BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION
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MPUC Docket No. G-012/M-16-891

In the Matter of the Petition of Xcel Energy
For Approval of a Gas Utility Infrastructure
Cost Rider Compliance Filing, and Annual Report for 2017

INITIAL COMMENTS
OF THE OFFICE OF THE ATTORNEY GENERAL
RESIDENTIAL UTILITIES AND ANTITRUST DIVISION

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STATE OF MINNESOTA
BEFORE THE PUBLIC UTILITIES COMMISSION

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In the Matter of the Petition of Xcel Energy For Approval of a Gas Utility Infrastructure Cost Rider Compliance Filing, and Annual Report for 2017

DOCKET NO. G-002/M-16-891

COMMENTS OF THE OFFICE OF THE ATTORNEY GENERAL

The Office of the Attorney General—Residential Utilities and Antitrust Division ("OAG") submits the following Comments in response to the petition of Northern States Power Company, doing business as Xcel Energy, for approval by the Minnesota Public Utilities Commission ("Commission") of recovery of its updated gas utility infrastructure cost ("GUIC") rider for 2017. These Comments will first provide background information on the GUIC statute and Xcel's 2017 GUIC request before moving into an overview of pipeline safety and risky pipelines across the country and the state. This background information is important to put Xcel's GUIC projects into context with the flurry of activity happening elsewhere. Then, following the establishment of this contextual information, the Comments will provide analysis on three topics: concerns regarding Xcel's 2017 GUIC rider petition, its supplemental filing on performance metrics, and on its proposed return on equity. Each section of analysis will describe recommendations for the Commission. In summary, these Comments recommend that the Commission should take action to:

1. Establish a 6 percent revenue cap to protect Xcel's ratepayers due to concerns regarding the Company's historical replacement rate in comparison to its GUIC replacement rate, mission creep, and confusing risk assessment methodologies;
2. Require the Company to file a more detailed cost and revenue study or initiate an investigation requiring the Company to demonstrate that its current rates are set at a just and reasonable level;
3. Decline, at this time, to adopt Xcel's proposed performance metrics, require the Company to file results from its AGA information request, and initiate a separate docket to begin a broader discussion on the development of performance metrics with Xcel, other gas utilities, and other interested parties; and
4. Find that the Company's proposed return on equity of 9.50 percent is not reasonable and should not be adopted in this docket. The Multi-Stage DCF analysis proposed in these Comments, using OECD growth data and a more appropriate proxy group, results in an ROE that is in the public interest. The Commission should thus set the ROE in this proceeding at 7.13 percent.

BACKGROUND

Four figures provide useful context when considering Xcel's 2017 GUIC rider petition: $22 million, $50 million, $120 million, and $300 million. First, on November 1, 2016, Xcel Energy filed its third GUIC rider petition, requesting approximately $22 million in revenue through the rider mechanism for 2017 costs and a nearly four-fold increase in the per-therm rate paid by residential customers from 2016.[1] Second, Commission approval of Xcel's request in this petition would represent more than $50 million of revenue generated via this recovery

[1] Xcel's Initial Petition at 32.

mechanism over the three years covered by the rider to date.[2] Third, the Company projects that it will need nearly $120 million in additional revenue over the next four years (2018–2021) that will likely be collected via the GUIC rider.[3] And fourth, Xcel is in the midst of a $300 million capital investment cycle that, by the nature of its request for recovery via the GUIC rider, will not generate additional sales like normal utility investments and, because Xcel will likely request cost recovery via the GUIC rider, it reduces its financial risk while existing ratepayers are on the hook to pay the additional revenue requirements.[4]

These figures provide color and context to the notion that the Company is in the midst of a significant capital expenditure on a programs that it has in the past described as "continu[ing] indefinitely."[5] These investments are significant, especially when compared to the base revenue and capital expenditures approved in its most recent rate case in 2010.[6] The GUIC capital expenditures are projected to be as high as 167.26 percent (in 2019) of the capital expenditures approved in the Company's last rate case; in fact, 2017 is the only year between 2015 and 2021 where capital expenditures do not exceed the capital expenditures from the 2010 rate case.[7] Further, the revenue collected via GUIC already represents nearly 10 percent of base revenue in 2017, and will represent nearly 20 percent of the base revenue by 2021.[8]

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[2] In prior GUIC dockets, the Company has received approval for rider recovery of approximately $15 million (Docket No. 14-336) and $15.5 million (Docket No. 15-808) for its GUIC-eligible activities.

[3] Xcel's Initial Petition at Attachment M.

[4] *Id.* at 25 (noting that it plans to spend $190.3 million on its transmission system and $109.7 million on its distribution system between 2012 and 2021).

[5] *In the Matter of the Petition of Northern States Power Company for Approval of a 2016 Gas Utility Infrastructure Cost Rider*, MPUC Docket No. G-002/15-808, Xcel's Initial Petition at 20 (Oct. 30, 2015). This year's Initial Petition states only that TIMP projects "will continue beyond 2017." Xcel's Initial Petition at 26.

[6] The Company's last rate case, which featured a 2010 test year, is Docket No. 09-1153.

[7] Xcel's Initial Petition at Attachment L.

[8] It appears that the 10 percent number is based on a projection of the revenue collected in 2017 ($14.726 million) as opposed to the revenue required in 2017 ($22.138 million), a discrepancy that appears to be created by the recovery periods that extend across calendar years.

This sustained flurry of activity surrounding safety-related capital investments is not unique to Xcel; gas utilities across the state and the country are investing billions of dollars in the replacement of legacy gas distribution systems. In some of the most significant examples across the U.S., gas utilities are spending billions of dollars to remove cast iron and bare steel pipes, some of which were installed in the late-1800s.[9]

The safety of natural gas distribution systems in Minnesota is, rightly, a principal concern of utilities, regulators, and consumer advocates like the OAG. All Minnesotans benefit from a safe and reliable natural gas distribution system. But engagement from all participants is necessary to ensure that companies recover only those costs that are reasonably and prudently incurred. While cost-effectiveness is always an important consideration, it is especially relevant when cost recovery is sought in an extraordinary manner, via the GUIC rider, and when existing ratepayers bear all of the additional costs.

This section of the Comments will first describe the legal framework created by the GUIC statute and the various projects for which Xcel proposes GUIC rider cost recovery. Then, the rest of the section will provide information to help place Xcel's GUIC-related investments in the context of infrastructure-related initiatives across the country and elsewhere within the state. In particular, this section will explore the federal regulations that are driving utilities' TIMP and DIMP-related activities as well as the system threats that are being addressed by these programs. This review will demonstrate that Xcel's GUIC program is not being conducted in a vacuum and that a look to other Minnesota utilities and to other jurisdictions is necessary to be able to analyze Xcel's program in a meaningful way.

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[9] *See* U.S. Pipeline & Hazardous Materials Safety Admin., *Cast and Wrought Iron Inventory*, https://opsweb.phmsa.dot.gov/pipeline_replacement/cast_iron_inventory.asp (last accessed Feb. 17, 2017) (describing the history of cast iron pipe installations in the U.S.).

I. LEGAL FRAMEWORK FOR ANALYSIS OF COSTS REQUESTED FOR RECOVERY UNDER THE GUIC STATUTE.

The GUIC statute allows the Commission to approve eligible gas utility infrastructure costs that are incurred as "required by a federal or state agency."[10] In order to approve GUIC costs, the Company must demonstrate that the "costs included for recovery through the rate schedule are prudently incurred and achieve gas facility improvements at the lowest reasonable and prudent cost to ratepayers."[11]

Eligible GUIC costs are defined by three factors. First, the costs cannot be incurred for projects that "serve to increase revenues by directly connecting the infrastructure replacement to new customers."[12] This has a significant impact on existing ratepayers because it means that none of the projected $300 million in capital spending can generate additional revenue or serve to add new customers. Existing customers thus bear all of the incremental revenue required by the Company via the GUIC rider, which is projected to be $23 per year for the average customer in 2017 and increasing to nearly $50 per year four years from now, in 2021.[13]

Second, costs must be incurred for projects that are "in service but were not included in the gas utility's rate base in its most recent general rate case."[14] In order for a project to be eligible under this factor, the Company must demonstrate that the revenue requirements associated with capital projects are not already being taken into account in the rates established in its most recent general rate case. This factor reflects the policy priority to accelerate the replacement of risky pipes without allowing the utility to double-recover costs that are already reflected in base rates.

[10] Minn. Stat. § 216B.1635 (2016).
[11] Minn. Stat. § 216B.1635, subd. 5 (2016).
[12] Minn. Stat. § 216B.1635, subd. 1(b)(1) (2016).
[13] Xcel's Response to OAG Information Request No. 97 (in Appendix A).
[14] Minn. Stat. § 216B.1635, subd. 1(b)(2) (2016).

