings, Inc.	WGL	4924	NYSE	A+	y	y	y	y	y	
	Additional Companies from Value Line										
10.	Chesapeake Utilities	CPK	4923	NYSE	not rated	**n**					
11.	New Jersey Resources Corporation	NJR	4924	NYSE	A	y	y	y	**n**		[3]
12.	Southwest Gas	SWX	4923	NYSE	BBB+	y	y	y	y	y	
13.	UGI Corporation	UGI	4932	NYSE	not rated	**n**					
14.	NiSource, Inc.	NI	4932	NYSE	BBB+	y	y	**n**			
	Number of Companies in DOC Local Distribution Company Proxy Group									6	

Notes:

1) Bold text signifies the screen that eliminated the company.
2) Blank cells indicate that the screen was not performed as the company had failed a prior screen.
3) Credit rating reported for New Jersey Resources Corporation (NJR) is S&P credit rating for New Jersey Natural Gas, NJR's natural gas distribution subsidiary.

DOC Proxy Group Screening Process
Revised DOC Proxy Group - Standard Industrial Classification Code 4931 Component

Line No.	Company	Ticker	SIC Code	S&P Debt Rating	S&P Debt Ratings Between BBB and A+	Covered by Value Line	Absence of Merger or Acquisition Activity	No Significant International Operations	10% Operating Income from U.S. Regulated Gas Ops.	60% Operating Income from U.S. Regulated Gas and Electric Ops.	DOC Proxy Group Member	Notes
1.	ALLETE INC	ALE	4931	BBB+	y	y	y	y	n			[1] [2]
2.	Alliant Energy Corp	LNT	4931	A-	y	y	y	y	n			
3.	Ameren Corp	AEE	4931	BBB+	y	y	y	y	y	y	y	
4.	Avista Corp	AVA	4931	BBB	y	y	y	y	y	y	y	
5.	Centerpoint Energy Inc.	CNP	4931	A-	y	y	y	y	y	y	n	[3]
6.	CMS Energy Corp	CMS	4931	BBB+	y	y	y	y	y	y	y	
7.	Consolidated Edison Inc	ED	4931	A-	y	y	y	y	y	n		
8.	DTE Energy Co	DTE	4931	BBB+	y	y	y	y	y	y	y	
9.	Duke Energy Corp	DUK	4931	A-	y	y	n					
10.	Eversource Energy	ES	4931	A	y	y	y	y	n			
11.	Genie Energy Ltd	GNE	4931	not rated	n							
12.	MGE Energy Inc	MGEE	4931	not rated	n							
13.	Northwestern Corp	NWE	4931	BBB	y	y	y	y	y	y	y	
14.	OGE Energy Corp	OGE	4931	A-	y		y	y	n			
15.	PG&E Corp	PCG	4931	BBB+	y	y	n					
16.	Public Service Entrp Grp Inc	PEG	4931	BBB+	y	y	y	y	y	n		
17.	SCANA Corp	SCG	4931	BBB+	y	y	y	y	y	y	y	
18.	Sempra Energy	SRE	4931	BBB+	y	y	y	n				
19.	Unitil Corp	UTL	4931	BBB+	y	n						
20.	WEC Energy Group Inc	WEC	4931	A-	y	y	y	y	y	y	y	
	Additional Companies from Value Line											
21.	American Electric Power	AEP	4911	BBB+	y	y	y	y	n			
22.	Avangrid Inc	AGR	4911	BBB+	y	y						[4]
23.	Black Hills Corp	BKH	4911	BBB	y	y	n					
24.	Dominion Resources	D	4911	BBB+	y	y	n					
25.	Edison International	EIX	4911	BBB+	y	y	y	y	n			
26.	El Paso Electric	EE	4911	BBB	y	y	y	y	n			
27.	Empire District Electric Co	EDE	4911	BBB	y	y	n					

DOC Proxy Group Screening Process
Revised DOC Proxy Group - Standard Industrial Classification Code 4931 Component

Line No.	Company	Ticker	SIC Code	S&P Debt Rating	S&P Debt Ratings Between BBB and A+	Covered by Value Line	Absence of Merger or Acquisition Activity	No Significant International Operations	10% Operating Income from U.S. Regulated Gas Ops.	60% Operating Income from U.S. Regulated Gas and Electric Ops.	DOC Proxy Group Member	Notes
28.	Entergy	ETR	4911	BBB+	y	y	y	y	**n**			
29.	Exelon	EXC	4911	BBB	y	y	**n**					
30.	First Energy	FE	4911	BBB-	**n**							
31.	Fortis Inc.	FTS	4911	A-	y	y	**n**					
32.	Great Plains Energy, Inc	GXP	4911	BBB+	y	y	**n**					
33.	Hawaiian Electric	HE	4911	BBB-	**n**							
34.	IdaCorp, Inc.	IDA	4911	BBB	y	y	y	y	**n**			
35.	NextEra Energy	NEE	4911	A-	y	y	**n**					
36.	Otter Tail Corporation	OTTR	4911	BBB	y	y	y	y	**n**			
37.	PNM Resources	PNM	4911	BBB+	y	y	y	y	**n**			
38.	Pinnacle West Capital Corp	PNW	4911	A-	y	y	y	y	**n**			
39.	Portland General	POR	4911	BBB	y	y	y	y	**n**			
40.	PPL Corp	PPL	4911	A-	y	y	y	**n**				
41.	Southern Company	SO	4911	A-	y	y	**n**					
42.	Vectren	VVC	4923	A-	y	y	y	y	y	y	y	
	Number of Companies in DOC Combination Proxy Group										8	

Notes:

1) Bold text signifies the screen that eliminated the company.
2) Blank cells indicate that the screen was not performed as the company had failed a prior test.
3) Centerpoint was excluded from the DOC Combination Proxy Group for reasons discussed in the Department's comments.
4) While Value Line has initiated coverage of Avangrid, the information developed is not sufficient for the DOC to include Avangrid in its comparable group.

Constant Growth DCF Analysis - DOC Natural Gas Proxy Group

Company	Ticker	Average Closing Price	Annualized Dividend	Dividend Yield	Low Projected Growth Rate	Mean Projected Growth Rate	High Projected Growth Rate	Low Expected Dividend Yield	Mean Expected Dividend Yield	High Expected Dividend Yield	Low ROE	Mean ROE	High ROE
		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Atmos Energy Corp	ATO	74.28	1.80	2.42%	6.50%	6.93%	7.30%	2.50%	2.51%	2.51%	9.00%	9.44%	9.81%
Northwest Natural Gas	NWN	59.68	1.88	3.15%	4.00%	5.13%	7.00%	3.21%	3.23%	3.26%	7.21%	8.36%	10.26%
South Jersey Industries	SJI	33.27	1.09	3.28%	3.00%	6.33%	10.00%	3.33%	3.38%	3.44%	6.33%	9.71%	13.44%
Southwest Gas Corp	SWX	77.00	1.80	2.34%	4.00%	5.15%	7.00%	2.38%	2.40%	2.42%	6.38%	7.55%	9.42%
Spire Inc	SR	64.50	2.10	3.26%	4.04%	5.82%	9.00%	3.32%	3.35%	3.40%	7.36%	9.17%	12.40%
WGL Holdings	WGL	77.66	1.95	2.51%	3.50%	6.28%	8.00%	2.55%	2.59%	2.61%	6.05%	8.87%	10.61%
Mean				2.83%	4.17%	5.94%	8.05%	2.88%	2.91%	2.94%	7.06%	8.85%	10.99%
Required ROE including flotation cost adjustment											7.14%	8.94%	11.08%
Flotation Costs											2.93%		

Sources and Notes:
[1] Appendix A, Exhibit 2, Schedule 6
[2] Appendix A, Exhibit 2, Schedule 5
[3] = [2] / [1]
[4] Appendix A, Exhibit 2, Schedule 5
[5] Appendix A, Exhibit 2, Schedule 5
[6] Appendix A, Exhibit 2, Schedule 5
[7] = [3] x (1 + 0.5 x [4])
[8] = [3] x (1 + 0.5 x [5])
[9] = [3] x (1 + 0.5 x [6])
[10] = [4] + [7]
[11] = [5] + [8]
[12] = [6] + [9]

Two Growth Rate DCF Analysis - DOC Final Natural Gas Proxy Group
Low Growth Rates

Ticker	Average Closing Price	Annualized Dividend	Dividend Yield	Low Projected Growth Rate	Low Expected Dividend Yield	Second Growth Rate		Low Expected ROE
	[1]	[2]	[3]	[4]	[5]	[6]		[7]
ATO	74.28	1.80	2.42%	6.50%	2.50%	5.28%		7.92%
NWN	59.68	1.88	3.15%	4.00%	3.21%	4.00%		7.21%
SJI	33.27	1.09	3.28%	3.00%	3.33%	3.07%		6.38%
SWX	77.00	1.80	2.34%	4.00%	2.38%	4.00%		6.38%
SR	64.50	2.10	3.26%	4.04%	3.32%	4.04%		7.36%
WGL	77.66	1.95	2.51%	3.50%	2.55%	3.50%		6.05%
Mean			2.83%	4.17%	2.88%	3.98%		6.89%
With Flotation Costs								6.97%
		Average		4.17%				
		Std. Dev.		1.10%			Flotation Costs (F)	2.93%
		Avg. less St. Dev.		3.07%				
		Avg. plus St. Dev		5.28%				

Ticker	Year 1 Div.	(1+k)^1	PV of Year 1 Div.	Year 2 Div.	(1+k)^2	PV of Year 2 Div.	Year 3 Div.	(1+k)^3	PV of Year 3 Div.	Year 4 Div.	(1+k)^4	PV of Year 4 Div.	Year 5 Div.	(1+k)^5	PV of Year 5 Div.	Year 6 Div.	Year 5 Stock Price	PV of Year 5 Stock Price	Current Stock Price	CHECK
	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]
ATO	1.86	1.08	1.72	1.98	1.16	1.70	2.11	1.26	1.68	2.24	1.36	1.66	2.39	1.46	1.63	2.55	96.46	65.90	74.28	0.00
NWN	1.92	1.07	1.79	1.99	1.15	1.73	2.07	1.23	1.68	2.16	1.32	1.63	2.24	1.42	1.58	2.33	72.61	51.26	59.68	0.00
SJI	1.11	1.06	1.04	1.14	1.13	1.01	1.17	1.20	0.97	1.21	1.28	0.94	1.25	1.36	0.91	1.28	38.68	28.39	33.27	0.00
SWX	1.84	1.06	1.73	1.91	1.13	1.69	1.99	1.20	1.65	2.07	1.28	1.61	2.15	1.36	1.58	2.23	93.68	68.74	76.99	0.00
SR	2.14	1.07	2.00	2.23	1.15	1.93	2.32	1.24	1.87	2.41	1.33	1.82	2.51	1.43	1.76	2.61	78.63	55.12	64.50	0.00
WGL	1.98	1.06	1.87	2.05	1.12	1.83	2.13	1.19	1.78	2.20	1.27	1.74	2.28	1.34	1.70	2.36	92.24	68.75	77.66	0.00

Sources and Notes:

[1] Appendix A, Exhibit 2, Schedule 6
[2] Appendix A, Exhibit 2, Schedule 6
[3] = [2] / [1]
[4] Appendix A, Exhibit 2, Schedule 5
[5] = [3] x (1 + 0.5 x [4])
[6] if [4] is less than Group Avg. less St. Dev. (3.07%), then equal to 3.07%',
if [4] is greater than Group Avg. plu St. Dev. (5.28%), then equal to 5.28%
else equal to [4]
[7] ROE that sets [1] equal to [26]; solved using Excel's Goal Seek function
Adjustment for Flotation costs: ROE = [7] - [5] + [5]/(1-F)
[8] = [1] x [5]
[9] = (1 + [7])^1
[10] = [8] / [9]
[11] = [8] x (1 + [4])
[12] = (1 + [7])^2
[13] = [11] / [12]
(continued)

Sources and Notes, Continued:

[14] = [11] x (1 + [4])
[15] = (1 + [7])^3
[16] = [14] / [15]
[17] = [14] x (1 + [4])
[18] = (1 + [7])^4
[19] = [17] / [18]
[20] = [17] x (1 + [4])
[21] = (1 + [7])^5
[22] = [20] / [21]
[23] = [20] x (1 + [6])
[24] = [23] / ([7] - [6])
[25] = [24] / [21]
[26] = [10] + [13] + [16] + [19] + [22] + [25]
[27] = [26] - [1]

Two Growth Rate DCF Analysis - DOC Final Natural Gas Proxy Group
Mean Growth Rates

Ticker	Average Closing Price	Annualized Dividend	Dividend Yield	Mean Projected Growth Rate	Mean Expected Dividend Yield	Second Growth Rate		Mean Expected ROE
	[1]	[2]	[3]	[4]	[5]	[6]		[7]
ATO	74.28	1.80	2.42%	6.93%	2.51%	6.59%		9.14%
NWN	59.68	1.88	3.15%	5.13%	3.23%	5.29%		8.50%
SJI	33.27	1.09	3.28%	6.33%	3.38%	6.33%		9.71%
SWX	77.00	1.80	2.34%	5.15%	2.40%	5.29%		7.67%
SR	64.50	2.10	3.26%	5.82%	3.35%	5.82%		9.17%
WGL	77.66	1.95	2.51%	6.28%	2.59%	6.28%		8.87%
Mean			2.83%	5.94%	2.91%	5.93%		8.84%
With Flotation Costs								8.93%
		Average		5.94%				
		Std. Dev.		0.65%			Flotation Costs (F)	2.93%
		Avg. less St. Dev.		5.29%				
		Avg. plus St. Dev		6.59%				

Ticker	Year 1 Div.	(1+k)^1	PV of Year 1 Div.	Year 2 Div.	(1+k)^2	PV of Year 2 Div.	Year 3 Div.	(1+k)^3	PV of Year 3 Div.	Year 4 Div.	(1+k)^4	PV of Year 4 Div.	Year 5 Div.	(1+k)^5	PV of Year 5 Div.	Year 6 Div.	Year 5 Stock Price	PV of Year 5 Stock Price	Current Stock Price	CHECK
	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]
ATO	1.86	1.09	1.71	1.99	1.19	1.67	2.13	1.30	1.64	2.28	1.42	1.61	2.44	1.55	1.57	2.60	102.32	66.09	74.28	(0.00)
NWN	1.93	1.08	1.78	2.03	1.18	1.72	2.13	1.28	1.67	2.24	1.39	1.62	2.36	1.50	1.57	2.48	77.17	51.33	59.68	(0.00)
SJI	1.12	1.10	1.02	1.20	1.20	0.99	1.27	1.32	0.96	1.35	1.45	0.93	1.44	1.59	0.90	1.53	45.23	28.45	33.27	0.00
SWX	1.85	1.08	1.71	1.94	1.16	1.67	2.04	1.25	1.64	2.15	1.34	1.60	2.26	1.45	1.56	2.37	99.59	68.81	77.00	0.00
SR	2.16	1.09	1.98	2.29	1.19	1.92	2.42	1.30	1.86	2.56	1.42	1.80	2.71	1.55	1.75	2.87	85.57	55.19	64.50	(0.00)
WGL	2.01	1.09	1.85	2.14	1.19	1.80	2.27	1.29	1.76	2.41	1.40	1.72	2.57	1.53	1.68	2.73	105.29	68.85	77.66	0.00

Sources and Notes:

[1] Appendix A, Exhibit 2, Schedule 6
[2] Appendix A, Exhibit 2, Schedule 6
[3] = [2] / [1]
[4] Appendix A, Exhibit 2, Schedule 5
[5] = [3] x (1 + 0.5 x [4])
[6] if [4] is less than Group Avg. less St. Dev. (5.29%), then equal to 5.29%',
if [4] is greater than Group Avg. plu St. Dev. (6.59%), then equal to 6.59%
else equal to [4]
[7] ROE that sets [1] equal to [26]; solved using Excel's Goal Seek function
Adjustment for Flotation costs: ROE = [7] - [5] + [5]/(1-F)
[8] = [1] x [5]
[9] = (1 + [7])^1
[10] = [8] / [9]
[11] = [8] x (1 + [4])
[12] = (1 + [7])^2
[13] = [11] / [12]
(continued)

Sources and Notes, Continued:

[14] = [11] x (1 + [4])
[15] = (1 + [7])^3
[16] = [14] / [15]
[17] = [14] x (1 + [4])
[18] = (1 + [7])^4
[19] = [17] / [18]
[20] = [17] x (1 + [4])
[21] = (1 + [7])^5
[22] = [20] / [21]
[23] = [20] x (1 + [6])
[24] = [23] / ([7] - [6])
[25] = [24] / [21]
[26] = [10] + [13] + [16] + [19] + [22] + [25]
[27] = [26] - [1]

Two Growth Rate DCF Analysis - DOC Final Natural Gas Proxy Group
High Growth Rates

Ticker	Average Closing Price	Annualized Dividend	Dividend Yield	High Projected Growth Rate	High Expected Dividend Yield	Second Growth Rate	High Expected ROE
	[1]	[2]	[3]	[4]	[5]	[6]	[7]
ATO	74.28	1.80	2.42%	7.30%	2.51%	7.30%	9.81%
NWN	59.68	1.88	3.15%	7.00%	3.26%	7.00%	10.26%
SJI	33.27	1.09	3.28%	10.00%	3.44%	9.17%	12.73%
SWX	77.00	1.80	2.34%	7.00%	2.42%	7.00%	9.42%
SR	64.50	2.10	3.26%	9.00%	3.40%	9.00%	12.40%
WGL	77.66	1.95	2.51%	8.00%	2.61%	8.00%	10.61%
Mean			2.83%	8.05%	2.94%	7.91%	10.87%
With Flotation Costs							10.96%
		Average		8.05%			
		Std. Dev.		1.12%		Flotation Costs (F)	2.93%
		Avg. less St. Dev.		6.93%			
		Avg. plus St. Dev		9.17%			