Third, GUIC-eligible costs cannot be incurred for projects that "constitute a betterment" unless specifically required by "a political subdivision or a federal or state agency."[15] In a prior GUIC order, the Commission noted that finding a precise definition of betterment is difficult, but that the "closest" definition is that it is "an improvement that goes 'beyond repair or restoration' rises to the level of a betterment."[16] While the Company indicated in its supplemental petition that its Rider Review Committee reviews potential GUIC projects to remove betterments, it did not provide a list of instances where the committee removed a project determined to be a betterment from its GUIC rider.[17] In response to an information request, however, the Company did identify one instance in the GUIC program where a project triggered an "advanced oversight process" whereby the Company removed the incremental costs associated with an 8-inch pipe compared to a 4-inch pipe.[18]

The GUIC statute also defines an eligible gas utility project. The relevant portion of this definition is as follows:

> [R]eplacement or modification of existing natural gas facilities, including surveys, assessments, reassessment, and other work necessary to determine the need for replacement or modification of existing infrastructure *that is required* by a federal or state agency.[19]

This definition ties into the Commission's obligation to ensure that costs requested to be recovered via GUIC are prudently incurred and achieve improvements to the system "at the lowest reasonable and prudent cost to ratepayers."[20] As noted in prior comments, it is difficult

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[15] Minn. Stat. § 216B.1635, subd. 1(b)(3) (2016).
[16] *In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of a Gas Utility Infrastructure Cost Rider*, MPUC Docket No. G-002/M-14-336, Order Approving Rider with Modifications at 10 (Jan. 27, 2015).
[17] Xcel's Supplemental Petition at Attachment A, slide 23.
[18] Xcel's Response to OAG Information Request No. 46 (Appendix A).
[19] Minn. Stat. § 216B.1635 subd. 1(c)(2) (2016).
[20] Minn. Stat. § 216B.1635 subd. 5 (2016).

for parties lacking technical engineering expertise to meaningfully analyze the engineering details of Xcel's vast array of integrity management projects.

The next section will summarize the components of Xcel's 2017 GUIC rider petition.

II. XCEL'S 2017 GUIC RIDER PETITION.

Xcel requested $22.14 million of revenue to be collected in its 2017 GUIC rider petition. Capital-related TIMP and DIMP[21] revenue requirements comprise approximately half of the request, at $12.0 million. Projected 2017 operations and maintenance expenses comprise $5.7 million of the request. Finally, the 5-year amortization of deferred costs related to sewer/gas line conflict remediation project total $4.55 million. The Company also requested a return-on-equity of 9.50 percent that results in a 7.26 percent overall return when taking into account its proposed cost of debt and capital structure.

Xcel's integrity management[22] projects are designed to address risk identified on its high-pressure transmission system and on the lower-pressure distribution system that ultimately delivers natural gas to homes and businesses. The projects to address risks on the transmission system are distinct from those that are intended to address risks on the distribution system. First, an explanation of Xcel's transmission-related integrity management projects, which are related to work done under its TIMP plan. There are three main projects[23] in Xcel's 2017 TIMP plan, which focuses on the Company's 77 miles of high-pressure transmission pipeline. The Transmission Pipeline Assessment project is expected to incur approximately $3 million in

[21] TIMP stands for Transmission Integrity Management Program and DIMP stands for Distribution Integrity Management Program.
[22] The term "integrity management" is used throughout these Comments to describe the activities undertaken by Xcel and other utilities to address system risks, such as pipeline replacement or in-line inspections.
[23] The Company's East Metro Pipeline Replacement project was planned to end in 2016 and the only costs expected to be incurred in 2017 relate to "carryover costs." Xcel's Initial Petition at Attachment B, p. 6.

capital and O&M costs in 2017.[24] The Automatic Shutoff Valve and Remote Controlled Valve project is expected to incur approximately $0.9 million of capital costs in 2017.[25] And Xcel's Programmatic Replacement / MAOP Remediation project begins work in 2017 with nearly $3 million in capital spending and it is expected to grow to $26.6 million in 2018, continuing at that level of spending through at least 2021.[26]

The Company describes six distribution-related projects that fall under its DIMP program in 2017. The two largest are its Poor Performing Main Replacements project and its Poor Performing Service Replacements project. The Poor Performing Main Replacement project is projected to incur $11 million in capital spending in 2017 to replace Aldyl-A plastic mains, vintage copper risers, and "additional material types based on their overall relative risk."[27] The Company plans to replace over 75 miles of main, of which 44 miles remain "Not Identified."[28] Xcel also plans to spend nearly $7 million on service replacements which will target 7,625 services, of which over 5,000 were still unidentified at the time of filing.[29] The rest of Xcel's DIMP projects are as follows: the Intermediate Pressure Line Assessments, Distribution Valve Replacement, Sewer and Gas Line Conflict Investigation, and Federal Code Mitigation.

The Company states that these GUIC projects emanate from requirements established by the federal Pipeline and Hazardous Materials Safety Administration ("PHMSA"), the agency that has promulgated rules for TIMP and TIMP. The next section will describe these programs, including what they require and what they do not, in greater detail. The next section will also cover the pipe materials that pose the highest risk to gas distribution systems across the country

[24] Xcel's Initial Petition at Attachment B, p. 5.
[25] *Id.*
[26] *Id*. at 4–5, 25.
[27] *Id.* at Attachment C, p. 4–6.
[28] *Id.* at 5.
[29] *Id.* at 7.

and in Minnesota. This information is necessary for the Commission and others to have a more clear understanding of how Xcel's GUIC activities fit in with activities that other gas utilities are undertaking to address system threats.

III. TIMP, DIMP, AND HIGH-RISK PIPELINE MATERIALS IN THE U.S.

Two acronyms drive much of the integrity management discussion—and spending—in Xcel's GUIC rider petition: TIMP and DIMP. TIMP, or the Transmission Integrity Management Program, describes a series of federal regulations that are overseen by PHMSA.[30] The TIMP rule was published in 2003. It establishes requirements for operators of high-pressure transmission pipelines to "develop integrity management programs for gas transmission pipelines located where a leak or rupture could do the most harm."[31] DIMP, or the Distribution Integrity Management Program, was created via PHMSA rulemaking in 2009.[32] DIMP is "less prescriptive" than its transmission-related rule counterpart, meaning that it provides less specific requirements, and instead establishes a series of goals for pipeline owners.[33] It requires the development and implementation of a management plan that emphasizes system knowledge, threat and risk identification and quantification, performance evaluation, and regular program evaluation.[34]

In addition to the TIMP and DIMP rules, PHMSA has urged gas utilities and states to take action to remove the highest risk materials from distribution and transmission systems. Most notably, PHMSA issued a *Call to Action* in 2011, following several pipeline incidents. The

[30] 49 C.F.R. pt. 192, subpt. O.
[31] Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines), 68 Fed. Reg. 69,778, 69,778 (Dec. 15, 2003) (to be codified at 49 C.F.R. pt. 192, subpt. O).
[32] Pipeline Safety: Integrity Management Program for Gas Distribution Pipelines, 74 Fed. Reg. 63,906 (Dec. 4, 2009) (to be codified at 49 C.F.R. pt. 192, subpt. P).
[33] *In the Matter of the Petition of Northern States Power Co., d/b/a Xcel Energy, for Approval of a Gas Utility Infrastructure Cost Rider*, MPUC Docket No. G-002/M-14-336, Xcel's Initial Petition at 8 (Aug. 14, 2014).
[34] 49 C.F.R. § 192.1007.

Call to Action encouraged the acceleration of the "rehabilitation, repair, and replacement of high-risk pipeline infrastructure."[35] PHMSA listed cast iron and bare steel as among the highest-risk pipe materials and it has focused its efforts to encourage and track the removal of cast iron and bare steel across the country via annual reporting.[36] The next section will describe why these two materials pose a higher risk than others and will present data on their prevalence in the country and how system composition impacts causes of leaks.

A. Cast iron and bare steel pipes pose a significant risk to distribution systems where they are prevalent.

One of the goals of the TIMP and DIMP regulations is to ensure that utilities take action to remove the type of pipes that are particularly troublesome—cast iron and bare steel mains. Many states nationwide have embarked on significant investment programs to remove these types of materials from their distribution systems, in part because they have a significantly higher propensity to leak.[37] It is important to recognize, however, that Xcel's distribution system includes very little cast iron or bare steel main—and, thus, Xcel's system does not face the same type of problems that has led other states to invest significantly to remove these types of materials. This section will describe why cast iron and bare steel present particularly high risk to the system.