Ticker	Year 1 Div.	(1+k)^1	PV of Year 1 Div.	Year 2 Div.	(1+k)^2	PV of Year 2 Div.	Year 3 Div.	(1+k)^3	PV of Year 3 Div.	Year 4 Div.	(1+k)^4	PV of Year 4 Div.	Year 5 Div.	(1+k)^5	PV of Year 5 Div.	Year 6 Div.	Year 5 Stock Price	PV of Year 5 Stock Price	Current Stock Price	CHECK
	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]
ATO	1.87	1.10	1.70	2.00	1.21	1.66	2.15	1.32	1.62	2.30	1.45	1.59	2.47	1.60	1.55	2.65	105.65	66.17	74.28	0.00
NWN	1.95	1.10	1.76	2.08	1.22	1.71	2.23	1.34	1.66	2.38	1.48	1.61	2.55	1.63	1.57	2.73	83.70	51.36	59.68	0.00
SJI	1.14	1.13	1.02	1.26	1.27	0.99	1.38	1.43	0.97	1.52	1.61	0.94	1.68	1.82	0.92	1.84	51.76	28.43	33.27	0.00
SWX	1.86	1.09	1.70	1.99	1.20	1.66	2.13	1.31	1.63	2.28	1.43	1.59	2.44	1.57	1.56	2.61	107.99	68.85	76.99	0.00
SR	2.19	1.12	1.95	2.39	1.26	1.89	2.61	1.42	1.84	2.84	1.60	1.78	3.10	1.79	1.73	3.38	99.24	55.31	64.50	0.00
WGL	2.03	1.11	1.83	2.19	1.22	1.79	2.37	1.35	1.75	2.55	1.50	1.71	2.76	1.66	1.67	2.98	114.11	68.92	77.66	0.00

Sources and Notes:

[1] Appendix A, Exhibit 2, Schedule 6
[2] Appendix A, Exhibit 2, Schedule 6
[3] = [2] / [1]
[4] Appendix A, Exhibit 2, Schedule 5
[5] = [3] x (1 + 0.5 x [4])
[6] If [4] is less than Group Avg. less St. Dev. (6.93%), then equal to 6.93%',
if [4] is greater than Group Avg. plu St. Dev. (9.17%), then equal to 9.17%
else equal to [4]
[7] ROE that sets [1] equal to [26]; solved using Excel's Goal Seek function
Adjustment for Flotation costs: ROE = [7] - [5] + [5]/(1-F)
[8] = [1] x [5]
[9] = (1 + [7])^1
[10] = [8] / [9]
[11] = [8] x (1 + [4])
[12] = (1 + [7])^2
[13] = [11] / [12]
(continued)

Sources and Notes, Continued:

[14] = [11] x (1 + [4])
[15] = (1 + [7])^3
[16] = [14] / [15]
[17] = [14] x (1 + [4])
[18] = (1 + [7])^4
[19] = [17] / [18]
[20] = [17] x (1 + [4])
[21] = (1 + [7])^5
[22] = [20] / [21]
[23] = [20] x (1 + [6])
[24] = [23] / ([7] - [6])
[25] = [24] / [21]
[26] = [10] + [13] + [16] + [19] + [22] + [25]
[27] = [26] - [1]

Projected Growth Rates
DOC Natural Gas Proxy Group

Company	Ticker	Zacks	Thomson	Value Line	Low Projected Growth Rate	Mean Projected Growth Rate	High Projected Growth Rate
		[1]	[2]	[3]	[4]	[5]	[6]
Atmos Energy Corp	ATO	7.00%	7.30%	6.50%	6.50%	6.93%	7.30%
Northwest Natural Gas	NWN	4.00%	4.40%	7.00%	4.00%	5.13%	7.00%
South Jersey Industries	SJI	10.00%	6.00%	3.00%	3.00%	6.33%	10.00%
Southwest Gas Corp	SWX	4.45%	4.00%	7.00%	4.00%	5.15%	7.00%
Spire Inc	SR	4.41%	4.04%	9.00%	4.04%	5.82%	9.00%
WGL Holdings	WGL	7.33%	8.00%	3.50%	3.50%	6.28%	8.00%
Average		6.20%	5.62%	6.00%	4.17%	5.94%	8.05%

Sources and notes:

[1] Zacks Investment Research
[2] Thomson Financial Network; Accessed via Yahoo! Finance
[3] Value Line
[4] = min([1], [2], [3])
[5] = average([1], [2], [3])
[6] = max([1], [2], [3])

30-Day Average Closing Prices and Current Dividends
DOC Electric Proxy Group

	ATO	NWN	SJI	SWX	SR	WGL
Annualized Dividend	1.800	1.880	1.090	1.800	2.100	1.950
30 Day Average Closing Stock Price	74.28	59.68	33.27	77.00	64.50	77.66
Daily Closing Prices						
1/25/2017	74.98	59.35	32.01	78.92	64.65	78.78
1/24/2017	75.14	59.90	32.01	79.14	64.60	78.96
1/23/2017	74.39	58.80	32.00	78.49	64.70	78.33
1/20/2017	74.71	58.60	32.08	77.97	64.65	79.03
1/19/2017	74.26	58.60	32.02	77.37	64.30	78.34
1/18/2017	75.24	59.00	32.42	78.25	65.20	78.74
1/17/2017	74.74	59.15	32.18	78.00	65.30	78.78
1/13/2017	74.86	58.85	31.97	78.32	65.20	79.40
1/12/2017	74.51	58.65	31.99	78.44	64.60	80.26
1/11/2017	74.09	58.95	31.91	77.58	64.65	75.78
1/10/2017	73.29	58.40	31.50	76.86	63.85	75.04
1/9/2017	73.21	58.20	31.90	76.02	64.25	74.19
1/6/2017	74.17	59.45	33.38	77.60	65.00	75.50
1/5/2017	74.60	60.10	33.80	77.83	65.30	76.24
1/4/2017	74.97	60.55	34.21	78.44	65.60	77.05
1/3/2017	74.55	59.40	33.64	76.41	64.35	75.88
12/30/2016	74.15	59.80	33.69	76.62	64.55	76.28
12/29/2016	74.65	60.20	34.34	76.56	65.05	76.66
12/28/2016	73.69	59.65	33.81	75.43	64.05	76.40
12/27/2016	74.73	60.10	34.44	76.57	64.80	78.08
12/23/2016	74.61	59.95	34.24	76.04	64.65	77.92
12/22/2016	74.66	60.20	34.28	76.01	64.45	77.89
12/21/2016	74.27	59.95	34.33	76.06	64.20	77.97
12/20/2016	74.42	60.60	34.59	76.42	64.30	78.61
12/19/2016	74.11	61.50	34.68	76.48	64.65	79.79
12/16/2016	74.16	61.10	33.95	76.02	64.20	78.56
12/15/2016	73.00	60.45	34.17	75.69	63.25	77.71
12/14/2016	72.41	59.25	33.88	74.48	62.95	76.56
12/13/2016	73.95	61.30	34.65	76.64	63.85	78.87
12/12/2016	73.97	60.40	33.98	75.19	63.85	78.23

Source: Yahoo! Finance

Constant Growth DCF Analysis - DOC Combination Proxy Group

Company	Ticker	Average Closing Price	Annualized Dividend	Dividend Yield	Low Projected Growth Rate	Mean Projected Growth Rate	High Projected Growth Rate	Low Expected Dividend Yield	Mean Expected Dividend Yield	High Expected Dividend Yield	Low ROE	Mean ROE	High ROE
		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Ameren Corporation	AEE	52.08	1.76	3.38%	5.85%	6.12%	6.50%	3.48%	3.48%	3.49%	9.33%	9.60%	9.99%
Avista Corporation	AVA	39.94	1.37	3.43%	5.00%	5.33%	5.65%	3.52%	3.52%	3.53%	8.52%	8.85%	9.18%
CMS Energy Corporation	CMS	41.75	1.33	3.19%	6.00%	6.53%	7.60%	3.28%	3.29%	3.31%	9.28%	9.82%	10.91%
DTE Energy Company	DTE	98.29	3.30	3.36%	5.51%	5.78%	6.00%	3.45%	3.45%	3.46%	8.96%	9.23%	9.46%
NorthWestern Corporation	NWE	57.06	2.00	3.50%	4.34%	5.28%	6.50%	3.58%	3.60%	3.62%	7.92%	8.88%	10.12%
SCANA Corporation	SCG	72.59	2.30	3.17%	4.50%	5.29%	5.70%	3.24%	3.25%	3.26%	7.74%	8.54%	8.96%
Vectren Corporation	VVC	52.93	1.68	3.17%	5.33%	7.17%	9.00%	3.26%	3.29%	3.32%	8.59%	10.45%	12.32%
Wisconsin Energy Corporation	WEC	58.43	2.08	3.56%	6.00%	6.24%	6.73%	3.67%	3.67%	3.68%	9.67%	9.91%	10.41%
Mean				3.35%	5.32%	5.97%	6.71%	3.43%	3.44%	3.46%	8.75%	9.41%	10.17%
Required ROE including flotation cost adjustment											8.85%	9.52%	10.27%
Flotation Costs											2.93%		

Sources and Notes:
[1] Appendix A, Exhibit 2, Schedule 12
[2] Appendix A, Exhibit 2, Schedule 12
[3] = [2] / [1]
[4] Appendix A, Exhibit 2, Schedule 11
[5] Appendix A, Exhibit 2, Schedule 11
[6] Appendix A, Exhibit 2, Schedule 11
[7] = [3] x (1 + 0.5 x [4])
[8] = [3] x (1 + 0.5 x [5])
[9] = [3] x (1 + 0.5 x [6])
[10] = [4] + [7]
[11] = [5] + [8]
[12] = [6] + [9]

Two Growth Rate DCF Analysis - DOC Final Combination Proxy Group
Low Growth Rates

Ticker	Average Closing Price	Annualized Dividend	Dividend Yield	Low Projected Growth Rate	Low Expected Dividend Yield	Second Growth Rate		Low Expected ROE
	[1]	[2]	[3]	[4]	[5]	[6]		[7]
AEE	52.08	1.76	3.38%	5.85%	3.48%	5.85%		9.33%
AVA	39.94	1.37	3.43%	5.00%	3.52%	5.00%		8.52%
CMS	41.75	1.33	3.19%	6.00%	3.28%	5.93%		9.22%
DTE	98.29	3.30	3.36%	5.51%	3.45%	5.51%		8.96%
NWE	57.06	2.00	3.50%	4.34%	3.58%	4.71%		8.23%
SCG	72.59	2.30	3.17%	4.50%	3.24%	4.71%		7.92%
WC	52.93	1.68	3.17%	5.33%	3.26%	5.33%		8.59%
WEC	58.43	2.08	3.56%	6.00%	3.67%	5.93%		9.60%
Mean			3.35%	5.32%	3.43%	5.37%		8.80%
With Flotation Costs								8.90%
		Average		5.32%				
		Std. Dev.		0.61%			Flotation Costs (F)	2.93%
		Avg. less St. Dev.		4.71%				
		Avg. plus St. Dev		5.93%				

Ticker	Year 1 Div.	(1+k)^1	PV of Year 1 Div.	Year 2 Div.	(1+k)^2	PV of Year 2 Div.	Year 3 Div.	(1+k)^3	PV of Year 3 Div.	Year 4 Div.	(1+k)^4	PV of Year 4 Div.	Year 5 Div.	(1+k)^5	PV of Year 5 Div.	Year 6 Div.	Year 5 Stock Price	PV of Year 5 Stock Price	Current Stock Price	CHECK
	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]
AEE	1.81	1.09	1.66	1.92	1.20	1.60	2.03	1.31	1.55	2.15	1.43	1.50	2.27	1.56	1.46	2.41	69.20	44.31	52.08	0.00
AVA	1.40	1.09	1.29	1.47	1.18	1.25	1.55	1.28	1.21	1.63	1.39	1.17	1.71	1.50	1.13	1.79	50.97	33.87	39.94	0.00
CMS	1.37	1.09	1.25	1.45	1.19	1.22	1.54	1.30	1.18	1.63	1.42	1.15	1.73	1.55	1.11	1.83	55.70	35.84	41.75	0.00
DTE	3.39	1.09	3.11	3.58	1.19	3.01	3.77	1.29	2.92	3.98	1.41	2.83	4.20	1.54	2.74	4.43	128.52	83.68	98.29	0.00
NWE	2.04	1.08	1.89	2.13	1.17	1.82	2.22	1.27	1.75	2.32	1.37	1.69	2.42	1.49	1.63	2.53	71.70	48.28	57.06	0.00
SCG	2.35	1.08	2.18	2.46	1.16	2.11	2.57	1.26	2.04	2.68	1.36	1.98	2.80	1.46	1.92	2.93	91.27	62.36	72.59	0.00
WC	1.72	1.09	1.59	1.82	1.18	1.54	1.91	1.28	1.49	2.02	1.39	1.45	2.12	1.51	1.41	2.24	68.62	45.45	52.93	0.00
WEC	2.14	1.10	1.95	2.27	1.20	1.89	2.41	1.32	1.83	2.55	1.44	1.77	2.70	1.58	1.71	2.87	77.95	49.28	58.43	0.00

Sources and Notes:

[1] Appendix A, Exhibit 2, Schedule 12
[2] Appendix A, Exhibit 2, Schedule 12
[3] = [2] / [1]
[4] Appendix A, Exhibit 2, Schedule 11
[5] = [3] x (1 + 0.5 x [4])
[6] if [4] is less than Group Avg. less St. Dev. (4.71%), then equal to 4.71%',
if [4] is greater than Group Avg. plu St. Dev. (5.93%), then equal to 5.93%
else equal to [4]
[7] ROE that sets [1] equal to [26]; solved using Excel's Goal Seek function
Adjustment for Flotation costs: ROE = [7] - [5] + [5]/(1-F)
[8] = [1] x [5]
[9] = (1 + [7])^1
[10] = [8] / [9]
[11] = [8] x (1 + [4])
[12] = (1 + [7])^2
[13] = [11] / [12]
(continued)

Sources and Notes, Continued:

[14] = [11] x (1 + [4])
[15] = (1 + [7])^3
[16] = [14] / [15]
[17] = [14] x (1 + [4])
[18] = (1 + [7])^4
[19] = [17] / [18]
[20] = [17] x (1 + [4])
[21] = (1 + [7])^5
[22] = [20] / [21]
[23] = [20] x (1 + [6])
[24] = [23] / ([7] - [6])
[25] = [24] / [21]
[26] = [10] + [13] + [16] + [19] + [22] + [25]
[27] = [26] - [1]

Two Growth Rate DCF Analysis - DOC Final Combination Proxy Group
Mean Growth Rates

Ticker	Average Closing Price	Annualized Dividend	Dividend Yield	Mean Projected Growth Rate	Mean Expected Dividend Yield	Second Growth Rate		Mean Expected ROE
	[1]	[2]	[3]	[4]	[5]	[6]		[7]
AEE	52.08	1.76	3.38%	6.12%	3.48%	6.12%		9.60%
AVA	39.94	1.37	3.43%	5.33%	3.52%	5.33%		8.85%
CMS	41.75	1.33	3.19%	6.53%	3.29%	6.53%		9.82%
DTE	98.29	3.30	3.36%	5.78%	3.45%	5.78%		9.23%
NWE	57.06	2.00	3.50%	5.28%	3.60%	5.33%		8.92%
SCG	72.59	2.30	3.17%	5.29%	3.25%	5.33%		8.58%
WC	52.93	1.68	3.17%	7.17%	3.29%	6.60%		9.97%
WEC	58.43	2.08	3.56%	6.24%	3.67%	6.24%		9.91%
Mean			3.35%	5.97%	3.44%	5.91%		9.36%
With Flotation Costs								9.47%
		Average		5.97%				
		Std. Dev.		0.64%			Flotation Costs (F)	2.93%
		Avg. less St. Dev.		5.33%				
		Avg. plus St. Dev		6.60%				

Ticker	Year 1 Div.	(1+k)^1	PV of Year 1 Div.	Year 2 Div.	(1+k)^2	PV of Year 2 Div.	Year 3 Div.	(1+k)^3	PV of Year 3 Div.	Year 4 Div.	(1+k)^4	PV of Year 4 Div.	Year 5 Div.	(1+k)^5	PV of Year 5 Div.	Year 6 Div.	Year 5 Stock Price	PV of Year 5 Stock Price	Current Stock Price	CHECK
	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]
AEE	1.81	1.10	1.65	1.92	1.20	1.60	2.04	1.32	1.55	2.17	1.44	1.50	2.30	1.58	1.45	2.44	70.08	44.31	52.08	0.00
AVA	1.41	1.09	1.29	1.48	1.18	1.25	1.56	1.29	1.21	1.64	1.40	1.17	1.73	1.53	1.13	1.82	51.78	33.88	39.94	0.00
CMS	1.37	1.10	1.25	1.46	1.21	1.21	1.56	1.32	1.18	1.66	1.45	1.14	1.77	1.60	1.11	1.88	57.29	35.86	41.75	0.00
DTE	3.40	1.09	3.11	3.59	1.19	3.01	3.80	1.30	2.91	4.02	1.42	2.82	4.25	1.56	2.73	4.50	130.17	83.70	98.29	0.00
NWE	2.05	1.09	1.88	2.16	1.19	1.82	2.28	1.29	1.76	2.40	1.41	1.70	2.52	1.53	1.65	2.66	73.96	48.25	57.06	0.00
SCG	2.36	1.09	2.17	2.49	1.18	2.11	2.62	1.28	2.04	2.76	1.39	1.98	2.90	1.51	1.92	3.05	94.09	62.35	72.59	0.00
WC	1.74	1.10	1.58	1.86	1.21	1.54	2.00	1.33	1.50	2.14	1.46	1.46	2.30	1.61	1.43	2.46	73.04	45.41	52.93	0.00
WEC	2.14	1.10	1.95	2.28	1.21	1.89	2.42	1.33	1.82	2.57	1.46	1.76	2.73	1.60	1.70	2.90	79.10	49.30	58.43	0.00

Sources and Notes:

[1] Appendix A, Exhibit 2, Schedule 12
[2] Appendix A, Exhibit 2, Schedule 12
[3] = [2] / [1]
[4] Appendix A, Exhibit 2, Schedule 11
[5] = [3] x (1 + 0.5 x [4])
[6] if [4] is less than Group Avg. less St. Dev. (5.33%), then equal to 5.33%',
if [4] is greater than Group Avg. plu St. Dev. (6.60%), then equal to 6.60%
else equal to [4]
[7] ROE that sets [1] equal to [26]; solved using Excel's Goal Seek function
Adjustment for Flotation costs: ROE = [7] - [5] + [5]/(1-F)
[8] = [1] x [5]
[9] = (1 + [7])^1
[10] = [8] / [9]
[11] = [8] x (1 + [4])
[12] = (1 + [7])^2
[13] = [11] / [12]
(continued)