As of 2012, the vast majority (approximately 97 percent) of installed distribution pipelines in the U.S. were made of plastic or steel, with the remaining 3 percent consisting

[35] U.S. Pipeline & Hazardous Materials Safety Admin., *White Paper on State Pipeline Infrastructure Replacement Programs* 1 (Prepared for Nat'l Ass'n of Regulatory Comm'rs, 2011).
[36] *Id.* at 4–5 (also noting that mechanical coupling, certain vintages of plastic pipe, inadequate records, and pipe age should be considered higher risk).
[37] Xcel included a summary of replacement activities in a number of states in Attachment S of its Initial Petition, beginning at page 93.

mostly of iron pipe.[38] This iron pipe can be particularly problematic. According to PHMSA, 10.2 percent of incidents on gas distribution mains involve cast iron, which only makes up 2.3 percent of all distribution mains.[39] In addition, a much higher percentage of incidents involving cast iron main result in a fatality or injury compared to other pipe materials.[40]

Bare steel pipes, which were used extensively until the 1960s, can also be problematic. Despite these problems, some operators continued to install bare steel until 1971, when federal regulations required a coating for steel pipes.[41] The age and lack of coating makes bare steel a higher risk compared to other materials that may be targeted by accelerated replacement programs.[42]

Given the risks posed by cast iron and bare steel mains and services, state and federal safety regulators have encouraged the prioritization of these materials for removal. In the past decade, states have made strides in the removal of cast iron and bare steel from distribution systems. The amount of installed cast iron mains have been reduced from 39,342 miles in 2005 to 27,771 miles in 2015, a reduction of approximately 30 percent. The number of cast iron services has been reduced from 34,466 services in use in 2005 to 10,028 services in 2015, a reduction of approximately 70 percent. The amount of bare steel mains have been reduced from 69,798 miles in 2005 to 51,877 miles in 2015, a reduction of approximately 25 percent. The number of bare steel services have been reduced from 4.1 million in 2005 to 2.1 million in 2015, a reduction of approximately 50 percent. Table 1 below summarizes progress across the country.

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38 U.S. Pipeline & Hazardous Materials Safety Admin., *Pipeline Replacement Updates*, https://opsweb.phmsa.dot.gov/pipeline_replacement/default.asp (last visited Feb. 9, 2017).
39 U.S. Pipeline & Hazardous Materials Safety Admin., *Cast and Wrought Iron Inventory*, https://opsweb.phmsa.dot.gov/pipeline_replacement/cast_iron_inventory.asp (last visited Feb. 9, 2017).
40 *Id*.
41 U.S. Pipeline & Hazardous Materials Safety Admin., *Bare Steel Inventory*, https://opsweb.phmsa.dot.gov/pipeline_replacement/bare_steel_inventory.asp (last visited Feb. 9, 2017).
42 U.S. Pipeline & Hazardous Materials Safety Admin., *Pipeline Replacement Updates*, https://opsweb.phmsa.dot.gov/pipeline_replacement/default.asp (last visited Feb. 9, 2017).

Table 1. Cast Iron and Bare Steel Mains and Services in the U.S. between 2005 and 2015.[43]

Description	2005	2015	% Reduction
Cast Iron Mains	39,342 miles	27,771 miles	(29.4%)
Cast Iron Services	34,466 services	10,028 services	(70.9%)
Bare Steel Mains	69,798 miles	51,877 miles	(25.7%)
Bare Steel Services	4,146,310 services	2,119,743 services	(48.9%)

The prevalence of cast iron and bare steel in distribution systems varies widely across the country. Some states, such as New Jersey, New York, and Massachusetts, had distribution systems with at least 3,000 miles of cast iron mains remaining in-service at the end of 2015. Figure 1, below, shows the distribution of miles of cast iron mains by state. Minnesota is 30th on the list with approximately 10 miles of cast iron main remaining at the end of 2015, all of which is in CenterPoint Energy's distribution system.[44] Minnesota has no cast iron services remaining.[45]

[43] Data on cast iron and bare steel mains and services are collected from a PHMSA database. *Id.*
[44] According to the most up-to-date data from PHMSA, CenterPoint Energy had 9.6 miles of cast iron remaining in its system at the end of 2015. Xcel last reported cast iron mains in 2011. U.S. Pipeline & Hazardous Materials Safety Admin., *Cast and Wrought Iron Inventory*, https://opsweb.phmsa.dot.gov/pipeline_replacement/cast_iron_inventory.asp (last visited Feb. 9, 2017).
[45] *See* Appendix B for a table of the states with cast iron services at the end of 2015.

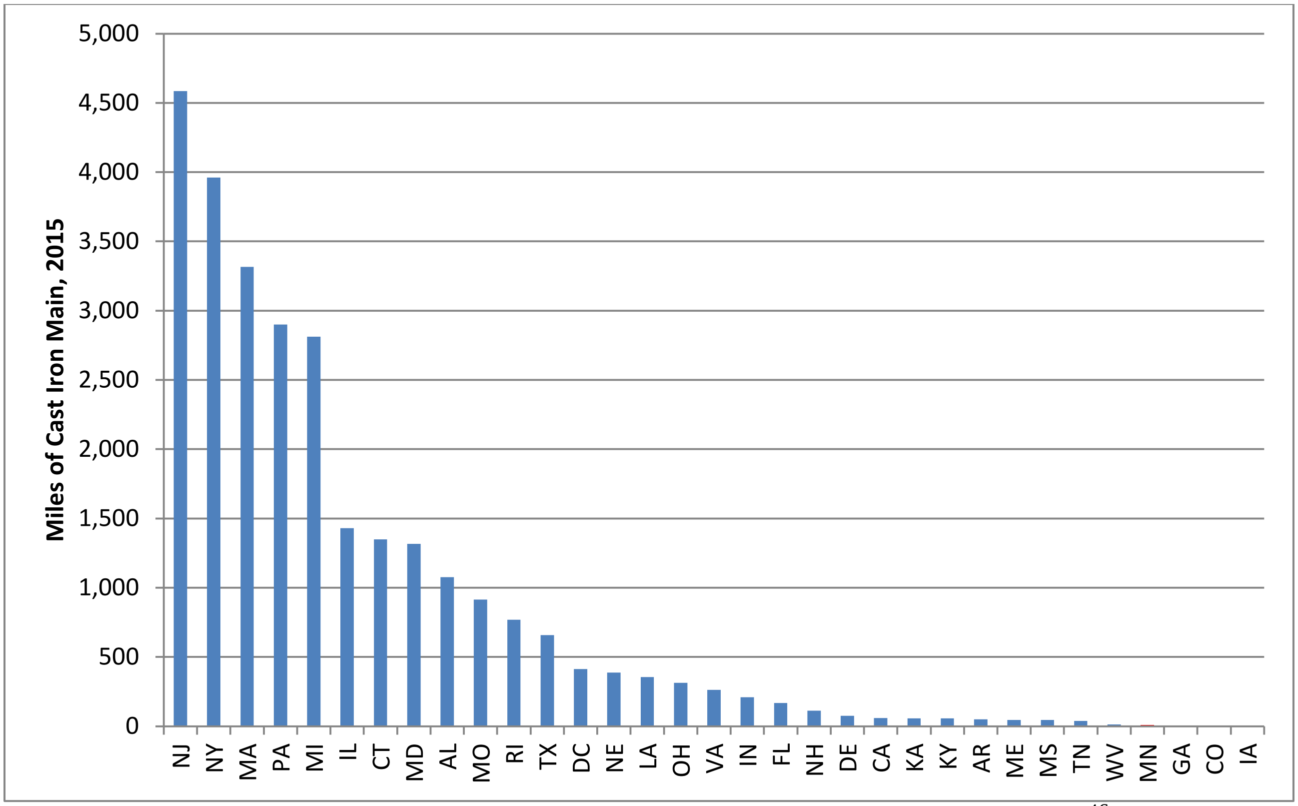

Figure 1. Miles of cast iron mains remaining in-service at the end of 2015, by state.[46]

The distribution of bare steel mains and services across the country is similarly lopsided, with Ohio, Pennsylvania, New York, and Texas atop the list, each with at least 5,000 miles of bare steel main at the end of 2015. Minnesota has about 350 miles of bare steel main remaining in its system at the end of 2015, the vast majority of which (over 99 percent) is found in CenterPoint Energy's distribution system.[47] Xcel's system has a negligible amount of bare steel remaining (less than one mile).[48] Figure 2, below, shows the miles of bare steel remaining by state.

[46] U.S. Pipeline & Hazardous Materials Safety Admin., *Cast and Wrought Iron Inventory*, https://opsweb.phmsa.dot.gov/pipeline_replacement/cast_iron_inventory.asp (last visited Feb. 9, 2017) (Appendix B).
[47] *See* Table 3.
[48] *See* Table 2.