Sources and Notes, Continued:

[14] = [11] x (1 + [4])
[15] = (1 + [7])^3
[16] = [14] / [15]
[17] = [14] x (1 + [4])
[18] = (1 + [7])^4
[19] = [17] / [18]
[20] = [17] x (1 + [4])
[21] = (1 + [7])^5
[22] = [20] / [21]
[23] = [20] x (1 + [6])
[24] = [23] / ([7] - [6])
[25] = [24] / [21]
[26] = [10] + [13] + [16] + [19] + [22] + [25]
[27] = [26] - [1]

Two Growth Rate DCF Analysis - DOC Final Combination Proxy Group
High Growth Rates

Ticker	Average Closing Price	Annualized Dividend	Dividend Yield	High Projected Growth Rate	High Expected Dividend Yield	Second Growth Rate		High Expected ROE
	[1]	[2]	[3]	[4]	[5]	[6]		[7]
AEE	52.08	1.76	3.38%	6.50%	3.49%	6.50%		9.99%
AVA	39.94	1.37	3.43%	5.65%	3.53%	5.66%		9.19%
CMS	41.75	1.33	3.19%	7.60%	3.31%	7.60%		10.91%
DTE	98.29	3.30	3.36%	6.00%	3.46%	6.00%		9.46%
NWE	57.06	2.00	3.50%	6.50%	3.62%	6.50%		10.12%
SCG	72.59	2.30	3.17%	5.70%	3.26%	5.70%		8.96%
VVC	52.93	1.68	3.17%	9.00%	3.32%	7.76%		11.25%
WEC	58.43	2.08	3.56%	6.73%	3.68%	6.73%		10.41%
Mean			3.35%	6.71%	3.46%	6.56%		10.04%
With Flotation Costs								10.14%
		Average		6.71%				
		Std. Dev.		1.05%			Flotation Costs (F)	2.93%
		Avg. less St. Dev.		5.66%				
		Avg. plus St. Dev		7.76%				

Ticker	Year 1 Div.	(1+k)^1	PV of Year 1 Div.	Year 2 Div.	(1+k)^2	PV of Year 2 Div.	Year 3 Div.	(1+k)^3	PV of Year 3 Div.	Year 4 Div.	(1+k)^4	PV of Year 4 Div.	Year 5 Div.	(1+k)^5	PV of Year 5 Div.	Year 6 Div.	Year 5 Stock Price	PV of Year 5 Stock Price	Current Stock Price	CHECK
	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]
AEE	1.82	1.10	1.65	1.94	1.21	1.60	2.06	1.33	1.55	2.20	1.46	1.50	2.34	1.61	1.45	2.49	71.35	44.33	52.08	0.00
AVA	1.41	1.09	1.29	1.49	1.19	1.25	1.57	1.30	1.21	1.66	1.42	1.17	1.76	1.55	1.13	1.85	52.60	33.89	39.94	0.00
CMS	1.38	1.11	1.24	1.49	1.23	1.21	1.60	1.36	1.17	1.72	1.51	1.14	1.85	1.68	1.10	1.99	60.22	35.89	41.75	0.00
DTE	3.40	1.09	3.11	3.60	1.20	3.01	3.82	1.31	2.91	4.05	1.44	2.82	4.29	1.57	2.73	4.55	131.53	83.71	98.29	0.00
NWE	2.07	1.10	1.88	2.20	1.21	1.81	2.34	1.34	1.75	2.49	1.47	1.70	2.66	1.62	1.64	2.83	78.18	48.28	57.06	0.00
SCG	2.37	1.09	2.17	2.50	1.19	2.11	2.64	1.29	2.04	2.79	1.41	1.98	2.95	1.54	1.92	3.12	95.77	62.36	72.59	0.00
VVC	1.76	1.11	1.58	1.91	1.24	1.55	2.09	1.38	1.51	2.27	1.53	1.48	2.48	1.70	1.45	2.70	77.29	45.35	52.93	0.00
WEC	2.15	1.10	1.95	2.29	1.22	1.88	2.45	1.35	1.82	2.61	1.49	1.76	2.79	1.64	1.70	2.98	80.93	49.32	58.43	0.00

Sources and Notes:

[1] Appendix A, Exhibit 2, Schedule 12
[2] Appendix A, Exhibit 2, Schedule 12
[3] = [2] / [1]
[4] Appendix A, Exhibit 2, Schedule 11
[5] = [3] x (1 + 0.5 x [4])
[6] if [4] is less than Group Avg. less St. Dev. (5.66%), then equal to 5.66%',
if [4] is greater than Group Avg. plu St. Dev. (7.76%), then equal to 7.76%
else equal to [4]
[7] ROE that sets [1] equal to [26]; solved using Excel's Goal Seek function
Adjustment for Flotation costs: ROE = [7] - [5] + [5]/(1-F)
[8] = [1] x [5]
[9] = (1 + [7])^1
[10] = [8] / [9]
[11] = [8] x (1 + [4])
[12] = (1 + [7])^2
[13] = [11] / [12]
(continued)

Sources and Notes, Continued:

[14] = [11] x (1 + [4])
[15] = (1 + [7])^3
[16] = [14] / [15]
[17] = [14] x (1 + [4])
[18] = (1 + [7])^4
[19] = [17] / [18]
[20] = [17] x (1 + [4])
[21] = (1 + [7])^5
[22] = [20] / [21]
[23] = [20] x (1 + [6])
[24] = [23] / ([7] - [6])
[25] = [24] / [21]
[26] = [10] + [13] + [16] + [19] + [22] + [25]
[27] = [26] - [1]

Projected Growth Rates
DOC Combination Proxy Group

Company	Ticker	Zacks	Thomson	Value Line	Low Projected Growth Rate	Mean Projected Growth Rate	High Projected Growth Rate
		[1]	[2]	[3]	[4]	[5]	[6]
Ameren Corporation	AEE	5.85%	6.50%	6.00%	5.85%	6.12%	6.50%
Avista Corporation	AVA	NA	5.65%	5.00%	5.00%	5.33%	5.65%
CMS Energy Corporation	CMS	6.00%	7.60%	6.00%	6.00%	6.53%	7.60%
DTE Energy Company	DTE	5.83%	5.51%	6.00%	5.51%	5.78%	6.00%
NorthWestern Corporation	NWE	5.00%	4.34%	6.50%	4.34%	5.28%	6.50%
SCANA Corporation	SCG	5.67%	5.70%	4.50%	4.50%	5.29%	5.70%
Vectren Corporation	VVC	5.33%	na	9.00%	5.33%	7.17%	9.00%
Wisconsin Energy Corporation	WEC	6.00%	6.73%	6.00%	6.00%	6.24%	6.73%
Average		5.67%	6.00%	6.13%	5.32%	5.97%	6.71%

Sources and notes:
[1] Zacks Investment Research
[2] Thomson Financial Network; Accessed via Yahoo! Finance
[3] Value Line
[4] = min([1], [2], [3])
[5] = average([1], [2], [3])
[6] = max([1], [2], [3])

30-Day Average Closing Prices and Current Dividends
DOC Combination Proxy Group

	AEE	AVA	CMS	DTE	NWE	SCG	VVC	WEC
Annualized Dividend	1.760	1.370	1.330	3.300	2.000	2.300	1.680	2.080
30 Day Average Closing Stock Price	52.08	39.94	41.75	98.29	57.06	72.59	52.93	58.43
Daily Closing Prices								
1/25/2017	51.90	38.84	41.81	97.94	57.02	69.35	54.61	58.14
1/24/2017	52.06	39.18	41.97	97.96	57.38	69.72	54.57	58.43
1/23/2017	51.98	39.16	42.29	98.03	57.09	70.30	54.23	58.39
1/20/2017	52.05	39.33	42.33	98.40	57.15	70.85	54.23	58.50
1/19/2017	51.81	39.02	42.13	98.14	56.87	70.99	54.24	58.56
1/18/2017	52.36	39.50	42.19	98.89	57.45	72.36	54.71	59.38
1/17/2017	52.55	39.43	42.20	99.20	57.34	72.54	54.69	59.35
1/13/2017	51.97	39.35	41.94	98.30	57.16	72.06	54.46	58.74
1/12/2017	51.96	39.15	41.90	98.37	57.22	71.99	54.10	58.70
1/11/2017	52.20	39.50	41.95	98.41	57.41	71.49	53.33	58.65
1/10/2017	51.97	39.10	41.51	97.43	56.77	71.02	52.51	58.10
1/9/2017	51.99	39.02	41.58	97.88	56.41	70.93	52.42	57.98
1/6/2017	53.10	39.69	42.15	98.86	57.51	71.90	52.77	58.78
1/5/2017	52.70	39.87	41.99	98.60	57.24	72.40	52.30	59.02
1/4/2017	52.44	39.80	41.76	98.47	57.00	73.28	52.07	58.94
1/3/2017	52.38	39.71	41.53	98.21	56.66	73.25	51.72	58.49
12/30/2016	52.46	39.99	41.62	98.51	56.87	73.28	52.15	58.65
12/29/2016	52.56	40.18	41.77	98.93	57.03	73.61	52.40	58.85
12/28/2016	51.82	39.47	41.30	97.93	56.52	72.92	51.72	57.90
12/27/2016	52.56	39.99	41.69	98.65	57.15	74.43	52.67	58.57
12/23/2016	52.45	39.71	41.70	98.74	57.18	74.69	52.75	58.73
12/22/2016	52.41	39.49	41.59	98.51	57.17	74.50	52.63	58.71
12/21/2016	51.95	39.67	41.56	98.21	57.10	74.23	52.45	58.46
12/20/2016	52.19	40.05	41.71	98.62	57.31	74.43	52.51	58.45
12/19/2016	51.89	40.23	41.89	98.28	57.15	74.25	52.40	58.16
12/16/2016	51.60	40.77	41.50	98.20	56.93	74.03	52.38	58.01
12/15/2016	51.10	42.17	40.90	96.69	56.66	72.94	52.06	57.14
12/14/2016	50.70	41.63	40.82	96.91	56.29	72.67	51.41	56.91
12/13/2016	51.92	42.63	41.53	98.91	57.29	73.99	51.95	58.32
12/12/2016	51.34	42.48	41.72	98.42	57.53	73.18	51.48	57.94

Source: Yahoo! Finance

DOC Calculation of Flotation Cost Percentage

Total Flotation Costs	[a]	115,016,648
Gross Equity Before Costs - Public	[b]	2,491,285,237
Gross Equity Before Costs - Non-Public	[c]	1,548,782,000
Total Gross Equity	[d] = [b] + [c]	4,040,067,237
Flotation Cost Percentage (F)	[e] = [a] / [d]	2.93%

Source: Exhibit __ (BVA-1), Schedule 13 (Van Abel Direct)

DOC CAPM Analyses for DOC Natural Gas and Combination Proxy Groups

	Line No.	Formula/Note	
CAPM Estimate for DOC Natural Gas Proxy Group			
Risk-free Rate	[1]	Appendix A, Exhibit 3, Schedule 2	2.79%
SPDR S&P 500 ETF	[2]	SPDR Website as of February 7, 2017	11.22%
Dividend Yield on S&P 500	[3]	SPDR Website as of February 7, 2017	1.98%
Dividend Yield on S&P 500 with One Half Years' Worth of Growth	[4]	= [3] x (1+[2])^0.5	2.09%
DCF Required Market Return	[5]	= [2] + [4]	13.31%
β for DOC LDC Comparable Group	[6]	Appendix A, Exhibit 3, Schedule 3	0.73
Required Return for DOC Natural Gas Proxy Group	[7]	= [1] + [6] x ([5] - [1])	10.42%
Flotation Cost Adjustment	[8]	Appendix A, Exhibit 2, Schedule 13	0.09%
Simple CAPM with Flotation Costs	[9]	= [7] = [8]	10.51%
CAPM Estimate for DOC Combination Proxy Group			
Risk-free Rate	[1]	Appendix A, Exhibit 3, Schedule 2	2.79%
SPDR S&P 500 ETF	[2]	SPDR Website as of February 7, 2017	11.22%
Dividend Yield on S&P 500	[3]	SPDR Website as of February 7, 2017	1.98%
Dividend Yield on S&P 500 with One Half Years' Worth of Growth	[4]	= [3] x (1+[2])^0.5	2.09%
DCF Required Market Return	[5]	= [2] + [4]	13.31%
β for DOC LDC Comparable Group	[6]	Appendix A, Exhibit 3, Schedule 3	0.71
Required Return for DOC Combination Proxy Group	[7]	= [1] + [6] x ([5] - [1])	10.24%
Flotation Cost Adjustment	[8]	Appendix A, Exhibit 2, Schedule 13	0.09%
Simple CAPM with Flotation Costs	[9]	= [7] = [8]	10.33%

20-Year Treasury
Constant Maturity Date

Line No.	Date	Rate
		(%)
1.	2016-12-12	2.86
2.	2016-12-13	2.85
3.	2016-12-14	2.86
4.	2016-12-15	2.89
5.	2016-12-16	2.91
6.	2016-12-19	2.85
7.	2016-12-20	2.88
8.	2016-12-21	2.86
9.	2016-12-22	2.86
10.	2016-12-23	2.86
11.	2016-12-27	2.88
12.	2016-12-28	2.83
13.	2016-12-29	2.82
14.	2016-12-30	2.79
15.	2017-01-03	2.78
16.	2017-01-04	2.78
17.	2017-01-05	2.69
18.	2017-01-06	2.73
19.	2017-01-09	2.69
20.	2017-01-10	2.69
21.	2017-01-11	2.68
22.	2017-01-12	2.68
23.	2017-01-13	2.71
24.	2017-01-17	2.66
25.	2017-01-18	2.74
26.	2017-01-19	2.77
27.	2017-01-20	2.79
28.	2017-01-23	2.72
29.	2017-01-24	2.78
30.	2017-01-25	2.84
	Average	2.79

Source:
Federal Reserve Bank of St. Louis

**Value Line Betas
For Member of
DOC LDC Proxy Group**

Line No.	Ticker	β
1.	ATO	0.70
2.	NWN	0.65
3.	SJI	0.80
4.	SWX	0.75
5.	SP	0.70
6.	WGL	0.75
7.	Average	0.73

**Value Line Betas
For Member of
DOC LDC Proxy Group**

	Ticker	0	β
8.	AEE		0.65
9.	AVA		0.70
10.	CNP		0.85
11.	CMS		0.65
12.	DTE		0.65
13.	NI		NA
14.	NWE		0.70
15.	SCG		0.70
16.	VVC		0.75
17.	WEC		0.60
	Average		0.71

Constant Growth Discounted Cash Flow Model - LDC Proxy Group
30 Day Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] First Call Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE	[12] Low Dividend Yield	[13] Mean Dividend Yield	[14] High Dividend Yield
Atmos Energy Corporation	ATO	$1.68	$74.70	2.25%	2.33%	7.20%	7.30%	6.50%	7.00%	8.82%	9.33%	9.63%	2.32%	2.33%	2.33%
Northwest Natural Gas Company	NWN	$1.87	$60.69	3.08%	3.16%	4.00%	4.00%	7.00%	5.00%	7.14%	8.16%	10.19%	3.14%	3.16%	3.19%
South Jersey Industries, Inc.	SJI	$1.06	$29.80	3.54%	3.65%	10.00%	6.00%	3.00%	6.33%	6.59%	9.99%	13.72%	3.59%	3.65%	3.72%
Southwest Gas Corporation	SWX	$1.80	$70.95	2.54%	2.60%	4.50%	4.00%	7.00%	5.17%	6.59%	7.77%	9.63%	2.59%	2.60%	2.63%
Spire Inc	SR	$1.96	$64.95	3.02%	3.11%	4.60%	4.52%	9.00%	6.04%	7.61%	9.15%	12.15%	3.09%	3.11%	3.15%
WGL Holdings, Inc.	WGL	$1.95	$63.30	3.08%	3.18%	7.30%	8.00%	3.50%	6.27%	6.63%	9.44%	11.20%	3.13%	3.18%	3.20%
Proxy Group Mean				2.92%	3.00%	6.27%	5.64%	6.00%	5.97%	7.23%	8.97%	11.09%	2.98%	3.00%	3.04%
With Flotation Costs										7.32%	9.06%	11.18%			
Flotation Costs									2.93%						

Notes:
[1] Source: Bloomberg Professional Service
[2] Source: Bloomberg Professional Service, equals indicated number of trading day average as of September 30, 2016
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])
[12] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7]))
[13] Equals [3] x (1 + 0.5 x [8])
[14] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7]))

Constant Growth Discounted Cash Flow Model - Combination Proxy Group
30 Day Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] First Call Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE	[12] Low Dividend Yield	[13] Mean Dividend Yield	[14] High Dividend Yield
Ameren Corporation	AEE	$1.70	$49.86	3.41%	3.51%	6.10%	5.20%	6.00%	5.77%	8.70%	9.27%	9.61%	3.50%	3.51%	3.51%
Avista Corporation	AVA	$1.37	$41.72	3.28%	3.37%	5.30%	5.00%	5.00%	5.10%	8.37%	8.47%	8.67%	3.37%	3.37%	3.37%
CMS Energy Corporation	CMS	$1.24	$42.58	2.91%	3.01%	6.60%	7.27%	6.00%	6.62%	9.00%	9.63%	10.29%	3.00%	3.01%	3.02%
DTE Energy Company	DTE	$3.08	$93.94	3.28%	3.37%	5.80%	5.51%	6.00%	5.77%	8.88%	9.14%	9.38%	3.37%	3.37%	3.38%
NorthWestern Corporation	NWE	$2.00	$58.45	3.42%	3.52%	5.00%	5.00%	6.50%	5.50%	8.51%	9.02%	10.03%	3.51%	3.52%	3.53%
SCANA Corporation	SCG	$2.30	$72.11	3.19%	3.27%	5.50%	6.00%	4.50%	5.33%	7.76%	8.61%	9.29%	3.26%	3.27%	3.29%
Vectren Corporation	VVC	$1.60	$49.85	3.21%	3.31%	5.30%	5.00%	9.00%	6.43%	8.29%	9.75%	12.35%	3.29%	3.31%	3.35%
Wisconsin Energy Corporation	WEC	$1.98	$60.90	3.25%	3.35%	6.20%	6.72%	6.00%	6.31%	9.35%	9.66%	10.08%	3.35%	3.35%	3.36%
Proxy Group Mean				3.24%	3.34%	5.73%	5.71%	6.13%	5.85%	8.61%	9.19%	9.96%	3.33%	3.34%	3.35%
With Flotation Costs										8.71%	9.29%	10.06%			
Flotation Costs									2.93%						

Notes:
[1] Source: Bloomberg Professional Service
[2] Source: Bloomberg Professional Service, equals indicated number of trading day average as of September 30, 2016
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])
[12] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7]))

Two Growth Rate DCF Analysis with Flotation Costs - Average Growth Rate
LDC Proxy Group

Company	Ticker	[1] 30-day Average Closing Price	[2] Annualized Dividend	[3] Expected Dividend Yield	[4] Mean Projected Growth Rate	[5] Mean Expected Dividend Yield	[6] Second Growth Rate	[7] Mean Expected ROE
Atmos Energy Corporation	ATO	74.70	1.68	2.25%	7.00%	2.33%	6.66%	9.01%
Northwest Natural Gas Company	NWN	60.69	1.87	3.08%	5.00%	3.16%	5.28%	8.40%
South Jersey Industries, Inc.	SJI	29.80	1.06	3.54%	6.33%	3.65%	6.33%	9.98%
Southwest Gas Corporation	SWX	70.95	1.80	2.54%	5.17%	2.60%	5.28%	7.87%
Spire Inc	SR	64.95	1.96	3.02%	6.04%	3.11%	6.04%	9.15%
WGL Holdings, Inc.	WGL	63.30	1.95	3.08%	6.27%	3.18%	6.27%	9.44%
	Mean				5.97%	3.00%	5.98%	8.98%
	Flotation Costs							2.93%
	Mean with Flotation Costs							9.07%

Average	0.059678
SD	0.69%
Average - 1 SD	5.28%
Average + 1 SD	6.66%

Company	Ticker	[8] Year 1 Div.	[9] (1+k)^1	[10] PV of Year 1 Div.	[11] Year 2 Div.	[12] (1+k)^2	[13] PV of Year 2 Div.	[14] Year 3 Div.	[15] (1+k)^3	[16] PV of Year 3 Div.	[17] Year 4 Div.	[18] (1+k)^4	[19] PV of Year 4 Div.	[20] Year 5 Div.	[21] (1+k)^5	[22] PV of Year 5 Div.	[23] Year 6 Div.	[24] Year 5 Stock Price	[25] PV of Year 5 Stock Price	[26] Current Stock Price	[27] CHECK
Atmos Energy Corporation	ATO	1.74	1.09	1.59	1.86	1.19	1.56	1.99	1.30	1.54	2.13	1.41	1.51	2.28	1.54	1.48	2.43	103.19	67.02	74.70	0.00
Northwest Natural Gas Company	NWN	1.92	1.08	1.77	2.01	1.18	1.71	2.11	1.27	1.66	2.22	1.38	1.61	2.33	1.50	1.56	2.45	78.42	52.39	60.69	0.00
South Jersey Industries, Inc.	SJI	1.09	1.10	0.99	1.16	1.21	0.96	1.23	1.33	0.92	1.31	1.46	0.89	1.39	1.61	0.86	1.48	40.51	25.17	29.80	0.00
Southwest Gas Corporation	SWX	1.85	1.08	1.71	1.94	1.16	1.67	2.04	1.26	1.63	2.15	1.35	1.59	2.26	1.46	1.55	2.38	91.73	62.81	70.95	0.00
Spire Inc	SR	2.02	1.09	1.85	2.14	1.19	1.80	2.27	1.30	1.75	2.41	1.42	1.70	2.55	1.55	1.65	2.71	87.08	56.22	64.95	0.00
WGL Holdings, Inc.	WGL	2.01	1.09	1.84	2.14	1.20	1.78	2.27	1.31	1.73	2.41	1.43	1.68	2.56	1.57	1.63	2.72	85.79	54.64	63.30	0.00

Notes:
[1] Source: Bloomberg Professional Service, equals indicated number of trading day average as of September 30, 2016
[2] Source: Bloomberg Professional Service
[16] = [14] / [15]
[17] = [2] x (1 + [4]) ^ (4.0 - 0.5)
[18] = (1 + [7]) ^ (4.0)
[19] = [17] / [18]
[20] = [2] x (1 + [4]) ^ (5.0 - 0.5)
[21] = (1 + [7]) ^ (5.0)
[22] = [20] / [21]
[23] = [20] x (1 + [6])
[24] = [23] / ([7] - [6])
[25] = [24] / [21]
[26] = [10] + [13] + [16] + [19] + [22] + [25]
[27] = [26] - [1]

Two Growth Rate DCF Analysis with Flotation Costs - Average Growth Rate
Combination Proxy Group

Company	Ticker	[1] 30-day Average Closing Price	[2] Annualized Dividend	[3] Expected Dividend Yield	[4] Mean Projected Growth Rate	[5] Mean Expected Dividend Yield	[6] Second Growth Rate	[7] Mean Expected ROE
Ameren Corporation	AEE	49.86	1.70	3.41%	5.77%	3.51%	5.77%	9.27%
Avista Corporation	AVA	41.72	1.37	3.28%	5.10%	3.37%	5.34%	8.68%
CMS Energy Corporation	CMS	42.58	1.24	2.91%	6.62%	3.01%	6.37%	9.40%
DTE Energy Company	DTE	93.94	3.08	3.28%	5.77%	3.37%	5.77%	9.14%
NorthWestern Corporation	NWE	58.45	2.00	3.42%	5.50%	3.51%	5.50%	9.01%
SCANA Corporation	SCG	72.11	2.30	3.19%	5.33%	3.27%	5.34%	8.61%
Vectren Corporation	VVC	49.85	1.60	3.21%	6.43%	3.31%	6.37%	9.69%
Wisconsin Energy Corporation	WEC	60.90	1.98	3.25%	6.31%	3.35%	6.31%	9.66%
	Mean				5.85%	3.34%	5.85%	9.18%
	Flotation Costs							2.93%
	Mean with Flotation Costs							9.28%

Average	5.85%
SD	0.51%
Average - 1 SD	5.34%
Average + 1 SD	6.37%

Company	Ticker	[8] Year 1 Div.	[9] (1+k)^1	[10] PV of Year 1 Div.	[11] Year 2 Div.	[12] (1+k)^2	[13] PV of Year 2 Div.	[14] Year 3 Div.	[15] (1+k)^3	[16] PV of Year 3 Div.	[17] Year 4 Div.	[18] (1+k)^4	[19] PV of Year 4 Div.	[20] Year 5 Div.	[21] (1+k)^5	[22] PV of Year 5 Div.	[23] Year 6 Div.	[24] Year 5 Stock Price	[25] PV of Year 5 Stock Price	[26] Current Stock Price	[27] CHECK
Ameren Corporation	AEE	1.75	1.09	1.60	1.85	1.19	1.55	1.96	1.30	1.50	2.07	1.43	1.45	2.19	1.56	1.40	2.31	66.00	42.36	49.86	0.00
Avista Corporation	AVA	1.40	1.09	1.29	1.48	1.18	1.25	1.55	1.28	1.21	1.63	1.40	1.17	1.71	1.52	1.13	1.81	54.08	35.67	41.72	0.00
CMS Energy Corporation	CMS	1.28	1.09	1.17	1.37	1.20	1.14	1.46	1.31	1.11	1.55	1.43	1.08	1.65	1.57	1.06	1.76	58.02	37.02	42.58	0.00
DTE Energy Company	DTE	3.17	1.09	2.90	3.35	1.19	2.81	3.54	1.30	2.73	3.75	1.42	2.64	3.96	1.55	2.56	4.19	124.36	80.30	93.94	0.00
NorthWestern Corporation	NWE	2.05	1.09	1.88	2.17	1.19	1.82	2.29	1.30	1.76	2.41	1.41	1.71	2.54	1.54	1.65	2.68	76.39	49.61	58.45	0.00
SCANA Corporation	SCG	2.36	1.09	2.17	2.49	1.18	2.11	2.62	1.28	2.04	2.76	1.39	1.98	2.91	1.51	1.92	3.06	93.53	61.88	72.11	0.00
Vectren Corporation	VVC	1.65	1.10	1.50	1.76	1.20	1.46	1.87	1.32	1.42	1.99	1.45	1.37	2.12	1.59	1.33	2.25	67.89	42.76	49.85	0.00
Wisconsin Energy Corporation	WEC	2.04	1.10	1.86	2.17	1.20	1.80	2.31	1.32	1.75	2.45	1.45	1.70	2.61	1.59	1.64	2.77	82.68	52.14	60.90	0.00

[12] = (1 + [7]) ^ (2.0)
[13] = [11] / [12]
[14] = [2] x (1 + [4]) ^ (3.0 - 0.5)
[15] = (1 + [7]) ^ (3.0)
[16] = [14] / [15]
[17] = [2] x (1 + [4]) ^ (4.0 - 0.5)
[18] = (1 + [7]) ^ (4.0)
[19] = [17] / [18]
[20] = [2] x (1 + [4]) ^ (5.0 - 0.5)
[21] = (1 + [7]) ^ (5.0)
[22] = [20] / [21]
[23] = [20] x (1 + [6])
[24] = [23] / ([7] - [6])
[25] = [24] / [21]
[26] = [10] + [13] + [16] + [19] + [22] + [25]
[27] = [26] - [1]

NOT-PUBLIC DOCUMENT
NOT FOR PUBLIC DISCLOSURE

☒ **Not Public Document – Not For Public Disclosure**
☐ **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	Information Request No.	10
Requestor:	Adam J. Heinen		
Date Received:	December 19, 2016		

Question:

Subject: Minnesota Sales

Reference: Page 32

Please provide the following:

A. Any, and all, input data used to construct the sales forecast in Microsoft Excel format with all links and formulae intact;

B. Any, and all, regression outputs including, but not limited to, variables, test-statistics, and forecasting period in Microsoft Excel format with all links and formulae intact;

C. Comparison, by rate class, between this forecast and the Commission-approved rate class forecasts in the last general rate case in Microsoft Excel format; and

D. Declaration of whether the forecast is weather normalized. If so, please fully explain how the Company weather-normalized sales. If not, please fully explain why Xcel did not weather-normalize sales.

If this information has already been provided in written comments or in response to an earlier DOC information request, please identify the specific comment cite(s) or DOC information request number(s).

Response:

A. Please refer to the following attachments to this response. The attachments are submitted in live Excel spreadsheet format.

NOT-PUBLIC DOCUMENT
NOT FOR PUBLIC DISCLOSURE

Attachment Name	Forecast Description
16-0891 DOC-010 Attachment A	Residential Sales
16-0891 DOC-010 Attachment B	Total Commercial Sales
16-0891 DOC-010 Attachment C	Small/Large Commercial Sales Split
16-0891 DOC-010 Attachment D	Demand Sales
16-0891 DOC-010 Attachment E	Small Volume Interruptible Sales
16-0891 DOC-010 Attachment F	Medium Volume Interruptible Sales
16-0891 DOC-010 Attachment G	Large Volume Interruptible Sales
16-0891 DOC-010 Attachment H	Interdepartmental Sales
16-0891 DOC-010 Attachment I	Transportation

Attachments A, F, G and I include Trade Secret information protected by the Minnesota Data Practices Act. The information has economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by other persons and is subject to efforts by the Company to protect the information from public disclosure. Xcel Energy maintains this information as a trade secret pursuant to Minn. Stat. § 13.37, subd. 1(b).

B. Please see Part A to this response

C. Please refer to Attachment J to this response.

D. Yes, the sales forecast is weather normalized. For the classes that are developed using regression models, the regression models identify the historical relationship between actual sales and actual weather. The forecast is developed using the identified relationships and expected normal weather, thereby producing a weather-normalized forecast.

Preparer:	Justin Vicars / Jannell Marks
Title:	Associate Energy Forecasting Analyst / Director
Department:	Sales, Energy and Demand Forecasting
Telephone:	303-571-6253 / 303-571-6254
Date:	December 29, 2016

☐ **Not Public Document – Not For Public Disclosure**
☐ **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	Information Request No.	17
Requestor:	Adam J. Heinen		
Date Received:	December 19, 2016		

Question:

Reference: Attachment C1

Please list for each project the year in which the pipe replaced originally entered service.

If this information has already been provided in written comments or in response to an earlier DOC information request, please identify the specific comment cite(s) or DOC information request number(s).

Response:

Please see Attachment A to this response. Attachment A contains Petition Attachments C1(b), C1(c) and C1(d) modified to include the year the retired main was installed.

Preparer:	Eric Kirkpatrick
Title:	Director – Gas Engineering
Department:	Gas Engineering
Telephone:	303-571-3223
Date:	December 29, 2016

Northern States Power Company

DIMP Replacement Project Detail for 2015

NSP-MN Main & Services DIMP Replacements					Main Footage			Service			Service Cost
Division	Project	WO	Actual from Passport	Year Retired Main was Installed	Estimate	Actual Replaced	Actual Installed from Passport	Estimate	Replaced	Transferred	Actual Cost for Services
St Paul	STP/ARLINGTON, NEVADA, NEBRASKA BTN. WHITE BEAR & FURNESS	11935351	$660,033	1977	12,760	7,100	12,760	230	223	4	221,983
	ROSEVILLE/ COHANSEY ST. PROJECT/ INSTALL 7500' OF 2" PE	12118923	$222,657	1965	7,500	4,530	7,517	74	71	2	70,676
	STP / CLARENCE ST BTN ARLINGTON AVE E & HOYT AVE E / DIMP PR	12096468	$94,089	Unknown	2,600	1,300	1,300	48	46	4	45,790
	Barclay/Dieter	12185039	$206,308	Unknown	3,750	2,675	3,925	60	58	4	$57,736
	STP / IVY AVE E XST: RUTH ST / LOW PRESSURE DIMP PROJECT	12088590	$622,841	2003	16,000	11,350	16,031	218	224	0	$222,979
	STP / 7TH ST W BTN ALTON & RANKIN ST	12217850	$240,863	2012	2,326	4,660	2,326	24	21	4	$20,904
	Idaho / Barclay / Clarence	12227467	$318,811	Unknown	7,350	4,775	7,467	99	93	8	$92,576
	ROSEVILLE/ GALTIER ST/ INSTALL 4600' OF 2" PE MAIN (DIMP)	12122749	$142,754	Unknown	4,400	2,405	4,560	49	48	0	$47,781
White Bear Lake	VADNAIS HEIGHTS-5-STAR MOBILE ESTATES-INSTALL 10,480' 2" PE	12100647	$322,376	1974	10,480	9,225	10,124	190	112	77	$111,489
	LAKE ELMO-CIMARRON MOBILE HOME PARK-SOUTH HALF-RENEW MAIN	12148971	$498,317	1970	15,000	15,234	15,234	250	228	0	$226,960
	LAKE ELMO-CIMARRON MOBILE HOME PARK-NORTH HALF-RENEW MAIN*	12225339	$139,126	1970	16,709	16,064	16,709	252	237	0	$235,919
	WBL/OPH/Area D	12200298	$157,590	1962	5,000	4,520	5,097	12	14	7	$13,936
	Vad Heights - North Star Estates	12226824	$246,291	1972	10,000	7,040	9,485	172	161	8	$160,266
	BAYPORT 5TH ST S INSTALL 3900' OF 2"PE MAIN RENEW 43 SVCS	12093773	$128,522	Unknown	2,900	2,000	3,845	43	16	23	$15,927
	NO ST PAUL / 14th AVE E	11945105	$128,989	Unknown	3,865	2,105	3,999	48	40	6	$39,818
Wyoming	Forest Lake - Carry-over from 2014	12185020	$411,767	168	9,000	10,850	8,741	93	68	28	$67,690
	Forest Lake - 11th Ave & 6th St	12233388	$112,887	Unknown	4,100	3,310	3,310	36	41	6	$40,813
	Forest Lake - 1st Ave / 2nd Ave / 8th St / 7th St / 6th St	12234310	$180,857	Unknown	4,650	3,750	4,642	27	43	9	$42,804
Newport	Cloman Way & Lower 67th St	12262781	$289,384	1971	5,500	3,900	6,322	152	154	0	$153,298
	ST PAUL PARK /2015 DIMP/ DIXON / BLOSSOM	12148969	$58,549	Unknown	2,204	950	2,224	26	26	0	$25,881
	2015 DIMP / ST PAUL PK / DIXON DR	12149144	$115,211	Unknown	2,581	1,600	2,549	29	29	0	$28,868
	2015 DIMP / ST PAUL PK / GARY/ SELBY / DAYTON	12149707	$229,296	Unknown	9,274	5,050	9,274	110	110	0	$109,498
	ST PAUL PARK / 2015 DIMP / PORTLAND AVE / 13TH / 15TH	12101212	$51,323	Unknown	1,800	1,240	1,764	16	11	5	$10,950
	SOUTH ST PAUL / 2015 DIMP / BUTLER / KASSAN	12089427	$74,096	1974	2,224	2,980	2,224	20	15	3	$14,932
	SOUTH ST PAUL / 2015 DIMP BUTLER AVE / BUTLER CT	12101218	$79,734	1974	2,298	1,200	2,298	30	26	6	$25,881
	Denton	12255539	$147,674	1973	4,828	4,220	4,828	75	75	0	$74,658
	Burns Ave	12170859	$244,420	Unknown	6,901	3,900	6,902	85	73	11	$72,667
St Cloud	DLH / DIMP / RIVER'S EDGE PARKING	12188957	$41,844	Unknown	250	256	270	2	0	0	$0
	St Cloud - Lincoln Ave*	12223516	$205,043	Unknown	7,750	5,990	6,273	36	18	11	$17,918
	Watertown	12162124	$312,454	Unknown	10,200	7,030	10,210	95	73	37	$72,667
	Sauk Rapids - 7th St NE (@ 2nd Ave NE)	12227154	$13,639	Unknown	286	250	250	3	3	0	$2,986
Southeast	GOODVIEW-LAKE VILLAGE MOBILE HOME PARK	12157111	$370,276	1974	9,989	6,930	8,455	230	192	0	$191,124
	Northfield Viking Ter	12241776	$399,697	2001	10,550	8,525	7,677	180	180	0	$179,179
	7th St S - Lake City	12205025	$74,600	1980	1,400	-	1,256	6	0	0	$0
	Hallstrom Dr & Burton St - Red Wing	12218584	$448,078	1971	17,000	14,482	14,482	270	136	25	$135,380
	Bluffview - Winona	12231997	$46,329	1971	2,000	1,120	1,626	5	12	3	$11,945
	Bush St & Langsford Ave - Red Wing	12212950	$256,974	1972	5,950	5,100	6,337	85	69	7	$68,685
	Hillsdale - Hidden Valley Mobile Home Park	12162836	$303,914	1976	10,064	8,115	10,699	185	176	0	$175,197
Moorhead	Moorehead 30th Ave & 8th St S	12215066 & 12208317	$25,256	Unknown	975	-		1	0	0	$0
	Moorehead Dale & 5th St S	12215099 & 12210767	$35,169	Unknown	1,608	-	1,599	32	0	0	$0
	Service Materials		$117,369								
		Totals	$8,775,406		254,022	195,731	244,591	3,598	3,122	298	$3,107,764

*Amounts vary from costs presented in Attachment E due to extracting the data from different systems (PowerPlan vs. Passport) and non-recoverable and non-GUIC recoverable costs associated with internal labor.