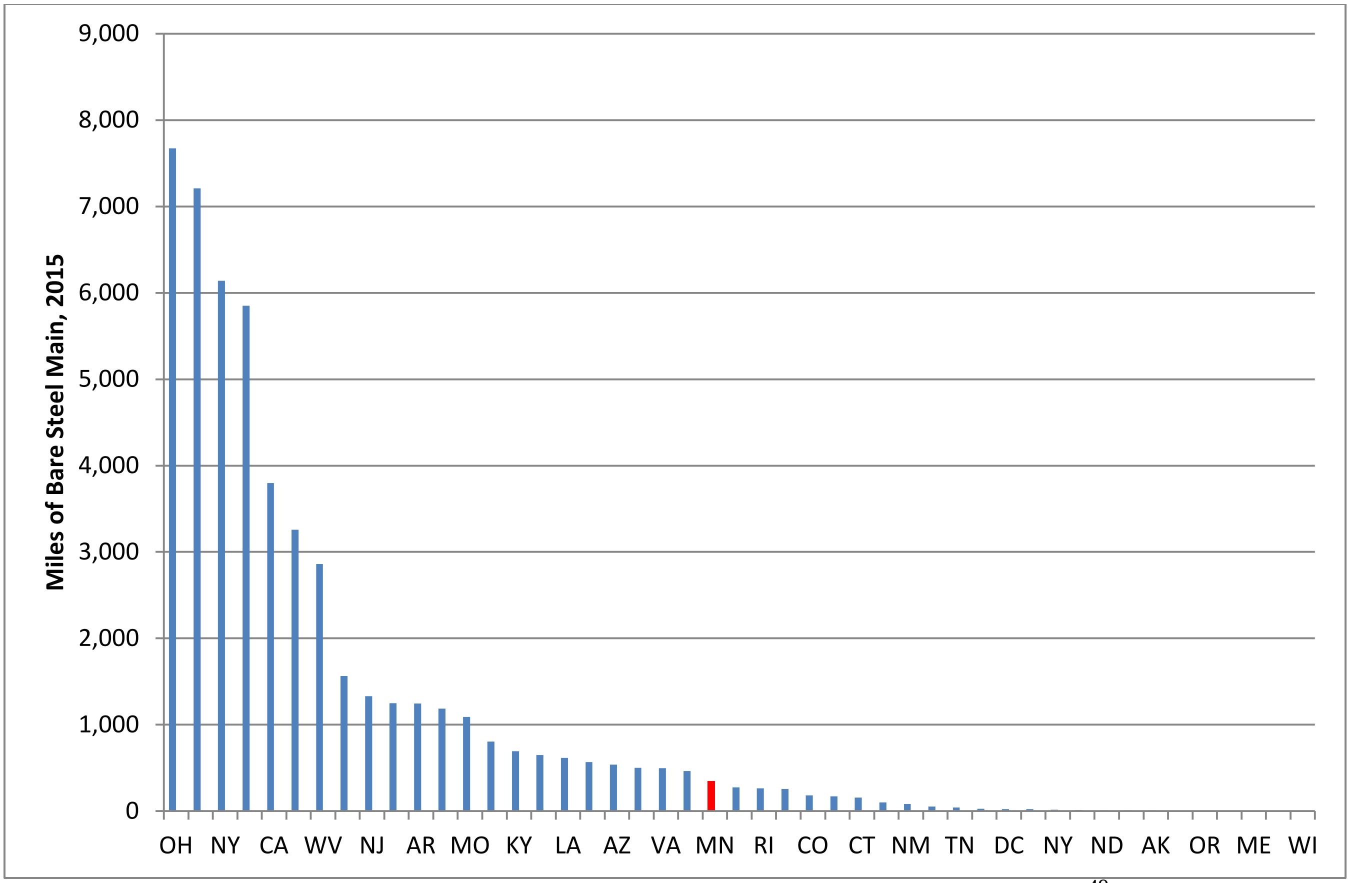

Figure 2. Miles of bare steel main remaining in-service at the end of 2015, by state.[49]

Studies have shown a correlation between the percentage of older, replacement-candidate[50] pipes and system leak rates. A recent study of three metropolitan areas—Washington, DC, Boston, and Manhattan—with a high percentage of cast iron or bare steel materials found *system* leak rates as high as 4.28 leaks-per-mile.[51] For comparison, this leak rate

[49] U.S. Pipeline & Hazardous Materials Safety Admin., *Bare Steel Inventory*, https://opsweb.phmsa.dot.gov/pipeline_replacement/bare_steel_inventory.asp (last visited Feb. 9, 2017). A larger reproduction of Figure 2 can be found in Appendix B.

[50] Bare steel, unprotected coated steel, cast/wrought/ductile iron, and copper are considered replacement candidate materials, with a "small proportion" of plastic pipe also considered a replacement candidate in some areas. Am. Gas Found., *Gas Distribution Infrastructure: Pipeline Replacement and Upgrades* 3–4 (2012).

[51] Morgan E. Gallagher et al., *Natural Gas Pipeline Replacement Programs Reduce Methane Leaks and Improve Consumer Safety*, 2 Envt'l Sci. & Tech. Letters 286, 288 (2015) (noting that cities with successful pipeline replacement programs, such as Cincinnati, OH and Durham, NC, have significantly fewer leaks per mile than cities without such programs and with a high percentage of replacement candidate mains).

is more than ten times higher than the leak rate for Xcel's pre-1970 coated steel inventory.[52] The study also noted that a number of other studies have shown a correlation between pipe material, "particularly cast iron and unprotected steel pipelines," and leak frequency.[53]

PHMSA also collects data from utilities regarding the causes of leaks on utilities' systems. A comparison of the causes of leaks by state also provides an interesting perspective on the risks posed by systems with inventories of differing pipe materials. For example, New Jersey had over 4,500 miles of cast iron mains remaining in its system at the end of 2015, which comprise over 13 percent of the mains in its system.[54] Corrosion accounted for nearly one-third of all leaks reported in 2015 in that state.[55] Massachusetts is another state with a high percentage of high-risk pipe material in its system, with cast iron mains accounting for over 15 percent of its system (3,315 miles) and bare steel mains comprising over 7 percent of its system (1,566 miles).[56] There, almost one-third of leaks are caused by corrosion.[57]

In contrast, equipment-related leaks are the main cause of leaks in Minnesota, where about 1 percent of its distribution system miles are cast iron or bare steel.[58] This type of leak is characterized by "malfunctions of control and relief equipment including regulators, valves, meters, compressors, or other instrumentation or functional equipment."[59] Corrosion is also a cause of leaks in Minnesota, with approximately 5 percent of leaks attributed to that cause.

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[52] Xcel's Supplemental Petition at Fig. 2.
[53] Gallagher, *supra* note 51, at 286–87.
[54] U.S. Pipeline & Hazardous Materials Safety Admin., *Cast and Wrought Iron Inventory*, https://opsweb.phmsa.dot.gov/pipeline_replacement/cast_iron_inventory.asp (last visited Feb. 9, 2017). New Jersey also had over 1,300 miles of bare steel in its system at the end of 2015. Appendix B.
[55] U.S. Pipeline & Hazardous Materials Safety Admin., *Gas Distribution Integrity Management Program: Performance Measure Reporting*, https://primis.phmsa.dot.gov/dimp/perfmeasures.htm (last visited Feb. 13, 2017) (click "Leaks/Incidents" hyperlink to access data portal) (*see* Appendix B).
[56] *Id.*
[57] *Id.*
[58] *Id.*
[59] U.S. Pipeline & Hazardous Materials Safety Admin., *Instructions (rev 5-2015) for completing Form PHMSA F 7100.1-1*, OMB No. 2137-0629 at 8.

Table 2, below, provides a summary of causes of leaks in the U.S. and the three above-mentioned states in 2005 and in 2015. Both New Jersey and Massachusetts have significantly reduced the percentages of leaks caused by corrosion in the spanning decade, which appears to have been driven by the significant pipeline replacement activity in those states. This type of information can help regulators better understand the risk profile of distribution systems across the state so that finite ratepayer resources can be efficiently allocated to address threats to the system.

Table 2. Causes of leaks by year in the U.S., New Jersey, Massachusetts, and Minnesota, comparison of 2005 to 2015.[60]

	U.S.		**NJ**		**MA**		**MN**	
	2005	2015	2005	2015	2005	2015	2005	2015
Corrosion	**139,236 (26%)**	**122,144 (23%)**	**7,842 (40%)**	**6,189 (32%)**	**6,739 (38%)**	**4,892 (29%)**	**489 (5%)**	**580 (6%)**
Nat. Force	27,177 (5%)	32,673 (6%)	3,164 (16%)	5,009 (26%)	4,889 (29%)	1,366 (8%)	627 (6%)	376 (4%)
Equip.	41,692 (8%)	152,171 (28%)	383 (2%)	2,860 (15%)	207 (1%)	2,604 (15%)	2,105 (21%)	6,315 (63%)
Mat./Weld	53,215 (10%)	53,740 (10%)	815 (4%)	894 (5%)	828 (5%)	1,312 (8%)	528 (5%)	563 (6%)
Excavation	118,843 (22%)	78,002 (15%)	2,533 (13%)	1,738 (9%)	1,442 (9%)	1,030 (6%)	1,763 (18%)	1,427 (14%)
Operations	7,536 (1%)	14,600 (3%)	202 (1%)	711 (4%)	49 (0%)	60 (0%)	37 (0%)	225 (2%)
Other Outside Force	10,560 (2%)	14,123 (3%)	353 (2%)	275 (1%)	81 (0%)	52 (0%)	117 (1%)	191 (2%)
Other Cause	117,967 (22%)	69,257 (13%)	1,978 (10%)	1,721 (9%)	4,132 (24%)	5,588 (33%)	733 (7%)	278 (3%)
Total	**516,226**	**536,710**	**17,270**	**19,397**	**18,007**	**16,904**	**6,399**	**9,955**

[60] U.S. Pipeline & Hazardous Materials Safety Admin., *Gas Distribution Integrity Management Program: Performance Measure Reporting*, https://primis.phmsa.dot.gov/dimp/perfmeasures.htm (last visited Feb. 13, 2017) (click "Leaks/Incidents" hyperlink to access data portal) (see Appendix B).