Northern States Power Company

DIMP Replacement Project Detail for 2016

NSP-MN Main & Services DIMP Replacement Projects 2016								
Area	Work Order Number	Description	Year Retired Main was Installed	Total Design FT.	Tot. Svc	Anticipated Main Cost	Anticipated Service Cost	GL Main Cost (2016 YTD August)
St Paul	12092489	ST PAUL - ARMSTRONG AVE XST: CHATSWORTH ST S	1990	1,350	28	$ 39,474	$ 28,000	$ 8,524
	12328949	ST PAUL - ARMSTRONG AVE	1990	7,506	150	$ 219,475	$ 150,000	$ 30,364
	12381180	ST PAUL - ATLANTIC, DULUTH & LARPENTEUR	1955	8,900	118	$ 260,236	$ 118,000	$ 33,905
	12294860	ROSEVILLE - GLENHILL, WOODLYNN, CLARMAR	1955	7,810	81	$ 228,364	$ 81,000	$ 12,230
	12398688	LAUDERDALE - EUSTIS ST	Unknown	1,100	17	$ 32,164	$ 17,000	$ 43,054
	12380740	ROSEVILLE - WEWERS RD	Unknown	1,400	15	$ 40,936	$ 15,000	$ 51,078
	12404989	ST PAUL - DOWNTOWN - 10TH-MINNESOTA	1957	1,200	5	$ 35,088	$ 5,000	$ 69,353
	12344852	ROSEVILLE - COUNTY RD C, FISK, AVON, GROTTO	1958	23,400	305	$ 684,216	$ 305,000	$ 641,601
	12444470	ST PAUL - DOWN TOWN (Kellogg)	1956	150	-	$ 4,386	$ -	$ -
	12361662	ST PAUL - JUNO CONTRACTOR PORTION	Unknown	4,750	56	$ 138,890	$ 55,882	$ 135,824
	12358730	ST PAUL - JUNO LOCAL PORTION	Unknown	1,260	20	$ 36,842	$ 20,000	$ 46,852
	12364882	ST PAUL - AURORA - LOCAL PORTION	Unknown	960	36	$ 28,070	$ 36,000	$ 37,637
	12369728	ST PAUL - AURORA - CONTRACTOR PORTION	Unknown	3,875	100	$ 113,305	$ 100,000	$ 13,299
	12317526	ST PAUL - BERKELY-STANFORD-WELLESLY	1980	10,440	195	$ 305,266	$ 195,000	$ 15,098
	12294862	ROSEVILLE - SKILLMAN-ELDRIDGE	Unknown	6,700	79	$ 195,908	$ 78,824	$ 18,344
White Bear Lake	12344860	LAKE ELMO - 32ND ST	Unknown	8,600	77	$ 251,464	$ 77,000	$ 303,289
	12293638	LAKE ELMO - LAKE ELMO AVE	Unknown	6,800	51	$ 198,832	$ 51,000	$ 219,505
	12334697	NORTH ST PAUL - 19TH AVE	1956	7,000	85	$ 204,680	$ 85,000	$ 65,399
	12371725	BAYTOWN TWP/ 13606 30TH ST N	Unknown	320	5	$ 9,357	$ 5,000	$ 17,807
	12320156	OAKDALE - GROSPOINT AVE	1960	16,200	178	$ 473,688	$ 178,000	$ 250,615
	12317855	WHITE BEAR LAKE - FLORENCE ST	1976	16,600	109	$ 485,384	$ 109,000	$ 310,730
	12320058	MAPLEWOOD - ROSELAWN AVE	1954	12,900	179	$ 377,196	$ 179,000	$ 361,222
	12320143	OAKDALE - GERSHWIN AVE	1967	9,500	70	$ 277,780	$ 70,000	$ -
	12320392	SHOREVIEW - DEBRA LN	1976	11,200	105	$ 327,488	$ 105,000	$ 231,834
	12317856	SHOREVIEW - NANCY PL	1971	7,600	85	$ 222,224	$ 85,000	$ -
	12275730	OAKDALE - GREENE AVE	Unknown	2,150	22	$ 62,866	$ 22,000	$ -
Wyoming	12334677	FOREST LAKE - 2ND ST SE	1972	10,900	128	$ 318,716	$ 128,235	$ 248,328
Newport	12346387	SOUTH ST PAUL - 3RD AVE S - 6TH ST S	Unknown	1,680	28	$ 49,123	$ 28,000	$ 79,806
	12352620	MENDOTA HTS - 3RD ST-VANDALL-SOMERSET	1968	1,900	22	$ 55,556	$ 22,000	$ 459
	12352631	ST PAUL PARK - 13TH-14TH-CHICAGO	Unknown	8,815	100	$ 257,751	$ 100,000	$ -
	12346491	SOUTH ST PAUL - 2ND AVE S - MARIE AVE	Unknown	7,530	120	$ 220,177	$ 120,000	$ -
	12346357	MENDOTA HTS - HWY 13 - WACHTER AVE	Unknown	911	5	$ 26,638	$ 5,000	$ 5,138
St Cloud	12342575	ST JOSEPH - 1ST AVE NE - CTY RD 75	1966	9,150	79	$ 267,546	$ 79,000	$ 169,520
	12403875	SARTELL - MISSISSIPPI RIVER CROSSING	1973	1,700	-	$ 136,000	$ -	$ -
	12249351	DELANO	Unknown	14,800	127	$ 432,752	$ 127,000	$ 190,478
Southeast	12385504	WINONA - 3RD ST BTW GALE ST-MECHANIC ST	1974	8,100	127	$ 236,844	$ 127,000	$ 77,222
	12354151	NORTHFIELD - FLORELLAS CT	1968	1,550	22	$ 45,322	$ 22,000	$ -
	12328936	FARIBAULT - 8TH ST SW	Unknown	5,320	48	$ 155,557	$ 48,000	$ 59,368
	12345274	FARIBAULT - 7TH ST NW	1980	4,900	43	$ 143,276	$ 43,000	$ -
	12350531	FARIBAULT - 8TH ST SW, BOTSFORD, CARLTON	Unknown	3,000	49	$ 87,720	$ 49,000	$ -
Moorhead	12359542	MOORHEAD - REGAL ESTATES	Unknown	10,500	210	$ 307,020	$ 210,000	$ 87,753
2016 DIMP-related Main Replacement Total				270,427	3,279	$ 7,993,577	$ 3,278,941	$ 3,835,636

*Project detail amounts vary from costs presented in Attachment C, due to extracting the data from different systems (PowerPlan vs. Passport) and non-recoverable costs associated with internal labor.

Northern States Power Company

DIMP Replacement Project Detail for 2017

NSP-MN Main & Services DIMP Replacement Projects 2017						
Area	Work Order Number	Description	Year Retired Main was Installed	Total Design FT.	Tot. Svc	Anticipated Cost
St Paul	12294045	ROSEVILLE - FERNWOOD ST	1955	3,760	44	$109,942
	12315892	ST PAUL - CASE AVE BTN EDGERTON-EARL	1979	11,300	177	$330,412
	12328310	ST PAUL - HAGUE/SELBY	1978	6,745	128	$197,224
	12326608	ST PAUL - EDMOND	Unknown	5,290	113	$154,680
	N/A	ST PAUL - ST PETER, FORD 4TH	1963	4,200	62	$122,808
	12320752	ST PAUL - ETNA-BIRMINGHAM-WINCHELL	1962	9,600	141	$280,704
White Bear Lake	12317581	ARDEN HILLS - ARDEN VIEW DR	Unknown	2,300	34	$67,252
	12320389	ARDEN HILLS - GLENPAUL AVE	Unknown	4,700	58	$137,428
	12319969	MAHTOMEDI - GRIFFIN AVE	1968	3,200	39	$93,568
	12092590	BAYPORT - 7TH ST	1964	1,000	11	$29,240
Wyoming	12320014	FOREST LAKE - 11TH AVE SW (LAKE ST)	Unknown	2,100	25	$61,404
	12320051	FOREST LAKE - 208TH-209TH ST	1969	4,000	47	$116,960
	12320027	FOREST LAKE - IVERSON AVE	1967	3,700	53	$108,188
	N/A	FOREST LAKE - HEATH AVE	1968	3,600	34	$105,264
Newport	12352434	COTTAGE GROVE - IRONWOOD	1971	3,338	100	$97,603
	12438126	ST PAUL - BURNS-RUTH	Unknown	11,715	147	$342,547
	DE 522036	COTTAGE GROVE - HYDE	1961	3,710	41	$108,480
	DE 521888	COTTAGE GROVE - PT DOUGLAS RD, IDEAL AVE	1961	4,735	56	$138,451
	DE 521609	COTTAGE GROVE - IDEAL-85TH ST	1962	4,160	36	$121,638
	DE 521021	MENDOTA HTS - BACHELOR-SUTTON-MARIE	1973	10,570	77	$309,067
	DE 526906	INVER GROVE HTS - DAWN-UPPER 75TH-77TH	1971	5,160	89	$150,878
	DE 519457	INVER GROVE HTS - CONROY CT	1972	5,400	142	$157,896
St Cloud	N/A	ST CLOUD - 16TH AVE - 3RD ST N	1972	4,100	26	$119,884
	12412846	ST CLOUD - 44TH AVE N, APPOLLO BY VA	1972	2,500	10	$73,100
Southeast	DE 525652	WINONA - 3RD ST BTW WINONA ST-LIBERTY ST	1968	8,500	154	$248,540
	12320940	NORTHFIELD - WOODLEY ST E	1977	500	13	$14,620
	12344771	NORTHFIELD - ARCHIBALD ST/ASTER	1981	3,500	55	$102,340
	12356426	LAKE CITY - LAKEWOOD AVE	1972	4,250	79	$124,270
	12360394	RED WING - SPRUCE/SOUTHWOOD	Unknown	6,000	86	$175,440
	12356414	WINONA - 9TH/52ND	1977	3,500	42	$102,340
	N/A	NORTHFIELD - EDWARDS LN	1968	1,660	42	$48,538
	DE 525650	RED WING - BUSH ST - PLUM ST	1983	3,250	76	$95,030
	N/A	RED WING - WRIGHT/FINRUD	1975	10,400	130	$304,096
Moorhead	12410474	MOORHEAD-MOBILE MANOR-1224 15TH AVE. N	1972	1,260	38	$36,842
	12422040	DILWORTH - 1ST AVE SE	1972	5,000	48	$146,200
2017 Designed DIMP-related Main Replacement Total				168,703	2,453	$4,932,876

*Remaining projects are in-process of development and design; this work will take place the last quarter of 2016 and the first two quarters of 2017.

* Actual costs are through December 31, 2015. Project detail amounts vary from costs presented in Attachment C, due to extracting the data from different systems (PowerPlan vs. Passport) and non-recoverable costs associated with internal labor.

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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	Information Request No.	17
Requestor:	Adam J. Heinen		
Date Received:	December 19, 2016		**Revised**

Question:

Reference: Attachment C1

Please list for each project the year in which the pipe replaced originally entered service.

If this information has already been provided in written comments or in response to an earlier DOC information request, please identify the specific comment cite(s) or DOC information request number(s).

Response:

Please see Attachment A to this response. Attachment A contains Petition Attachments C1(b), C1(c) and C1(d) modified to include the year the retired main was installed.

Revision:

After discussions with the Department of Commerce, we reviewed this response and discovered erroneous data. Seventeen of the "Year Retired Main was installed" dates (highlighted in green in Attachment A to this response) have been updated or revised in this response. Attachment A Revised is provided in live Excel spreadsheet format. The updated installed dates were obtained by going back to the original as-built records.

Preparer:	Eric Kirkpatrick	
Title:	Director – Gas Engineering	
Department:	Gas Engineering	
Telephone:	303-571-3223	
Date:	December 29, 2016	**Revised: February 24, 2017**

Northern States Power Company | Docket No. G002/M-16-
Gas Utility Infrastructure Cost Rider - 2017 Factors
DIMP Replacement Project Detail for 2015 | Attachment C1(b)

NSP-MN Main & Services DIMP Replacements					Main Footage			Service			Service Cost
Division	Project	WO	Actual from Passport	Year Retired Main was Installed	Estimate	Actual Replaced	Actual Installed from Passport	Estimate	Replaced	Transferred	Actual Cost for Services
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	ROSEVILLE/ COHANSEY ST. PROJECT/ INSTALL 7500' OF 2" PE	12118923	$222,657	1965	7,500	4,530	7,517	74	71	2	70,676
	STP / CLARENCE ST BTN ARLINGTON AVE E & HOYT AVE E / DIMP PR	12096468	$94,089	1967	2,600	1,300	1,300	48	46	4	45,790
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	STP / 7TH ST W BTN ALTON & RANKIN ST	12217850	$240,863	1972	2,326	4,660	2,326	24	21	4	$20,904
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	ROSEVILLE/ GALTIER ST/ INSTALL 4600' OF 2" PE MAIN (DIMP)	12122749	$142,754	Unknown	4,400	2,405	4,560	49	48	0	$47,781
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	2015 DIMP / ST PAUL PK / DIXON DR	12149144	$115,211	Unknown	2,581	1,600	2,549	29	29	0	$28,868
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	Denton	12255539	$147,674	1973	4,828	4,220	4,828	75	75	0	$74,658
	Burns Ave	12170859	$244,420	Unknown	6,901	3,900	6,902	85	73	11	$72,667
St Cloud	DLH / DIMP / RIVER'S EDGE PARKING	12188957	$41,844	Unknown	250	256	270	2	0	0	$0
	St Cloud - Lincoln Ave*	12223516	$205,043	Unknown	7,750	5,990	6,273	36	18	11	$17,918
	Watertown	12162124	$312,454	Unknown	10,200	7,030	10,210	95	73	37	$72,667
	Sauk Rapids - 7th St NE (@ 2nd Ave NE)	12227154	$13,639	Unknown	286	250	250	3	3	0	$2,986
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	Northfield Viking Ter	12241776	$399,697	1970	10,550	8,525	7,677	180	180	0	$179,179
	7th St S - Lake City	12205025	$74,600	1971	1,400	-	1,256	6	0	0	$0
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	Bluffview - Winona	12231997	$46,329	1971	2,000	1,120	1,626	5	12	3	$11,945
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	Hillsdale - Hidden Valley Mobile Home Park	12162836	$303,914	1976	10,064	8,115	10,699	185	176	0	$175,197
Moorhead	Moorehead 30th Ave & 8th St S	12215066 & 12208317	$25,256	Unknown	975	-		1	0	0	$0
	Moorehead Dale & 5th St S	12215099 & 12210767	$35,169	Unknown	1,608	-	1,599	32	0	0	$0
	Service Materials		$117,369								
		Totals	$8,775,406		254,022	195,731	244,591	3,598	3,122	298	$3,107,764

*Amounts vary from costs presented in Attachment E due to extracting the data from different systems (PowerPlan vs. Passport) and non-recoverable and non-GUIC recoverable costs associated with internal labor.

Northern States Power Company | Docket No. G002/M-16-___
Gas Utility Infrastructure Cost Rider - 2017 Factors
DIMP Replacement Project Detail for 2016 | Attachment C1(c)

NSP-MN Main & Services DIMP Replacement Projects 2016

Area	Work Order Number	Description	Year Retired Main was Installed	Total Design FT.	Tot. Svc	Anticipated Main Cost	Anticipated Service Cost	GL Main Cost (2016 YTD August)
	12092489	ST PAUL - ARMSTRONG AVE XST: CHATSWORTH ST S	1990	1,350	28	$ 39,474	$ 28,000	$ 8,524
	12328949	ST PAUL - ARMSTRONG AVE	1990	7,506	150	$ 219,475	$ 150,000	$ 30,364
	12381180	ST PAUL - ATLANTIC, DULUTH & LARPENTEUR	1955	8,900	118	$ 260,236	$ 118,000	$ 33,905
	12294860	ROSEVILLE - GLENHILL, WOODLYNN, CLARMAR	1955	7,810	81	$ 228,364	$ 81,000	$ 12,230
	12398688	LAUDERDALE - EUSTIS ST	Unknown	1,100	17	$ 32,164	$ 17,000	$ 43,054
	12380740	ROSEVILLE - WEWERS RD	Unknown	1,400	15	$ 40,936	$ 15,000	$ 51,078
	12404989	ST PAUL - DOWNTOWN - 10TH-MINNESOTA	1957	1,200	5	$ 35,088	$ 5,000	$ 69,353
St Paul	12344852	ROSEVILLE - COUNTY RD C, FISK, AVON, GROTTO	1958	23,400	305	$ 684,216	$ 305,000	$ 641,601
	12444470	ST PAUL - DOWN TOWN (Kellogg)	1956	150	-	$ 4,386	$ -	$ -
	12361662	ST PAUL - JUNO CONTRACTOR PORTION	1980	4,750	56	$ 138,890	$ 55,882	$ 135,824
	12358730	ST PAUL - JUNO LOCAL PORTION	1980	1,260	20	$ 36,842	$ 20,000	$ 46,852
	12364882	ST PAUL - AURORA - LOCAL PORTION	1980	960	36	$ 28,070	$ 36,000	$ 37,637
	12369728	ST PAUL - AURORA - CONTRACTOR PORTION	1980	3,875	100	$ 113,305	$ 100,000	$ 13,299
	12317526	ST PAUL - BERKELY-STANFORD-WELLESLY	1980	10,440	195	$ 305,266	$ 195,000	$ 15,098
	12294862	ROSEVILLE - SKILLMAN-ELDRIDGE	1963	6,700	79	$ 195,908	$ 78,824	$ 18,344
	12344860	LAKE ELMO - 32ND ST	Unknown	8,600	77	$ 251,464	$ 77,000	$ 303,289
	12293638	LAKE ELMO - LAKE ELMO AVE	Unknown	6,800	51	$ 198,832	$ 51,000	$ 219,505
	12334697	NORTH ST PAUL - 19TH AVE	1956	7,000	85	$ 204,680	$ 85,000	$ 65,399
	12371725	BAYTOWN TWP/ 13606 30TH ST N	Unknown	320	5	$ 9,357	$ 5,000	$ 17,807
	12320156	OAKDALE - GROSPOINT AVE	1960	16,200	178	$ 473,688	$ 178,000	$ 250,615
White Bear Lake	12317855	WHITE BEAR LAKE - FLORENCE ST	1976	16,600	109	$ 485,384	$ 109,000	$ 310,730
	12320058	MAPLEWOOD - ROSELAWN AVE	1954	12,900	179	$ 377,196	$ 179,000	$ 361,222
	12320143	OAKDALE - GERSHWIN AVE	1967	9,500	70	$ 277,780	$ 70,000	$ -
	12320392	SHOREVIEW - DEBRA LN	1976	11,200	105	$ 327,488	$ 105,000	$ 231,834
	12317856	SHOREVIEW - NANCY PL	1971	7,600	85	$ 222,224	$ 85,000	$ -
	12275730	OAKDALE - GREENE AVE	Unknown	2,150	22	$ 62,866	$ 22,000	$ -
Wyoming	12334677	FOREST LAKE - 2ND ST SE	1972	10,900	128	$ 318,716	$ 128,235	$ 248,328
	12346387	SOUTH ST PAUL - 3RD AVE S - 6TH ST S	Unknown	1,680	28	$ 49,123	$ 28,000	$ 79,806
	12352620	MENDOTA HTS - 3RD ST-VANDALL-SOMERSET	1968	1,900	22	$ 55,556	$ 22,000	$ 459
Newport	12352631	ST PAUL PARK - 13TH-14TH-CHICAGO	Unknown	8,815	100	$ 257,751	$ 100,000	$ -
	12346491	SOUTH ST PAUL - 2ND AVE S - MARIE AVE	Unknown	7,530	120	$ 220,177	$ 120,000	$ -
	12346357	MENDOTA HTS - HWY 13 - WACHTER AVE	Unknown	911	5	$ 26,638	$ 5,000	$ 5,138
	12342575	ST JOSEPH - 1ST AVE NE - CTY RD 75	1966	9,150	79	$ 267,546	$ 79,000	$ 169,520
St Cloud	12403875	SARTELL - MISSISSIPPI RIVER CROSSING	1973	1,700	-	$ 136,000	$ -	$ -
	12249351	DELANO	Unknown	14,800	127	$ 432,752	$ 127,000	$ 190,478
	12385504	WINONA - 3RD ST BTW GALE ST-MECHANIC ST	1974	8,100	127	$ 236,844	$ 127,000	$ 77,222
Southeast	12354151	NORTHFIELD - FLORELLAS CT	1968	1,550	22	$ 45,322	$ 22,000	$ -
	12328936	FARIBAULT - 8TH ST SW	Unknown	5,320	48	$ 155,557	$ 48,000	$ 59,368
	12345274	FARIBAULT - 7TH ST NW	1980	4,900	43	$ 143,276	$ 43,000	$ -
	12350531	FARIBAULT - 8TH ST SW, BOTSFORD, CARLTON	Unknown	3,000	49	$ 87,720	$ 49,000	$ -
Moorhead	12359542	MOORHEAD - REGAL ESTATES	Unknown	10,500	210	$ 307,020	$ 210,000	$ 87,753
2016 DIMP-related Main Replacement Total				**270,427**	**3,279**	**$ 7,993,577**	**$ 3,278,941**	**$ 3,835,636**

*Project detail amounts vary from costs presented in Attachment C, due to extracting the data from different systems (PowerPlan vs. Passport) and non-recoverable costs associated with internal labor.

Northern States Power Company

Docket No. G002/M-16-___
Gas Utility Infrastructure Cost Rider - 2017 Factors

DIMP Replacement Project Detail for 2017

Attachment C1(d)

NSP-MN Main & Services DIMP Replacement Projects 2017

Area	Work Order Number	Description	Year Retired Main was Installed	Total Design FT.	Tot. Svc	Anticipated Cost
St Paul	12294045	ROSEVILLE - FERNWOOD ST	1955	3,760	44	$109,942
	12315892	ST PAUL - CASE AVE BTN EDGERTON-EARL	1979	11,300	177	$330,412
	12328310	ST PAUL - HAGUE/SELBY	1978	6,745	128	$197,224
	12326608	ST PAUL - EDMOND	Unknown	5,290	113	$154,680
	N/A	ST PAUL - ST PETER, FORD 4TH	1963	4,200	62	$122,808
	12320752	ST PAUL - ETNA-BIRMINGHAM-WINCHELL	1962	9,600	141	$280,704
White Bear Lake	12317581	ARDEN HILLS - ARDEN VIEW DR	Unknown	2,300	34	$67,252
	12320389	ARDEN HILLS - GLENPAUL AVE	1955	4,700	58	$137,428
	12319969	MAHTOMEDI - GRIFFIN AVE	1968	3,200	39	$93,568
	12092590	BAYPORT - 7TH ST	1964	1,000	11	$29,240
Wyoming	12320014	FOREST LAKE - 11TH AVE SW (LAKE ST)	Unknown	2,100	25	$61,404
	12320051	FOREST LAKE - 208TH-209TH ST	1969	4,000	47	$116,960
	12320027	FOREST LAKE - IVERSON AVE	1967	3,700	53	$108,188
	N/A	FOREST LAKE - HEATH AVE	1968	3,600	34	$105,264
Newport	12352434	COTTAGE GROVE - IRONWOOD	1971	3,338	100	$97,603
	12438126	ST PAUL - BURNS-RUTH	1955	11,715	147	$342,547
	DE 522036	COTTAGE GROVE - HYDE	1961	3,710	41	$108,480
	DE 521888	COTTAGE GROVE - PT DOUGLAS RD, IDEAL AVE	1961	4,735	56	$138,451
	DE 521609	COTTAGE GROVE - IDEAL-85TH ST	1962	4,160	36	$121,638
	DE 521021	MENDOTA HTS - BACHELOR-SUTTON-MARIE	1973	10,570	77	$309,067
	DE 526906	INVER GROVE HTS - DAWN-UPPER 75TH-77TH	1971	5,160	89	$150,878
	DE 519457	INVER GROVE HTS - CONROY CT	1972	5,400	142	$157,896
St Cloud	N/A	ST CLOUD - 16TH AVE - 3RD ST N	1972	4,100	26	$119,884
	12412846	ST CLOUD - 44TH AVE N, APPOLLO BY VA	1972	2,500	10	$73,100
Southeast	DE 525652	WINONA - 3RD ST BTW WINONA ST-LIBERTY ST	1968	8,500	154	$248,540
	12320940	NORTHFIELD - WOODLEY ST E	1977	500	13	$14,620
	12344771	NORTHFIELD - ARCHIBALD ST/ASTER	1981	3,500	55	$102,340
	12356426	LAKE CITY - LAKEWOOD AVE	1972	4,250	79	$124,270
	12360394	RED WING - SPRUCE/SOUTHWOOD	Unknown	6,000	86	$175,440
	12356414	WINONA - 9TH/52ND	1977	3,500	42	$102,340
	N/A	NORTHFIELD - EDWARDS LN	1968	1,660	42	$48,538
	DE 525650	RED WING - BUSH ST - PLUM ST	1983	3,250	76	$95,030
	N/A	RED WING - WRIGHT/FINRUD	1975	10,400	130	$304,096
Moorhead	12410474	MOORHEAD-MOBILE MANOR-1224 15TH AVE. N	1972	1,260	38	$36,842
	12422040	DILWORTH - 1ST AVE SE	1972	5,000	48	$146,200
2017 Designed DIMP-related Main Replacement Total				**168,703**	**2,453**	**$4,932,876**

*Remaining projects are in-process of development and design; this work will take place the last quarter of 2016 and the first two quarters of 2017.

* Actual costs are through December 31, 2015. Project detail amounts vary from costs presented in Attachment C, due to extracting the data from different systems (PowerPlan vs. Passport) and non-recoverable costs associated with internal labor.

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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	Information Request No.	6
Requestor:	Adam J. Heinen		
Date Received:	December 19, 2016		

Question:

Reference: Page 24

In the above reference, the Company stated the following:

Only the camera inspection aspect of the program is outsourced. At present, the Company has neither the internal expertise nor the equipment available to perform this specialized aspect of the program. By outsourcing the inspections, the Company has spared ratepayers the cost of expensive, specialized equipment, and ensured that those with the expertise are conducting the investigations.

Given the length and breadth of these GUIC projects, has the Company conducted a cost/benefit analysis substantiating Xcel's decision to outsource this work. If so, please provide these analyses. If not, please fully explain why Xcel has not conducted these type of analyses and also why recovery of these costs would be reasonable if the Company has not been able to justify them through a cost/benefit analysis.

If this information has already been provided in written comments or in response to an earlier DOC information request, please identify the specific comment cite(s) or DOC information request number(s).

Response:

The Company believes that the recovery of costs associated with this work is reasonable because it aligns with the eligibility requirements set forth in the Minnesota Statute § 216B.1635, supporting public safety for our customers. The Commission found (page 10 of Xcel Energy's 2017 GUIC Petition, Docket No. G002/M-16-891) that Company investments meet the statutory requirements for rider recovery as gas utility infrastructure costs.

The Company has not conducted a cost/benefit analysis related to the decision to outsource this work. Inspecting sewer lines for potential conflicts with natural gas lines is a unique activity that differs from normal activities associated with the installation, operations and maintenance of a gas system. Because of this uniqueness, the Company has not determined that investing in the ownership of the specialized equipment or training necessary to perform the work as practical.

As with other GUIC programs of work, the Company has established governance of the sewer mitigation project including monthly tracking of progress, expenditures, findings and strategy. This governance team meets on a monthly basis, and provides an annual update to the Minnesota Office of Pipeline Safety of progress and findings.

Preparer:	Katie Hellfritz
Title:	Senior Director
Department:	Gas Governance
Telephone:	303-571-3162
Date:	December 29, 2016

NOT-PUBLIC DOCUMENT
NOT FOR PUBLIC DISCLOSURE

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☐ **Public Document**

Xcel Energy			
Docket No.:	G002/M-16-891		
Response To:	Department of Commerce	Information Request No.	10
Requestor:	Adam J. Heinen		
Date Received:	December 19, 2016		

Question:

Subject: Minnesota Sales

Reference: Page 32

Please provide the following:

A. Any, and all, input data used to construct the sales forecast in Microsoft Excel format with all links and formulae intact;

B. Any, and all, regression outputs including, but not limited to, variables, test-statistics, and forecasting period in Microsoft Excel format with all links and formulae intact;

C. Comparison, by rate class, between this forecast and the Commission-approved rate class forecasts in the last general rate case in Microsoft Excel format; and

D. Declaration of whether the forecast is weather normalized. If so, please fully explain how the Company weather-normalized sales. If not, please fully explain why Xcel did not weather-normalize sales.

If this information has already been provided in written comments or in response to an earlier DOC information request, please identify the specific comment cite(s) or DOC information request number(s).

Response:

A. Please refer to the following attachments to this response. The attachments are submitted in live Excel spreadsheet format.

NOT-PUBLIC DOCUMENT
NOT FOR PUBLIC DISCLOSURE

Attachment Name	Forecast Description
16-0891 DOC-010 Attachment A	Residential Sales
16-0891 DOC-010 Attachment B	Total Commercial Sales
16-0891 DOC-010 Attachment C	Small/Large Commercial Sales Split
16-0891 DOC-010 Attachment D	Demand Sales
16-0891 DOC-010 Attachment E	Small Volume Interruptible Sales
16-0891 DOC-010 Attachment F	Medium Volume Interruptible Sales
16-0891 DOC-010 Attachment G	Large Volume Interruptible Sales
16-0891 DOC-010 Attachment H	Interdepartmental Sales
16-0891 DOC-010 Attachment I	Transportation

Attachments A, F, G and I include Trade Secret information protected by the Minnesota Data Practices Act. The information has economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by other persons and is subject to efforts by the Company to protect the information from public disclosure. Xcel Energy maintains this information as a trade secret pursuant to Minn. Stat. § 13.37, subd. 1(b).

B. Please see Part A to this response

C. Please refer to Attachment J to this response.

D. Yes, the sales forecast is weather normalized. For the classes that are developed using regression models, the regression models identify the historical relationship between actual sales and actual weather. The forecast is developed using the identified relationships and expected normal weather, thereby producing a weather-normalized forecast.

Preparer: Justin Vicars / Jannell Marks
Title: Associate Energy Forecasting Analyst / Director
Department: Sales, Energy and Demand Forecasting
Telephone: 303-571-6253 / 303-571-6254
Date: December 29, 2016

☐ **Not Public Document – Not For Public Disclosure**
☐ **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	Information Request No.	17
Requestor:	Adam J. Heinen		
Date Received:	December 19, 2016		

Question:

Reference: Attachment C1

Please list for each project the year in which the pipe replaced originally entered service.

If this information has already been provided in written comments or in response to an earlier DOC information request, please identify the specific comment cite(s) or DOC information request number(s).

Response:

Please see Attachment A to this response. Attachment A contains Petition Attachments C1(b), C1(c) and C1(d) modified to include the year the retired main was installed.

Preparer:	Eric Kirkpatrick
Title:	Director – Gas Engineering
Department:	Gas Engineering
Telephone:	303-571-3223
Date:	December 29, 2016

Northern States Power Company

DIMP Replacement Project Detail for 2015

Docket No. G002/M-16-___
Gas Utility Infrastructure Cost Rider - 2017 Factors
Attachment C1(b)

NSP-MN Main & Services DIMP Replacements					Main Footage			Service			Service Cost
Division	Project	WO	Actual from Passport	Year Retired Main was Installed	Estimate	Actual Replaced	Actual Installed from Passport	Estimate	Replaced	Transferred	Actual Cost for Services
St Paul	STP/ARLINGTON, NEVADA, NEBRASKA BTN. WHITE BEAR & FURNESS	11935351	$660,033	1977	12,760	7,100	12,760	230	223	4	221,983
	ROSEVILLE/ COHANSEY ST. PROJECT/ INSTALL 7500' OF 2" PE	12118923	$222,657	1965	7,500	4,530	7,517	74	71	2	70,676
	STP / CLARENCE ST BTN ARLINGTON AVE E & HOYT AVE E / DIMP PR	12096468	$94,089	Unknown	2,600	1,300	1,300	48	46	4	45,790
	Barclay/Dieter	12185039	$206,308	Unknown	3,750	2,675	3,925	60	58	4	$57,736
	STP / IVY AVE E XST: RUTH ST / LOW PRESSURE DIMP PROJECT	12088590	$622,841	2003	16,000	11,350	16,031	218	224	0	$222,979
	STP / 7TH ST W BTN ALTON & RANKIN ST	12217850	$240,863	2012	2,326	4,660	2,326	24	21	4	$20,904
	Idaho / Barclay / Clarence	12227467	$318,811	Unknown	7,350	4,775	7,467	99	93	8	$92,576
	ROSEVILLE/ GALTIER ST/ INSTALL 4600' OF 2" PE MAIN (DIMP)	12122749	$142,754	Unknown	4,400	2,405	4,560	49	48	0	$47,781
White Bear Lake	VADNAIS HEIGHTS-5-STAR MOBILE ESTATES-INSTALL 10,480' 2" PE	12100647	$322,376	1974	10,480	9,225	10,124	190	112	77	$111,489
	LAKE ELMO-CIMARRON MOBILE HOME PARK-SOUTH HALF-RENEW MAIN	12148971	$498,317	1970	15,000	15,234	15,234	250	228	0	$226,960
	LAKE ELMO-CIMARRON MOBILE HOME PARK-NORTH HALF-RENEW MAIN*	12225339	$139,126	1970	16,709	16,064	16,709	252	237	0	$235,919
	WBL/OPH/Area D	12200298	$157,590	1962	5,000	4,520	5,097	12	14	7	$13,936
	Vad Heights - North Star Estates	12226824	$246,291	1972	10,000	7,040	9,485	172	161	8	$160,266
	BAYPORT 5TH ST S INSTALL 3900' OF 2"PE MAIN RENEW 43 SVCS	12093773	$128,522	Unknown	2,900	2,000	3,845	43	16	23	$15,927
	NO ST PAUL / 14th AVE E	11945105	$128,989	Unknown	3,865	2,105	3,999	48	40	6	$39,818
Wyoming	Forest Lake - Carry-over from 2014	12185020	$411,767	168	9,000	10,850	8,741	93	68	28	$67,690
	Forest Lake - 11th Ave & 6th St	12233388	$112,887	Unknown	4,100	3,310	3,310	36	41	6	$40,813
	Forest Lake - 1st Ave / 2nd Ave / 8th St / 7th St / 6th St	12234310	$180,857	Unknown	4,650	3,750	4,642	27	43	9	$42,804
Newport	Cloman Way & Lower 67th St	12262781	$289,384	1971	5,500	3,900	6,322	152	154	0	$153,298
	ST PAUL PARK /2015 DIMP/ DIXON / BLOSSOM	12148969	$58,549	Unknown	2,204	950	2,224	26	26	0	$25,881
	2015 DIMP / ST PAUL PK / DIXON DR	12149144	$115,211	Unknown	2,581	1,600	2,549	29	29	0	$28,868
	2015 DIMP / ST PAUL PK / GARY/ SELBY / DAYTON	12149707	$229,296	Unknown	9,274	5,050	9,274	110	110	0	$109,498
	ST PAUL PARK / 2015 DIMP / PORTLAND AVE / 13TH / 15TH	12101212	$51,323	Unknown	1,800	1,240	1,764	16	11	5	$10,950
	SOUTH ST PAUL / 2015 DIMP / BUTLER / KASSAN	12089427	$74,096	1974	2,224	2,980	2,224	20	15	3	$14,932
	SOUTH ST PAUL / 2015 DIMP BUTLER AVE / BUTLER CT	12101218	$79,734	1974	2,298	1,200	2,298	30	26	6	$25,881
	Denton	12255539	$147,674	1973	4,828	4,220	4,828	75	75	0	$74,658
	Burns Ave	12170859	$244,420	Unknown	6,901	3,900	6,902	85	73	11	$72,667
St Cloud	DLH / DIMP / RIVER'S EDGE PARKING	12188957	$41,844	Unknown	250	256	270	2	0	0	$0
	St Cloud - Lincoln Ave*	12223516	$205,043	Unknown	7,750	5,990	6,273	36	18	11	$17,918
	Watertown	12162124	$312,454	Unknown	10,200	7,030	10,210	95	73	37	$72,667
	Sauk Rapids - 7th St NE (@ 2nd Ave NE)	12227154	$13,639	Unknown	286	250	250	3	3	0	$2,986
Southeast	GOODVIEW-LAKE VILLAGE MOBILE HOME PARK	12157111	$370,276	1974	9,989	6,930	8,455	230	192	0	$191,124
	Northfield Viking Ter	12241776	$399,697	2001	10,550	8,525	7,677	180	180	0	$179,179
	7th St S - Lake City	12205025	$74,600	1980	1,400	-	1,256	6	0	0	$0
	Hallstrom Dr & Burton St - Red Wing	12218584	$448,078	1971	17,000	14,482	14,482	270	136	25	$135,380
	Bluffview - Winona	12231997	$46,329	1971	2,000	1,120	1,626	5	12	3	$11,945
	Bush St & Langsford Ave - Red Wing	12212950	$256,974	1972	5,950	5,100	6,337	85	69	7	$68,685
	Hillsdale - Hidden Valley Mobile Home Park	12162836	$303,914	1976	10,064	8,115	10,699	185	176	0	$175,197
Moorhead	Moorehead 30th Ave & 8th St S	12215066 & 12208317	$25,256	Unknown	975	-		1	0	0	$0
	Moorehead Dale & 5th St S	12215099 & 12210767	$35,169	Unknown	1,608	-	1,599	32	0	0	$0
	Service Materials		$117,369								
		Totals	$8,775,406		254,022	195,731	244,591	3,598	3,122	298	$3,107,764

*Amounts vary from costs presented in Attachment E due to extracting the data from different systems (PowerPlan vs. Passport) and non-recoverable and non-GUIC recoverable costs associated with internal labor.