While cast iron and bare steel mains are, in some ways, the most problematic, other pipe materials can pose particular risks as well.

B. Other pipe material, particularly certain types of "legacy" material, pose risks to distribution systems as well.

Although removal of cast iron and bare steel pipe has been the primary focus of accelerated replacement efforts across the country, there are other pipe materials that have also been targeted for removal. For example, a report from the industry trade group the American Gas Foundation notes that unprotected coated steel and copper are also candidates for replacement as well as certain vintages of plastic, although the proportion of plastic pipe included in the replacement category "is believed to be a small proportion of the total."[61]

In particular, specific types and vintages of plastic pipe have also been a focus of safety regulators. A 1998 report from the National Transportation Safety Board that investigated the brittleness of certain vintages of plastic piping found that some characteristics of plastic pipe may have been "overstated" and that "any public safety threat posed by possible premature failure of plastic piping appears to be limited to locations where stress intensification exists."[62] The report recommended that gas system operators should gather data on plastic pipe in its system to "determine the extent of the possible hazard associated with their pipeline, including plastic piping."[63] In particular, the report singled out plastic pipe manufacturer called Century, which was involved in several pipe incidents, including one in Minnesota in 1983.[64] The Board determined that "plastic pipe extruded by [Century] . . . has poor resistance to brittle-like cracking under stress intensification" and recommended that "operators [should] develop a plan

[61] Yardley Associates, prepared for the Am. Gas Found., *Gas Distribution Infrastructure: Pipeline Replacement and Upgrades* 3 (2012).
[62] U.S. Dep't of Transportation, Nat'l Transportation Safety Board, *Special Investigation Report: Brittle-Like Cracking in Plastic Pipe for Gas Service* 28 (1998) (NTSB/SIR-98/01).
[63] *Id.*
[64] *Id.*

to closely monitor the performance of this piping and replace, in a timely manner, any of the piping that indicates poor performance."[65]

Xcel has also included certain segments of older, coated steel pipe for removal. The Company states that this type of pipe is riskier due to the mechanical couplings used to join the pipe.[66] This is an instance where the risk appears to arise not from characteristics of the pipe material itself, but rather due to instability in the joints caused by external forces, such as excavation or frost heave.[67] If left undisturbed, this type of pipe poses little to no risk.[68]

This section has taken a broad view of the federal pipeline safety requirements and the nationwide drive to remove certain leak-prone pipes from gas distribution systems. In general, there is a certain hierarchy to addressing risky pipe materials, which has been accelerated in certain parts of the country in recent years. The next section will describe the prevalence of leak-prone pipe in Minnesota as well as the efforts of Minnesota utilities to remove and replace this material.

IV. INTEGRITY MANAGEMENT EFFORTS AND PIPE INVENTORY OF MINNESOTA'S NATURAL GAS UTILITIES.

Natural gas distribution companies in Minnesota have also taken steps recently to accelerate replacement of aging infrastructure. The distribution systems owned by CenterPoint Energy and Xcel Energy appear to have the most leak-prone pipe material in the state, possibly due to the age of both systems. Table 3, below, provides an overview of the differences in the composition of Minnesota gas utilities' distribution systems, according to data reported by the utilities to PHMSA for the year 2015.

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[65] U.S. Dep't of Transportation, Nat'l Transportation Safety Board, *Special Investigation Report: Brittle-Like Cracking in Plastic Pipe for Gas Service* 29 (1998) (NTSB/SIR-98/01).
[66] Xcel's Initial Petition at Attachment C, p. 4.
[67] *Id.*
[68] *Id.*

Table 3. Miles of main by pipe material, regulated Minnesota natural gas LDCs, 2015.[69]

	Bare Steel		**Cast Iron**	**Coated Steel**		**Plastic**	**Miles Main**	**% Repl. Cand.**
	Unprotected	Protected		Unprotected.	Protected			
Xcel	**<1**	**--**	**--**	**185**	**785**	**8,125**	**9,157**	**2.0 %**
CNP	326	16	10	17	3,660	9,648	13,678	2.7 %
MERC	--	--	--	--	1,499	3,218	4,829	--
GPNG	--	--	--	--	119	340	459	--
GMG	--	--	--	--	13	751	763	--

The above snapshot of Minnesota utilities' distribution systems reflects years of concerted effort to remove the riskiest pipe material from its system. For Xcel, this effort pre-dates its GUIC rider requests and was a focus of testimony during its 2009 general rate case in Docket No. 09-1153. In that case, the Company noted that it had invested nearly $70 million in new or replacement gas distribution and transmission facilities in the two years since its prior rate case (2007 test year).[70] The Company also described its focus on replacing two pipe materials on its distribution system: replacement of over 100 miles of Century Plastic mains, which were the target of the 1998 NTSB bulletin described above, and a $3.5 million budget to continue replacement of cast iron in its system that was recovered in a separate rider and completed several years later.[71] In fact, Xcel has removed over 50 miles of cast iron main as well as over 30 miles of bare steel main in the years prior to its first GUIC rider request.[72]

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[69] U.S. Pipeline & Hazardous Materials Safety Admin., *Pipeline Mileage and Facilities*, http://phmsa.dot.gov/pipeline/library/data-stats/pipelinemileagefacilities (last visited Feb. 17, 2017). Xcel has approx. 60 miles of "other" pipe material that was included in the calculation of the total mileage. Replacement candidates included all bare steel, cast iron, and unprotected coated steel pipe materials divided by total miles of main.

[70] *In the Matter of the Application of Northern States power Company, a Minnesota Corporation, For Authority to Increase Rates for Natural Gas Utility Service in Minnesota*, MPUC Docket No. G002/GR-09-1153, Direct Testimony of William L. Kaphing at 9 (Nov. 12, 2009).

[71] *Id.* at 12.

[72] Xcel's Response to OAG Information Request No. 98 (Appendix A).

To date, Xcel is the only company to apply for special recovery of its related costs via the GUIC rider statute, but other Minnesota gas utilities are also in the midst of a massive capital spending campaign focused on projects similar to those pursued by Xcel for recovery via GUIC. According to testimony in its most recent rate case, CenterPoint Energy's integrity management costs were \$78.3 million and \$66.4 million in 2015 and 2016, respectively.[73] Its DIMP projects focused on removal of the following pipe materials: cast iron, bare steel, PVC, copper service lines, and vintage plastic.[74] Its integrity management projects "represent either a new set of activities . . . or an acceleration of work that occurs under normal System and Public Improvement projects."[75]

Great Plains is also undergoing replacement activities that it argues are driven by DIMP and TIMP requirements. It plans to replace all of its existing PVC main by spending \$2.5 million annually for at least the next decade.[76] In addition, the utility plans to replace all of its transmission infrastructure located within high consequence areas in 2016 at a cost of \$1.5 million. In direct testimony, its vice president of operations noted that "When you look at the flurry of activity in regards to regulatory initiatives recently, one can see this appears to be just the beginning."[77] While Great Plains has not yet filed an infrastructure rider under GUIC, it has

[73] *In the Matter of the Application of CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Minnesota Gas for Authority to Increase Rates for Natural Gas Utility Service in Minnesota*, MPUC Docket No. G-008/15-424, Direct Testimony of Talmadge R. Centers at 41 (Aug. 3, 2015).
[74] *Id.* at 14.
[75] *Id.* at 14–15 (Aug. 3, 2015) (defining normal system improvement projects as projects that "arise though the normal course of business" and public improvement projects as those that coincide with other public entities' infrastructure projects).
[76] *In the Matter of the Petition by Great Plains Natural Gas Co., a Division of MDU Resources Group, Inc., for Authority to Increase Natural Gas Rates in Minnesota*, MPUC Docket No. G-004/GR-15-879, Direct Testimony of Patrick C. Darras at 11 (Sep. 30, 2015).
[77] *Id.* at 13.

stated that it "will be addressing these investments with the Commission in an infrastructure rider to be filed in a separate docket in the near future."[78]

Minnesota Energy Resources Corporation, or MERC, has also discussed its capital investment plans in a recent rate case. There, the Company stated that it planned to invest almost $120 million in capital between 2015 and 2017.[79] Some of this capital spend is "required to maintain safe and reliable service."[80] MERC stated in briefing for that case that "the bulk of MERC's planned capital expenditures do not fit into a GUIC . . . rider."[81]

Across the state, Minnesota's gas utilities are spending over $100 million per year on integrity management projects and other related capital projects. The chosen methods of recovery differ, but it appears that many, if not all utilities are investing in infrastructure replacement projects at a clip that exceeds historical spending levels. Much more is known about Xcel's integrity management initiatives than other utilities' programs, but this does not mean that the investments made elsewhere in the state are any less significant.