Northern States Power Company

DIMP Replacement Project Detail for 2016

Docket No. G002/M-16-____
Gas Utility Infrastructure Cost Rider - 2017 Factors
Attachment C1(c)

NSP-MN Main & Services DIMP Replacement Projects 2016

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	12398688	LAUDERDALE - EUSTIS ST	Unknown	1,100	17	$ 32,164	$ 17,000	$ 43,054
	12380740	ROSEVILLE - WEWERS RD	Unknown	1,400	15	$ 40,936	$ 15,000	$ 51,078
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	12444470	ST PAUL - DOWN TOWN (Kellogg)	1956	150	-	$ 4,386	$ -	$ -
	12361662	ST PAUL - JUNO CONTRACTOR PORTION	Unknown	4,750	56	$ 138,890	$ 55,882	$ 135,824
	12358730	ST PAUL - JUNO LOCAL PORTION	Unknown	1,260	20	$ 36,842	$ 20,000	$ 46,852
	12364882	ST PAUL - AURORA - LOCAL PORTION	Unknown	960	36	$ 28,070	$ 36,000	$ 37,637
	12369728	ST PAUL - AURORA - CONTRACTOR PORTION	Unknown	3,875	100	$ 113,305	$ 100,000	$ 13,299
	12317526	ST PAUL - BERKELY-STANFORD-WELLESLY	1980	10,440	195	$ 305,266	$ 195,000	$ 15,098
	12294862	ROSEVILLE - SKILLMAN-ELDRIDGE	Unknown	6,700	79	$ 195,908	$ 78,824	$ 18,344
White Bear Lake	12344860	LAKE ELMO - 32ND ST	Unknown	8,600	77	$ 251,464	$ 77,000	$ 303,289
	12293638	LAKE ELMO - LAKE ELMO AVE	Unknown	6,800	51	$ 198,832	$ 51,000	$ 219,505
	12334697	NORTH ST PAUL - 19TH AVE	1956	7,000	85	$ 204,680	$ 85,000	$ 65,399
	12371725	BAYTOWN TWP/ 13606 30TH ST N	Unknown	320	5	$ 9,357	$ 5,000	$ 17,807
	12320156	OAKDALE - GROSPOINT AVE	1960	16,200	178	$ 473,688	$ 178,000	$ 250,615
	12317855	WHITE BEAR LAKE - FLORENCE ST	1976	16,600	109	$ 485,384	$ 109,000	$ 310,730
	12320058	MAPLEWOOD - ROSELAWN AVE	1954	12,900	179	$ 377,196	$ 179,000	$ 361,222
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	12317856	SHOREVIEW - NANCY PL	1971	7,600	85	$ 222,224	$ 85,000	$ -
	12275730	OAKDALE - GREENE AVE	Unknown	2,150	22	$ 62,866	$ 22,000	$ -
Wyoming	12334677	FOREST LAKE - 2ND ST SE	1972	10,900	128	$ 318,716	$ 128,235	$ 248,328
Newport	12346387	SOUTH ST PAUL - 3RD AVE S - 6TH ST S	Unknown	1,680	28	$ 49,123	$ 28,000	$ 79,806
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	12352631	ST PAUL PARK - 13TH-14TH-CHICAGO	Unknown	8,815	100	$ 257,751	$ 100,000	$ -
	12346491	SOUTH ST PAUL - 2ND AVE S - MARIE AVE	Unknown	7,530	120	$ 220,177	$ 120,000	$ -
	12346357	MENDOTA HTS - HWY 13 - WACHTER AVE	Unknown	911	5	$ 26,638	$ 5,000	$ 5,138
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	12403875	SARTELL - MISSISSIPPI RIVER CROSSING	1973	1,700	-	$ 136,000	$ -	$ -
	12249351	DELANO	Unknown	14,800	127	$ 432,752	$ 127,000	$ 190,478
Southeast	12385504	WINONA - 3RD ST BTW GALE ST-MECHANIC ST	1974	8,100	127	$ 236,844	$ 127,000	$ 77,222
	12354151	NORTHFIELD - FLORELLAS CT	1968	1,550	22	$ 45,322	$ 22,000	$ -
	12328936	FARIBAULT - 8TH ST SW	Unknown	5,320	48	$ 155,557	$ 48,000	$ 59,368
	12345274	FARIBAULT - 7TH ST NW	1980	4,900	43	$ 143,276	$ 43,000	$ -
	12350531	FARIBAULT - 8TH ST SW, BOTSFORD, CARLTON	Unknown	3,000	49	$ 87,720	$ 49,000	$ -
Moorhead	12359542	MOORHEAD - REGAL ESTATES	Unknown	10,500	210	$ 307,020	$ 210,000	$ 87,753
2016 DIMP-related Main Replacement Total				270,427	3,279	$ 7,993,577	$ 3,278,941	$ 3,835,636

*Project detail amounts vary from costs presented in Attachment C, due to extracting the data from different systems (PowerPlan vs. Passport) and non-recoverable costs associated with internal labor.

Northern States Power Company

DIMP Replacement Project Detail for 2017

NSP-MN Main & Services DIMP Replacement Projects 2017

Area	Work Order Number	Description	Year Retired Main was Installed	Total Design FT.	Tot. Svc	Anticipated Cost
St Paul	12294045	ROSEVILLE - FERNWOOD ST	1955	3,760	44	$109,942
	12315892	ST PAUL - CASE AVE BTN EDGERTON-EARL	1979	11,300	177	$330,412
	12328310	ST PAUL - HAGUE/SELBY	1978	6,745	128	$197,224
	12326608	ST PAUL - EDMOND	Unknown	5,290	113	$154,680
	N/A	ST PAUL - ST PETER, FORD 4TH	1963	4,200	62	$122,808
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	12320389	ARDEN HILLS - GLENPAUL AVE	Unknown	4,700	58	$137,428
	12319969	MAHTOMEDI - GRIFFIN AVE	1968	3,200	39	$93,568
	12092590	BAYPORT - 7TH ST	1964	1,000	11	$29,240
Wyoming	12320014	FOREST LAKE - 11TH AVE SW (LAKE ST)	Unknown	2,100	25	$61,404
	12320051	FOREST LAKE - 208TH-209TH ST	1969	4,000	47	$116,960
	12320027	FOREST LAKE - IVERSON AVE	1967	3,700	53	$108,188
	N/A	FOREST LAKE - HEATH AVE	1968	3,600	34	$105,264
Newport	12352434	COTTAGE GROVE - IRONWOOD	1971	3,338	100	$97,603
	12438126	ST PAUL - BURNS-RUTH	Unknown	11,715	147	$342,547
	DE 522036	COTTAGE GROVE - HYDE	1961	3,710	41	$108,480
	DE 521888	COTTAGE GROVE - PT DOUGLAS RD, IDEAL AVE	1961	4,735	56	$138,451
	DE 521609	COTTAGE GROVE - IDEAL-85TH ST	1962	4,160	36	$121,638
	DE 521021	MENDOTA HTS - BACHELOR-SUTTON-MARIE	1973	10,570	77	$309,067
	DE 526906	INVER GROVE HTS - DAWN-UPPER 75TH-77TH	1971	5,160	89	$150,878
	DE 519457	INVER GROVE HTS - CONROY CT	1972	5,400	142	$157,896
St Cloud	N/A	ST CLOUD - 16TH AVE - 3RD ST N	1972	4,100	26	$119,884
	12412846	ST CLOUD - 44TH AVE N, APPOLLO BY VA	1972	2,500	10	$73,100
Southeast	DE 525652	WINONA - 3RD ST BTW WINONA ST-LIBERTY ST	1968	8,500	154	$248,540
	12320940	NORTHFIELD - WOODLEY ST E	1977	500	13	$14,620
	12344771	NORTHFIELD - ARCHIBALD ST/ASTER	1981	3,500	55	$102,340
	12356426	LAKE CITY - LAKEWOOD AVE	1972	4,250	79	$124,270
	12360394	RED WING - SPRUCE/SOUTHWOOD	Unknown	6,000	86	$175,440
	12356414	WINONA - 9TH/52ND	1977	3,500	42	$102,340
	N/A	NORTHFIELD - EDWARDS LN	1968	1,660	42	$48,538
	DE 525650	RED WING - BUSH ST - PLUM ST	1983	3,250	76	$95,030
	N/A	RED WING - WRIGHT/FINRUD	1975	10,400	130	$304,096
Moorhead	12410474	MOORHEAD-MOBILE MANOR-1224 15TH AVE. N	1972	1,260	38	$36,842
	12422040	DILWORTH - 1ST AVE SE	1972	5,000	48	$146,200
2017 Designed DIMP-related Main Replacement Total				**168,703**	**2,453**	**$4,932,876**

*Remaining projects are in-process of development and design; this work will take place the last quarter of 2016 and the first two quarters of 2017.

* Actual costs are through December 31, 2015. Project detail amounts vary from costs presented in Attachment C, due to extracting the data from different systems (PowerPlan vs. Passport) and non-recoverable costs associated with internal labor.

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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	Information Request No.	17
Requestor:	Adam J. Heinen		
Date Received:	December 19, 2016		**Revised**

Question:

Reference: Attachment C1

Please list for each project the year in which the pipe replaced originally entered service.

If this information has already been provided in written comments or in response to an earlier DOC information request, please identify the specific comment cite(s) or DOC information request number(s).

Response:

Please see Attachment A to this response. Attachment A contains Petition Attachments C1(b), C1(c) and C1(d) modified to include the year the retired main was installed.

Revision:

After discussions with the Department of Commerce, we reviewed this response and discovered erroneous data. Seventeen of the "Year Retired Main was installed" dates (highlighted in green in Attachment A to this response) have been updated or revised in this response. Attachment A Revised is provided in live Excel spreadsheet format. The updated installed dates were obtained by going back to the original as-built records.

Preparer:	Eric Kirkpatrick	
Title:	Director – Gas Engineering	
Department:	Gas Engineering	
Telephone:	303-571-3223	
Date:	December 29, 2016	**Revised: February 24, 2017**

Northern States Power Company

Docket No. G002/M-16-

Gas Utility Infrastructure Cost Rider - 2017 Factors

DIMP Replacement Project Detail for 2015

Attachment C1(b)

NSP-MN Main & Services DIMP Replacements					Main Footage			Service			Service Cost
Division	Project	WO	Actual from Passport	Year Retired Main was Installed	Estimate	Actual Replaced	Actual Installed from Passport	Estimate	Replaced	Transferred	Actual Cost for Services
St Paul	STP/ARLINGTON, NEVADA, NEBRASKA BTN. WHITE BEAR & FURNESS	11935351	$660,033	1977	12,760	7,100	12,760	230	223	4	221,983
	ROSEVILLE/ COHANSEY ST. PROJECT/ INSTALL 7500' OF 2" PE	12118923	$222,657	1965	7,500	4,530	7,517	74	71	2	70,676
	STP / CLARENCE ST BTN ARLINGTON AVE E & HOYT AVE E / DIMP PR	12096468	$94,089	1967	2,600	1,300	1,300	48	46	4	45,790
	Barclay/Dieter	12185039	$206,308	Unknown	3,750	2,675	3,925	60	58	4	$57,736
	STP / IVY AVE E XST: RUTH ST / LOW PRESSURE DIMP PROJECT	12088590	$622,841	1953	16,000	11,350	16,031	218	224	0	$222,979
	STP / 7TH ST W BTN ALTON & RANKIN ST	12217850	$240,863	1972	2,326	4,660	2,326	24	21	4	$20,904
	Idaho / Barclay / Clarence	12227467	$318,811	1960	7,350	4,775	7,467	99	93	8	$92,576
	ROSEVILLE/ GALTIER ST/ INSTALL 4600' OF 2" PE MAIN (DIMP)	12122749	$142,754	Unknown	4,400	2,405	4,560	49	48	0	$47,781
White Bear Lake	VADNAIS HEIGHTS-5-STAR MOBILE ESTATES-INSTALL 10,480' 2" PE	12100647	$322,376	1974	10,480	9,225	10,124	190	112	77	$111,489
	LAKE ELMO-CIMARRON MOBILE HOME PARK-SOUTH HALF-RENEW MAIN	12148971	$498,317	1970	15,000	15,234	15,234	250	228	0	$226,960
	LAKE ELMO-CIMARRON MOBILE HOME PARK-NORTH HALF-RENEW MAIN*	12225339	$139,126	1970	16,709	16,064	16,709	252	237	0	$235,919
	WBL/OPH/Area D	12200298	$157,590	1962	5,000	4,520	5,097	12	14	7	$13,936
	Vad Heights - North Star Estates	12226824	$246,291	1972	10,000	7,040	9,485	172	161	8	$160,266
	BAYPORT 5TH ST S INSTALL 3900' OF 2"PE MAIN RENEW 43 SVCS	12093773	$128,522	Unknown	2,900	2,000	3,845	43	16	23	$15,927
	NO ST PAUL / 14th AVE E	11945105	$128,989	1978	3,865	2,105	3,999	48	40	6	$39,818
Wyoming	Forest Lake - Carry-over from 2014	12185020	$411,767	1968	9,000	10,850	8,741	93	68	28	$67,690
	Forest Lake - 11th Ave & 6th St	12233388	$112,887	1968	4,100	3,310	3,310	36	41	6	$40,813
	Forest Lake - 1st Ave / 2nd Ave / 8th St / 7th St / 6th St	12234310	$180,857	Unknown	4,650	3,750	4,642	27	43	9	$42,804
Newport	Cloman Way & Lower 67th St	12262781	$289,384	1971	5,500	3,900	6,322	152	154	0	$153,298
	ST PAUL PARK /2015 DIMP/ DIXON / BLOSSOM	12148969	$58,549	Unknown	2,204	950	2,224	26	26	0	$25,881
	2015 DIMP / ST PAUL PK / DIXON DR	12149144	$115,211	Unknown	2,581	1,600	2,549	29	29	0	$28,868
	2015 DIMP / ST PAUL PK / GARY/ SELBY / DAYTON	12149707	$229,296	Unknown	9,274	5,050	9,274	110	110	0	$109,498
	ST PAUL PARK / 2015 DIMP / PORTLAND AVE / 13TH / 15TH	12101212	$51,323	1972	1,800	1,240	1,764	16	11	5	$10,950
	SOUTH ST PAUL / 2015 DIMP / BUTLER / KASSAN	12089427	$74,096	1974	2,224	2,980	2,224	20	15	3	$14,932
	SOUTH ST PAUL / 2015 DIMP BUTLER AVE / BUTLER CT	12101218	$79,734	1974	2,298	1,200	2,298	30	26	6	$25,881
	Denton	12255539	$147,674	1973	4,828	4,220	4,828	75	75	0	$74,658
	Burns Ave	12170859	$244,420	Unknown	6,901	3,900	6,902	85	73	11	$72,667
St Cloud	DLH / DIMP / RIVER'S EDGE PARKING	12188957	$41,844	Unknown	250	256	270	2	0	0	$0
	St Cloud - Lincoln Ave*	12223516	$205,043	Unknown	7,750	5,990	6,273	36	18	11	$17,918
	Watertown	12162124	$312,454	Unknown	10,200	7,030	10,210	95	73	37	$72,667
	Sauk Rapids - 7th St NE (@ 2nd Ave NE)	12227154	$13,639	Unknown	286	250	250	3	3	0	$2,986
Southeast	GOODVIEW-LAKE VILLAGE MOBILE HOME PARK	12157111	$370,276	1974	9,989	6,930	8,455	230	192	0	$191,124
	Northfield Viking Ter	12241776	$399,697	1970	10,550	8,525	7,677	180	180	0	$179,179
	7th St S - Lake City	12205025	$74,600	1971	1,400	-	1,256	6	0	0	$0
	Hallstrom Dr & Burton St - Red Wing	12218584	$448,078	1971	17,000	14,482	14,482	270	136	25	$135,380
	Bluffview - Winona	12231997	$46,329	1971	2,000	1,120	1,626	5	12	3	$11,945
	Bush St & Langsford Ave - Red Wing	12212950	$256,974	1972	5,950	5,100	6,337	85	69	7	$68,685
	Hillsdale - Hidden Valley Mobile Home Park	12162836	$303,914	1976	10,064	8,115	10,699	185	176	0	$175,197
Moorhead	Moorehead 30th Ave & 8th St S	12215066 & 12208317	$25,256	Unknown	975	-		1	0	0	$0
	Moorehead Dale & 5th St S	12215099 & 12210767	$35,169	Unknown	1,608	-	1,599	32	0	0	$0
	Service Materials		$117,369								
		Totals	$8,775,406		254,022	195,731	244,591	3,598	3,122	298	$3,107,764

*Amounts vary from costs presented in Attachment E due to extracting the data from different systems (PowerPlan vs. Passport) and non-recoverable and non-GUIC recoverable costs associated with internal labor.