This Background section places Xcel's GUIC activities into the broader context of activities that other states and other Minnesota utilities are undertaken as a result of recent federal safety regulations. It shows that, from state to state, the characteristics of the pipe inventories has a significant influence on the types of risks present in the distribution system. The methods of addressing these risks should be assessed appropriately given these

[78] Although Great Plains did note in its last rate case filing that it planned to file an infrastructure rider "in the near future." *In the Matter of the Petition by Great Plains Natural Gas Co., a Division of MDU Resources Group, Inc., for Authority to Increase Natural Gas Rates in Minnesota*, MPUC Docket No. G-004/GR-15-879, Direct Testimony of Nicole Kivisto at 7 (Sep. 30, 2015).

[79] *In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Utility Service in Minnesota*, MPUC Docket No. G-011/GR-15-736, Direct Testimony of Robert B. Hevert at 44 (Sep. 30, 2015).

[80] *Id.*

[81] *In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Utility Service in Minnesota*, MPUC Docket No. G-011/GR-15-736, MERC Initial Brief at 16 (Jun. 29, 2016).

characteristics—what works for one state, or even one utility, might not be appropriate elsewhere.

Compared to other states with a high proportion of cast iron and bare steel pipes in their system, Minnesota has relatively little of this high-risk pipe material. This fact is not meant to suggest that the threats Xcel is addressing on its system are not real or that its response to them is improper but, rather, that the Commission must have an objective method of understanding the impact of the GUIC-related work for which Xcel seeks rider recovery. There is a level of risk inherent in any distribution system and a level of removal of that risk that is appropriate for rider recovery. The next section contains analysis and recommendations regarding Xcel's 2017 GUIC rider, including specific concerns from its initial petition, its proposed performance metrics, and its proposed return on equity.

ANALYSIS AND RECOMMENDATIONS

This section will provide analysis of and recommendations on three topics: the Company's 2017 GUIC rider petition, its supplemental performance metrics filing, and its proposed return on equity. For ease of organization, each topic will feature analysis followed by a recommendation for the Commission. These recommendations are summarized below. The Commission should:

1. Establish a revenue cap of 6 percent to protect Xcel's ratepayers due to concerns regarding the Company's historical replacement rate in comparison to its GUIC replacement rate, mission creep, and confusing risk assessment methodologies;
2. Require the Company to file a more detailed cost and revenue study or initiate an investigation requiring the Company to demonstrate that its current rates are set at a just and reasonable level;

3. Decline, at this time, to adopt Xcel's proposed performance metrics, require the Company to file results from its AGA information request, and initiate a separate docket to begin a broader discussion on the development of performance metrics with Xcel, other gas utilities, and other interested parties; and
4. Find that the Company's proposed return on equity of 9.50 percent is not reasonable and should not be adopted in this docket. The Multi-Stage DCF analysis proposed in these Comments, using OECD growth data and a more appropriate proxy group, results in an ROE that is in the public interest. The Commission should thus set the ROE in this proceeding at 7.13 percent.

I. XCEL'S 2017 GUIC RIDER PETITION.

There are several elements of Xcel's 2017 GUIC rider petition that underscore a central concern in this docket, which is a lack of clarity regarding the scope of the risks Xcel faces on its system and the appropriateness and effectiveness of its programs designed to remove risk. This concern has manifested itself in three different ways, which will be described below. In response to these concerns, the Commission should take action to institute a revenue cap and to require additional, detailed information about costs and revenue in Xcel's next GUIC filing.

A. Xcel's 2017 GUIC Rider Petition has three significant shortcomings.

This section will highlight three areas of concern raised by the information provided by Xcel: the comparison of the Company's historical main replacement rate and the additional GUIC investments it seeks to recover, the overall growth of the GUIC Rider and the projects contained within it, and the Company's measurement of system risk.

1. A comparison of Xcel's historical main replacement rate raises concerns regarding costs associated with its GUIC projects.

Replacement of existing infrastructure is a regular component of any utility's capital spending. Xcel's infrastructure replacement activity is no different in this regard. It has been ongoing since well before it requested recovery via the GUIC statute. For example, in 2000, the Company replaced 13.1 miles of cast iron main, 1.4 miles of bare steel, 31.8 miles of coated steel, and 30.7 miles of plastic pipe.[82] In 2010, the test year of its most recent rate case, the Company replaced 53 miles of main.[83] Although these numbers represent pipe replaced for a variety of reasons other than integrity management, such as line relocations or abandonments, a certain level of revenue is being collected via the base rates established in the 2010 rate case to account for this "baseline" rate of replacement.

In order to be eligible for GUIC rider recovery, costs incurred in a gas utility projects that "are in service but were not included in the gas utility's rate base in its most recent general rate case."[84] The underlying principle of accelerated main replacement recovery policy is that rider recovery is only appropriate for the incremental costs incurred because of the accelerated replacement activity. In other words, the base rates established in a utility's most recent rate case proceeding reflect a baseline level of pipe replacement activity. Figure 3, below, illustrates the miles of pipe Xcel replaced in each of the years 2010 through 2016, with three- and five-year rolling averages. In comparing 2010 (the rate case test year) with 2015 and 2016 (the first two years of GUIC-recoverable projects) it is clear that the Company has a significant historical replacement rate.

[82] Xcel's Response to OAG Information Request No. 98 (Appendix A).
[83] *Id.*
[84] Minn. Stat. § 216B.1635 subd.(1)(b)(2) (2016).

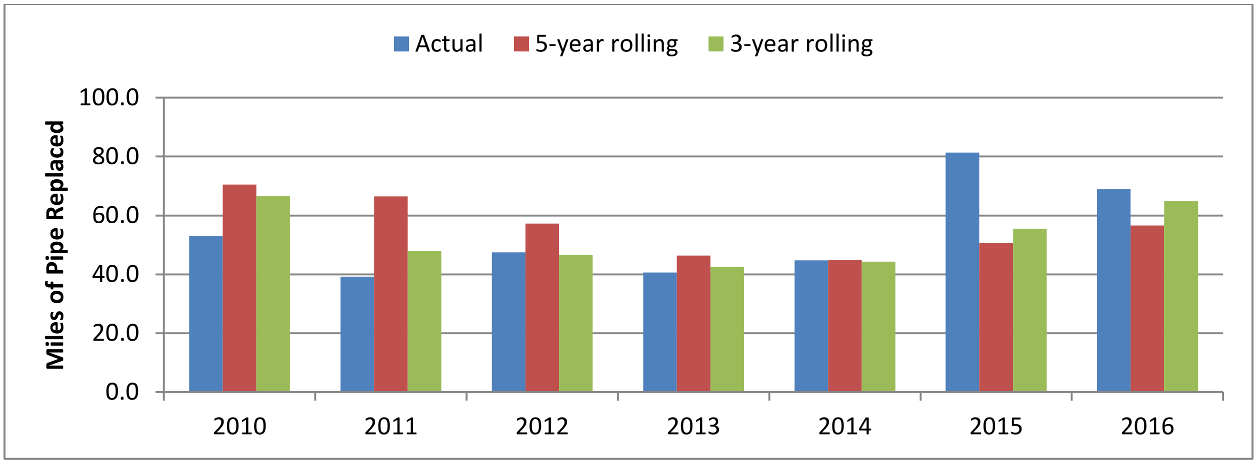

Figure 3. Actual miles of pipeline replaced in Xcel's distribution system compared to 5- and 3-year rolling averages, from 2010 to 2016.[85]

Care should be taken in reading too much into the above figure, as many factors influence replacement projects as well as the accounting of plant additions, retirements, and remaining lives that are built into rate base and thus base rates in each rate case. But it is a useful exercise nonetheless because it puts into context the impacts that PHMSA's rulemaking and its *Call to Action* have had, or not had, on the replacement rate of Xcel's distribution pipe. It also highlights that the longer Xcel goes without a general rate case, the more difficult it becomes to understand how the level of replacement activity that is already recovered via base rates established in the 2010 rate case compares to the accelerated level of replacement that Xcel is now recovering via the GUIC rider.

Other jurisdictions have instituted methods to ensure that infrastructure riders do not collect revenue that is already incorporated into base rates. For example, Massachusetts requires an reduction to rider-related depreciation expense by the book depreciation associated with the plant it retires during the applicable rider period.[86] However it is accomplished, it is critical for

[85] Data from Xcel's Response to OAG Information Request No. 98 (Appendix A).