Northern States Power Company

Docket No. G002/M-16-___

Gas Utility Infrastructure Cost Rider - 2017 Factors

DIMP Replacement Project Detail for 2016

Attachment C1(c)

NSP-MN Main & Services DIMP Replacement Projects 2016

Area	Work Order Number	Description	Year Retired Main was Installed	Total Design FT.	Tot. Svc	Anticipated Main Cost	Anticipated Service Cost	GL Main Cost (2016 YTD August)
St Paul	12092489	ST PAUL - ARMSTRONG AVE XST: CHATSWORTH ST S	1990	1,350	28	$ 39,474	$ 28,000	$ 8,524
	12328949	ST PAUL - ARMSTRONG AVE	1990	7,506	150	$ 219,475	$ 150,000	$ 30,364
	12381180	ST PAUL - ATLANTIC, DULUTH & LARPENTEUR	1955	8,900	118	$ 260,236	$ 118,000	$ 33,905
	12294860	ROSEVILLE - GLENHILL, WOODLYNN, CLARMAR	1955	7,810	81	$ 228,364	$ 81,000	$ 12,230
	12398688	LAUDERDALE - EUSTIS ST	Unknown	1,100	17	$ 32,164	$ 17,000	$ 43,054
	12380740	ROSEVILLE - WEWERS RD	Unknown	1,400	15	$ 40,936	$ 15,000	$ 51,078
	12404989	ST PAUL - DOWNTOWN - 10TH-MINNESOTA	1957	1,200	5	$ 35,088	$ 5,000	$ 69,353
	12344852	ROSEVILLE - COUNTY RD C, FISK, AVON, GROTTO	1958	23,400	305	$ 684,216	$ 305,000	$ 641,601
	12444470	ST PAUL - DOWN TOWN (Kellogg)	1956	150	-	$ 4,386	$ -	$ -
	12361662	ST PAUL - JUNO CONTRACTOR PORTION	1980	4,750	56	$ 138,890	$ 55,882	$ 135,824
	12358730	ST PAUL - JUNO LOCAL PORTION	1980	1,260	20	$ 36,842	$ 20,000	$ 46,852
	12364882	ST PAUL - AURORA - LOCAL PORTION	1980	960	36	$ 28,070	$ 36,000	$ 37,637
	12369728	ST PAUL - AURORA - CONTRACTOR PORTION	1980	3,875	100	$ 113,305	$ 100,000	$ 13,299
	12317526	ST PAUL - BERKELY-STANFORD-WELLESLY	1980	10,440	195	$ 305,266	$ 195,000	$ 15,098
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	12352631	ST PAUL PARK - 13TH-14TH-CHICAGO	Unknown	8,815	100	$ 257,751	$ 100,000	$ -
	12346491	SOUTH ST PAUL - 2ND AVE S - MARIE AVE	Unknown	7,530	120	$ 220,177	$ 120,000	$ -
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	12403875	SARTELL - MISSISSIPPI RIVER CROSSING	1973	1,700	-	$ 136,000	$ -	$ -
	12249351	DELANO	Unknown	14,800	127	$ 432,752	$ 127,000	$ 190,478
Southeast	12385504	WINONA - 3RD ST BTW GALE ST-MECHANIC ST	1974	8,100	127	$ 236,844	$ 127,000	$ 77,222
	12354151	NORTHFIELD - FLORELLAS CT	1968	1,550	22	$ 45,322	$ 22,000	$ -
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2016 DIMP-related Main Replacement Total				**270,427**	**3,279**	**$ 7,993,577**	**$ 3,278,941**	**$ 3,835,636**

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Northern States Power Company

Docket No. G002/M-16-___
Gas Utility Infrastructure Cost Rider - 2017 Factors

DIMP Replacement Project Detail for 2017

Attachment C1(d)

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Area	Work Order Number	Description	Year Retired Main was Installed	Total Design FT.	Tot. Svc	Anticipated Cost
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	DE 521021	MENDOTA HTS - BACHELOR-SUTTON-MARIE	1973	10,570	77	$309,067
	DE 526906	INVER GROVE HTS - DAWN-UPPER 75TH-77TH	1971	5,160	89	$150,878
	DE 519457	INVER GROVE HTS - CONROY CT	1972	5,400	142	$157,896
St Cloud	N/A	ST CLOUD - 16TH AVE - 3RD ST N	1972	4,100	26	$119,884
	12412846	ST CLOUD - 44TH AVE N, APPOLLO BY VA	1972	2,500	10	$73,100
Southeast	DE 525652	WINONA - 3RD ST BTW WINONA ST-LIBERTY ST	1968	8,500	154	$248,540
	12320940	NORTHFIELD - WOODLEY ST E	1977	500	13	$14,620
	12344771	NORTHFIELD - ARCHIBALD ST/ASTER	1981	3,500	55	$102,340
	12356426	LAKE CITY - LAKEWOOD AVE	1972	4,250	79	$124,270
	12360394	RED WING - SPRUCE/SOUTHWOOD	Unknown	6,000	86	$175,440
	12356414	WINONA - 9TH/52ND	1977	3,500	42	$102,340
	N/A	NORTHFIELD - EDWARDS LN	1968	1,660	42	$48,538
	DE 525650	RED WING - BUSH ST - PLUM ST	1983	3,250	76	$95,030
	N/A	RED WING - WRIGHT/FINRUD	1975	10,400	130	$304,096
Moorhead	12410474	MOORHEAD-MOBILE MANOR-1224 15TH AVE. N	1972	1,260	38	$36,842
	12422040	DILWORTH - 1ST AVE SE	1972	5,000	48	$146,200
2017 Designed DIMP-related Main Replacement Total				**168,703**	**2,453**	**$4,932,876**

*Remaining projects are in-process of development and design; this work will take place
the last quarter of 2016 and the first two quarters of 2017.

* Actual costs are through December 31, 2015. Project detail amounts vary from costs presented in Attachment C, due
to extracting the data from different systems (PowerPlan vs. Passport) and non-recoverable costs associated with internal labor.

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Xcel Energy			
Docket No.:	G002/M-16-891		
Response To:	Department of Commerce	Information Request No.	6
Requestor:	Adam J. Heinen		
Date Received:	December 19, 2016		

Question:

Reference: Page 24

In the above reference, the Company stated the following:

Only the camera inspection aspect of the program is outsourced. At present, the Company has neither the internal expertise nor the equipment available to perform this specialized aspect of the program. By outsourcing the inspections, the Company has spared ratepayers the cost of expensive, specialized equipment, and ensured that those with the expertise are conducting the investigations.

Given the length and breadth of these GUIC projects, has the Company conducted a cost/benefit analysis substantiating Xcel's decision to outsource this work. If so, please provide these analyses. If not, please fully explain why Xcel has not conducted these type of analyses and also why recovery of these costs would be reasonable if the Company has not been able to justify them through a cost/benefit analysis.

If this information has already been provided in written comments or in response to an earlier DOC information request, please identify the specific comment cite(s) or DOC information request number(s).

Response:

The Company believes that the recovery of costs associated with this work is reasonable because it aligns with the eligibility requirements set forth in the Minnesota Statute § 216B.1635, supporting public safety for our customers. The Commission found (page 10 of Xcel Energy's 2017 GUIC Petition, Docket No. G002/M-16-891) that Company investments meet the statutory requirements for rider recovery as gas utility infrastructure costs.

The Company has not conducted a cost/benefit analysis related to the decision to outsource this work. Inspecting sewer lines for potential conflicts with natural gas lines is a unique activity that differs from normal activities associated with the installation, operations and maintenance of a gas system. Because of this uniqueness, the Company has not determined that investing in the ownership of the specialized equipment or training necessary to perform the work as practical.

As with other GUIC programs of work, the Company has established governance of the sewer mitigation project including monthly tracking of progress, expenditures, findings and strategy. This governance team meets on a monthly basis, and provides an annual update to the Minnesota Office of Pipeline Safety of progress and findings.

Preparer:	Katie Hellfritz
Title:	Senior Director
Department:	Gas Governance
Telephone:	303-571-3162
Date:	December 29, 2016

PUBLIC DOCUMENT
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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.

PUBLIC DOCUMENT
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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**

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.

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

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.

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.

Heinen, Adam (COMM)

From: Peterson, Lisa R <lisa.r.peterson@xcelenergy.com>
Sent: Friday, January 20, 2017 3:39 PM
To: Heinen, Adam (COMM)
Subject: GUIC - Pipeline Data Project costs

Hi Adam,

Amy passed along a question that you had regarding our Pipeline Data Project contract and associated expenses in the 16-891 GUIC petition. The contract was submitted under trade secret cover in Docket 15-808 OAG IR 9.1 attachment B, and in the interest of trying to keep this a non-Trade Secret response, we do not show a specific cost breakdown. I can send the trade secret information if you feel you need it, just let me know.

The costs outlined as DIMP software capital expenditures on Table 2 (page 25) and Attachment D (Page 1 of 1) of our 16-891 Petition represent the total project costs which include costs for both the vendor contract and the contract project team that was used to perform the QA/QC for the vendors deliverables within the project.

If you isolate the difference between the software capital expenditures of $2,073,169 shown on Attachment D of the 16-891 petition, and the (trade secret) contract amount on page 4 of OAG 9.1 Attachment B, that difference is made up of approximately 81% contract project team costs and 19% additional vendor contract costs. The company and the vendor agreed a change order was not required. Since the work was DIMP-related, it is direct assigned to MN.

In regard to the contract covering all Opcos, the contract reflects work done with the vendor that applies to multiple work orders that were performed over the contract period. In other words, the contract was used to achieve an agreement with the vendor but the work that is completed is charged to a unique work order (on the cover page of the agreement) for the operating company in which the work was designated. The detailed project description (Section I of Scope of Work) notes that the paper documents to be viewed are in various locations in NSPM. There are separate WOs for PSCO and NSPW. Only NSPM work was associated with the NSPM work order.

If you have questions, please let me know.
Thanks,
Lisa

Lisa Peterson
Principal Pricing Analyst
414 Nicollet Mall, 401 7th Floor, Minneapolis, MN 55401
P: 612.330.7681
E: lisa.r.peterson@xcelenergy.com

Heinen, Adam (COMM)

From: Peterson, Lisa R <lisa.r.peterson@xcelenergy.com>
Sent: Wednesday, February 22, 2017 5:08 PM
To: Heinen, Adam (COMM); Kundert, John (COMM)
Subject: GUIC discussion follow-up
Attachments: 16-0891 DOC Informal IR 002 Attachment C TRADE SECRET IN ENTIRETY.pdf

Adam and John,

Thank you for taking the time meet in person to discuss your questions regarding the GUIC pipeline data project. As you requested in the meeting, we provide follow-up on the items below:

- **PSCo service record data in GIS:**
  In the early to mid-1980's, Public Service of Colorado's (PSCO) Denver Metro and Boulder area gas distribution main data was converted from Mylar drawings to the Distribution Facilities Information System (DFIS). In the mid-1990's (around 1994), the Company migrated from DFIS to SmallWorld GIS, and PSCo's Northern and Western Division gas distribution main data was also incorporated into the GIS system from Mylar drawings.

  In approximately May 2006, a project was initiated to extract data from all paper gas service records and populate said data into SmallWorld. This project was completed in approximately September of 2007. The total scope of the project was to address all the gas services for the Denver, Boulder, Northern and Western divisions. The project scope included acquiring the as-built records from the Divisions, scanning and index records for future access, extracting data from the records, and updating the GIS with the extracted data.

  Following the 2006 gas service record conversion, a project was initiated to convert gas service records for the rest of the Colorado rural divisions (Pueblo, San Luis Valley, Front Range, Mountain and High Plains). This project started September 2007 and was complete the end of 2008, with the same scope listed above.

- **Costs not eligible for GUIC:**
  As discussed in our response to Informal IR 2, the Company's 2017 GUIC request included $49,945 in costs that should not have been charged to the GUIC. I mischaracterized these costs in our meeting and would like to clarify that these were costs incurred for the Company's MAOP project in PSCo, as can be seen in the attached invoices.

- **Model review costs:**
  I have confirmed that the dollars for the PricewaterhouseCoopers model review in our response to DOC IR 25 part B are not being recovered through the GUIC Rider.

I think we covered the rationale for your remaining issues in the meeting, such as the use of a least cost common vendor given the Minnesota scope was similar to PSCo, the use of contract labor to complete the project in a timely manner, and the process of data acceptance testing and vendor process refinement given the complexity of the historical documents.

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

Lisa Peterson
Manager, Regulatory Analysis
414 Nicollet Mall, 401 7th Floor, Minneapolis, MN 55401
P: 612.330.7681
E: lisa.r.peterson@xcelenergy.com

CERTIFICATE OF SERVICE

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

Minnesota Department of Commerce
Public Comments

Docket No. G002/M-16-891

Dated this 1st day of March 2017

/s/Sharon Ferguson

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota St St. Paul, MN 551012134	Electronic Service	Yes	OFF_SL_16-891_M-16-891
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_16-891_M-16-891
Alison C	Archer	alison.c.archer@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 5 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_16-891_M-16-891
Gail	Baranko	gail.baranko@xcelenergy.com	Xcel Energy	414 Nicollet Mall7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_16-891_M-16-891
William A.	Blazar	bblazar@mnchamber.com	Minnesota Chamber Of Commerce	Suite 1500 400 Robert Street North St. Paul, MN 55101	Electronic Service	No	OFF_SL_16-891_M-16-891
George	Crocker	gwillc@nawo.org	North American Water Office	PO Box 174 Lake Elmo, MN 55042	Electronic Service	No	OFF_SL_16-891_M-16-891
Carl	Cronin	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_16-891_M-16-891
Jeffrey A.	Daugherty	jeffrey.daugherty@centerpointenergy.com	CenterPoint Energy	800 LaSalle Ave Minneapolis, MN 55402	Electronic Service	No	OFF_SL_16-891_M-16-891
Ian	Dobson	ian.dobson@ag.state.mn.us	Office of the Attorney General-RUD	Antitrust and Utilities Division 445 Minnesota Street, 1400 BRM Tower St. Paul, MN 55101	Electronic Service	No	OFF_SL_16-891_M-16-891
Rebecca	Eilers	rebecca.d.eilers@xcelenergy.com	Xcel Energy	414 Nicollet Mall - 401 7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_16-891_M-16-891

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Emma	Fazio	emma.fazio@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_16-891_M-16-891
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_16-891_M-16-891
Edward	Garvey	garveyed@aol.com	Residence	32 Lawton St Saint Paul, MN 55102	Electronic Service	No	OFF_SL_16-891_M-16-891
Todd J.	Guerrero	todd.guerrero@kutakrock.com	Kutak Rock LLP	Suite 1750 220 South Sixth Street Minneapolis, MN 554021425	Electronic Service	No	OFF_SL_16-891_M-16-891
Annete	Henkel	mui@mnutilityinvestors.org	Minnesota Utility Investors	413 Wacouta Street #230 St.Paul, MN 55101	Electronic Service	No	OFF_SL_16-891_M-16-891
Sandra	Hofstetter	sHofstetter@mnchamber.com	MN Chamber of Commerce	7261 County Road H Fremont, WI 54940-9317	Electronic Service	No	OFF_SL_16-891_M-16-891
Michael	Hoppe	il23@mtn.org	Local Union 23, I.B.E.W.	932 Payne Avenue St. Paul, MN 55130	Electronic Service	No	OFF_SL_16-891_M-16-891
Richard	Johnson	Rick.Johnson@lawmoss.com	Moss & Barnett	150 S. 5th Street Suite 1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_16-891_M-16-891
Michael	Krikava	mkrikava@briggs.com	Briggs And Morgan, P.A.	2200 IDS Center 80 S 8th St Minneapolis, MN 55402	Electronic Service	No	OFF_SL_16-891_M-16-891
Amy	Liberkowski	amy.a.liberkowski@xcelenergy.com	Xcel Energy	414 Nicollet Mall 7th Floor Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_16-891_M-16-891

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
John	Lindell	john.lindell@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	Yes	OFF_SL_16-891_M-16-891
Eric	Lipman	eric.lipman@state.mn.us	Office of Administrative Hearings	PO Box 64620 St. Paul, MN 551640620	Electronic Service	Yes	OFF_SL_16-891_M-16-891
Matthew P	Loftus	matthew.p.loftus@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 5 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_16-891_M-16-891
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	OFF_SL_16-891_M-16-891
Mary	Martinka	mary.a.martinka@xcelenergy.com	Xcel Energy Inc	414 Nicollet Mall 7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_16-891_M-16-891
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_16-891_M-16-891
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_16-891_M-16-891
David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency	220 South Sixth Street Suite 1300 Minneapolis, Minnesota 55402	Electronic Service	No	OFF_SL_16-891_M-16-891
Richard	Savelkoul	rsavelkoul@martinsquires.com	Martin & Squires, P.A.	332 Minnesota Street Ste W2750 St. Paul, MN 55101	Electronic Service	No	OFF_SL_16-891_M-16-891
James M.	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	470 U.S. Bank Plaza 200 South Sixth Street Minneapolis, MN 55402	Electronic Service	No	OFF_SL_16-891_M-16-891

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Cam	Winton	cwinton@mnchamber.com	Minnesota Chamber of Commerce	400 Robert Street North Suite 1500 St. Paul, Minnesota 55101	Electronic Service	No	OFF_SL_16-891_M-16-891
Daniel P	Wolf	dan.wolf@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_16-891_M-16-891