[86] *Petition of Boston Gas Company and Colonial Gas Company, each doing business as National Grid, for Approval of 2015 Gas System Enhancement Plan, pursuant to G.L. c. 164, § 145, for rates effective May 1, 2015*, D.P.U. Docket No. 14-132, Order at 64 (Apr. 30, 2015).

the Commission to be able to delineate a bright line between what is already being recovered and what is completely incremental to ensure that ratepayers are not paying for the same investment twice. This concern grows with each passing year as ratepayers are asked to pay more GUIC-related costs and the scope of the GUIC projects continues to evolve.

2. The growing size of GUIC projects and its impact on ratepayers.

The impact of GUIC, whether measured by customer bill impacts, capital budget, or the scope of its projects, continues to grow. The OAG asked the Company to provide an estimate of the bill impact to a typical customer, by rate class. In 2017, the typical residential customer's bill impact will be $23 per year; in 2021 the impact will double, to $49 per year.[87] Looking forward to 2018, the Company's capital expenditure on GUIC projects is expected to more than double, from the projected 2017 level of $23.4 million (79 percent of 2010 capital expenditures) to $45.7 million in 2018 (*153 percent* of 2010 capital expenditures).[88] The 2018 level of capital expenditures is expected to stay at or slightly above that level for the duration of the years provided by the Company, to 2021.[89]

The open-ended nature of the GUIC statute with respect to which projects are eligible contrasts with other states' statutes[90] and presents a greater risk to ratepayers that the Company will request an ever-expanding roster of projects for special recovery. This concern may also be a function of the current inventory of pipes present in Xcel's distribution system, described

[87] Xcel's Response to OAG Information Request No. 97 (Appendix A). The Company's use of actual sales data through September 2016 is understandable, but makes comparison to the forecasted sales data and, thus, the bill impacts, difficult, especially for 2015 and 2016 data.
[88] Xcel's Initial Petition at Attachment L.
[89] *Id.* 2021 is the latest year provided by the Company, but there is no indication that its GUIC-related capital spending will end after that year.
[90] *Compare* Mass. Gen. Laws ch. 164, § 145 (requiring replacement plans to include replacement of certain pipe materials (non-protected coated steel, cast iron, and wrought iron) including an anticipated timeline reflective of the accelerated nature of the pipe removal) *with* Minn. Stat. § 216B.1635 (defining eligible projects to include "replacement or modification of existing natural gas facilities, including surveys, assessments, reassessment, and other work necessary to determine the need for replacement or modification of existing infrastructure").

above, which no longer includes the highest-risk cast iron and bare steel pipes, but rather a collection of vintage plastic and coated steel pipes. In other words, Xcel is addressing a number of disparate risks on its system via GUIC, whereas other programs in other jurisdictions are focused on the replacement of certain materials of main.[91] In those states, the utility has a finite amount of replacement candidate pipe in its system as well as a historical replacement rate of that pipe. Using those two amounts, simple math determines how many years it would take to replace all of the risky pipe in the system.[92] Once this "business as usual" timeline has been established, the respective commission can determine whether the pipe should be replaced at a quicker rate and what that replacement rate (and the associated costs) should be. Due to the nature of the projects under Xcel's umbrella of GUIC projects, this math becomes trickier.

A more concrete example of this concern is Xcel's recovery of costs associated with the replacement of distribution valves, a DIMP project. On page 30 of its Initial Petition, the Company projects that it will spend nearly $1 million in "to replace existing distribution system isolation valves which have outlived their useful lifespan." When asked by the OAG whether the Company would have replaced these valves in the absence of DIMP, the Company responded that it would have, but that DIMP's requirement to "assess and improve the safety, reliability, and integrity of our natural gas infrastructure" has resulted in a "pace and magnitude" of replacement efforts that has "outstripped" prior replacement efforts.[93] The Company provided no information on what the historical, baseline replacement level and spending was for this type

[91] For example, other jurisdictions infrastructure-related rider programs are specifically titled such that main replacement is the only purpose for activity in the rider. CenterPoint Energy's Arkansas utility has a Main Replacement Program rider "to support the expedited replacement of cast-iron mains, bare steel mains, [unprotected steel mains], pre-1984 plastic mains . . . and associated services." CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Arkansas Gas, Tariff Part IV, Rider Schedule No. 2 at 2.1.

[92] For example, if a utility had 100 miles of replacement candidate pipe in its system and a 10 mile per year baseline, historical replacement rate, it would take that utility 10 years to remove all of that pipe under normal, non-accelerated conditions.

[93] Xcel's Response to OAG Information Request No. 45 (Appendix A).

of equipment, nor did it point to a specific requirement in the DIMP regulations that required accelerated replacement of these valves. The DIMP regulations, as noted above, do not establish prescriptive requirements for pipeline operators, but rather encourage a thorough process by which threats are identified and addressed. DIMP does not fully explain the replacement, accelerated or otherwise, of distribution valves that have become obsolete on their own. The Company has not provided sufficient detail to demonstrate both that it is only seeking recovery for incremental, accelerated replacement of distribution valves, nor that the rate of acceleration is reasonable. This is just one example of the Company pointing to newly-established pipeline safety regulations without providing the full context of its safety practices (and spending) prior to TIMP and DIMP.

In the absence of a clear picture of the "before" and "after" of Xcel's integrity management practices at issue here, one avenue that could provide much-needed clarity is the Company's approach to assessing and removing risk from its system. If the Company can identify an objective method to quantify the risk on its system and the annual rate of removal of risk from its integrity management programs, then regulators can engage in the discussion of the appropriate level of cost recovery to allow via the GUIC rider. Unfortunately, this docket lacks such clarity. The next section will discuss how the Company's methodologies and results are opaque and do not allow outside parties to develop an objective understanding of the risks present in Xcel's system in a given year or over time.

3. The Company's risk assessment methodology does not allow for a meaningful comparison across projects or a determination of overall risk removed by GUIC projects.

One of the central objectives of the Company's GUIC projects is to remove risk from its distribution system. The Company's ratepayers have funded these projects through the GUIC rider, but there are still significant unanswered questions about the work performed to date:

- How much quantifiable risk has been removed from the system via GUIC projects?
- What level of risk represents an acceptable level to the Company, the Commission, and to ratepayers?
- Is the Company achieving an acceptable level of risk in a cost effective manner?
- What is an appropriate rate of risk removal (and at what cost) to be recovered under GUIC?

Some of these answers must come from the Commission, but it can only begin consideration after the Company provides it with a quantifiable, verifiable, and repeatable method to quantify system risk. In this year's petition, the Company provided risk assessment data for its TIMP and DIMP projects,[94] but these documents raised more questions than they answered.

Xcel utilizes risk modeling software to "evaluate relative risk based on variables" and a calculated relative risk value is assigned and used as guidance for projects.[95] As an example, the risk summary for its largest DIMP project, Poor Performing Mains and Services, provides relative risk rankings for coated steel and Aldyl-A plastic.[96] The "Optimain Score" for potential coated steel projects ranges from 55 to 786, and all 14 proposed projects are deemed "high" based on the Company's rubric.[97] The "QRA Score" for Aldyl A projects range from 4.500 to 7.125 and fall into the "high" or "medium" priority ranges.[98] The Company did not describe the process behind how the assessed projects were chosen, why they were scored using two different methods, or how the high-medium-low categories were developed. All that is known is that the Company has identified a roster of projects to recover via GUIC in a particular year, presumably to fit the capital budget it has set; it has assessed these projects under inconsistent methods and

[94] Xcel's Initial 2017 Petition at Attachments B2 and C2(a).
[95] *Id.* at Attachment C, p. 2.
[96] *Id.*at Attachment C2(b).
[97] A high priority project has a score greater than 36. *Id.*
[98] Four Aldyl-A projects are "high" while six projects are "medium" under the Company's rubric. *Id.*

scoring rubrics; and it has determined that all of the assessed projects present a level of risk that is appropriate to recover via its GUIC rider. It is impossible to know, based on this limited sample of risk scores, whether the Company is prudently selecting the highest-risk candidates for removal. And an answer to this inquiry is impossible without a broader understanding of the risk present in Xcel's distribution system.

The concerns regarding the risk assessment methodology also raise questions regarding the levels of spending on the projects from year to year. For example, it is unclear why $11.03 million is a reasonable amount of capital spending to reduce the risks presented by the 2017 Poor Performing Mains and Services project, just as it was unclear why $6.88 million was the appropriate amount to spend on this project last year.[99] Was the same level of risk removed in both years? If so, was it because the costs doubled or was it because the required number of miles replaced doubled? And if the number of miles increased, does that imply that the pipes removed in 2017 will be, on average, less risky than the pipes removed in 2016?

Although these important questions remain unanswered, the Company has planned to grow its GUIC-related spending in the coming years. There are important steps the Commission should take now to ensure the protection of ratepayers today and in the future.

B. The Commission should institute a revenue cap on Xcel's GUIC recovery and require it to file more detailed financial information in its next GUIC Rider petition.

Uncertainty regarding the historical replacement rate versus the GUIC replacement rate, the growing size and scope of GUIC, and the lack of clarity regarding the risk assessment methods employed by the Company lead to two recommendations. First, the institution of a

[99] *In the Matter of the Petition of Northern States Power Company for Approval of a 2016 Gas Utility Infrastructure Cost Rider*, MPUC Docket No. G-002/15-808, Comments of the Office of the Attorney General at 11 (Mar. 17, 2016).

revenue cap would protect Xcel's ratepayers from excessive growth of the amount requested for recovery via the GUIC rider while also allowing the Company to reduce its financial risk of cost recovery. Second, more detailed cost and revenue information, would allow regulators to better understand the financial condition of the utility as well as the impact of the GUIC rider on the base rates set in its most recent rate case.

1. The Commission should implement a revenue cap of 6 percent for GUIC recovery to protect ratepayers.

A cap on the amount of recovery allowed in a cost recovery rider is a common ratepayer protection that balances the needs of the utility and its ratepayers. Such a cap recognizes the interests of the utility in the expedited cost recovery of unexpected, but important costs it has incurred while also protecting its ratepayers from being responsible for cost overruns or otherwise imprudent costs. Xcel's gas ratepayers are now nearly a decade removed from the Company's most recent rate case. 2017 GUIC capital spending is close to its 2010 test year capital expenditure (in both prior years and in the years forward, GUIC capital spending exceeds the test year expenditure).[100] 2017 GUIC revenue requirements continue to increase, as does the impact on typical ratepayers.[101]

The Commission has previously cautioned that special cost recovery mechanisms can erode a utility's incentives for cost control in certain situations and that their presence can obscure the actual rate impact felt by ratepayers in the utility's next rate case.[102] In addition, riders can shift the risk faced by the utility from shareholders to ratepayers.[103] One concrete tool at the Commission's disposal is a revenue cap, which would limit the risk borne by ratepayers.

[100] Xcel's Initial Petition at Attachment L.
[101] *See* Xcel's Response to OAG Information Request No. 97 (Appendix A).
[102] Minnesota Public Util. Comm'n, *Report to the Legislature: Utility Rates Study as Required by Laws of Minnesota, 2009, Chapter 110*, at 8 (Jun. 2010).
[103] *Id.* at 12.

Such a cap would limit the allowable rider recovery, but not the utility's ability to spend money to address system safety—Xcel would be able to spend money for GUIC projects in excess of the revenue cap and could ask for recovery as appropriate in its next rate case.

In last year's GUIC rider docket, the OAG advocated for a 6 percent cap on revenue as compared to base rates due to concerns regarding the growing amount of revenue that is being collected via this particular mechanism.[104] This size cap continues to be a reasonable for the Company. Further, as the amount of revenue collected from ratepayers under the GUIC rider continues to grow, so does the importance of implementing a cap on revenue. Xcel recovers approximately $159 million in base revenue per year.[105] Its requested revenue related to 2017 GUIC rider is approximately $22 million, which is approximately 14 percent of its annual base revenue.[106] A 6 percent cap would limit the amount of revenue the Company could collect via the GUIC cost recovery rider to approximately $9.5 million.

Caps on the amount of revenue that is recoverable in infrastructure riders are common throughout the country. Xcel included in its initial filing a summary produced by the American Gas Association of infrastructure-related cost recovery mechanisms across the country.[107] That document describes cost recovery mechanisms that are capped in Kansas (10 percent of base revenue), Massachusetts (3.75 percent of distribution revenues), and Pennsylvania (7.5 percent of billed revenues).

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[104] *In the Matter of the Petition of Northern States Power Company for Approval of a 2016 Gas Utility Infrastructure Cost Rider*, MPUC Docket No. G-002/15-808, Comments of the Office of the Attorney General at 16–24 (Mar. 17, 2016).
[105] Xcel's Initial Petition at Attachment L.
[106] $22 million / $159 million = 13.84 percent. There is a discrepancy between this percentage and the percentage of *revenue collected* in 2017 in Attachment L due to the difference in the year the revenue is required and an overlap in calendar years with when the revenue will be collected from ratepayers. A cap would not affect recovery of deferred costs already approved for recovery in the GUIC rider.
[107] Xcel's Initial Petition at Attachment S.

Another option, which could be implemented in addition to or independent of a revenue cap, is requirement for a more thorough cost and revenue study to be filed with the Company's next GUIC petition. The next section will discuss this option.

2. More detailed information regarding utility costs and revenue is needed to allay concerns about over-earning.

In the last GUIC docket, due to concerns expressed by the OAG and Commission staff regarding the potential for over-earning, the Commission ordered the Company to file a cost and revenue study to reconcile calendar year 2015 GUIC activities with base rates, its PGA, and its Jurisdictional Annual Report.[108] In this year's GUIC rider petition, the Company filed a one-page reconciliation, as required, but did not provide additional work papers or a narrative explanation of the results.[109]

It does not appear that the information provided by the Company in Attachment J is responsive to the specific questions raised by Commission staff in last year's briefing papers.[110] More detail is needed. To answer the question of what additional detail may be appropriate, the Commission should look to the Federal Energy Regulatory Commission ("FERC") for guidance regarding cost and revenue studies that interstate pipeline companies must file. In *Bear Creek Storage Co., LLC*, FERC ordered a small storage company that had established its rates 22 years prior to file a full cost and revenue study to determine whether its current rates were just and reasonable.[111] In a subsequent order, following the Company's request for rehearing, FERC

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[108] *In the Matter of the Petition of Northern States Power Company for Approval of a 2016 Gas Utility Infrastructure Cost Rider*, MPUC Docket No. G-002/15-808, Order at 9 (Aug. 18, 2016).
[109] Xcel's Initial Petition at Attachment J.
[110] *See In the Matter of the Petition of Northern States Power Company for Approval of a 2016 Gas Utility Infrastructure Cost Rider*, MPUC Docket No. G-002/15-808, Staff Briefing Papers at 43 (Jul. 7, 2016) (specifying four results from staff's analysis that staff "cannot explain" for which additional information from the Company "may be needed" to determine whether the Company is over-earning).
[111] Bear Creek Storage Co., Order Instituting Investigation and Setting Matter for Hearing Pursuant to Section Five of the Natural Gas Act, 137 F.E.R.C. ¶ 61,134 (Nov. 17, 2011).

clarified that the Company would be required to file a comprehensive cost and revenue study pursuant to FERC rules regarding material required to be filed for rate changes.[112]

In 2015, FERC issued a Policy Statement titled, "Cost Recovery Mechanisms for Modernization of Natural Gas Facilities," which was an acknowledgment of recent "governmental safety and environmental initiatives" that indicated a future increase in pipeline spending to increase safety and reliability.[113] The Statement established five standards to be met in order to approve a cost-recovery mechanism.[114] The first standard requires a review of existing rates, either through a recent rate case or "through a collaborative effort between the pipeline and its customers."[115] Although FERC later clarified that this "collaborative effort" did not necessarily equate to a full cost and revenue study, "a pipeline seeking a modernization cost surcharge must demonstrate to the Commission that its existing base rates are no higher than a just and reasonable level."[116]

The Commission is under no obligation to adopt FERC standards, but it would be a mistake to discard the outcomes of the deliberative process undertaken by FERC in very similar circumstances to the issues the Commission is considering here. Xcel's one-page Attachment J does not demonstrate that it is *not* over-earning, nor does it appear to address the specific questions Commission staff had in last year's docket. It does make clear, however, that the

[112] Bear Creek Storage Co., Order Denying Rehearing, 138 F.E.R.C. ¶ 61,019, 61,052–53 (finding that the additional filing requirements found in 18 C.F.R. § 154.312 are necessary to determine whether the Company's current rates are just and reasonable).
[113] Policy Statement on Cost Recovery for Modernization of Natural Gas Facilities, 151 F.E.R.C. ¶ 61,047, para. 1 (Apr. 16, 2015). OAG Comments in 15-808 provide additional information regarding the Policy Statement. *In the Matter of the Petition of Northern States Power Company for Approval of a 2016 Gas Utility Infrastructure Cost Rider*, MPUC Docket No. G-002/15-808, Comments of the Office of the Attorney General at 23–24 (Mar. 17, 2016).
[114] Policy Statement on Cost Recovery for Modernization of Natural Gas Facilities, 151 F.E.R.C. ¶ 61,047, para. 20 (Apr. 16, 2015).
[115] *Id.*
[116] Order Denying Request for Clarification, 152 F.E.R.C. ¶ 61,046, para. 15 (Jul. 16, 2015).

requirement imposed on Xcel in the previous docket is not sufficient to remedy these serious concerns. The Commission should thus consider requiring Xcel to file a cost and revenue study containing information sufficient to demonstrate that it is not currently over-earning. For example, the cost and revenue study could encompass information required to be filed as part of the utility's notice of a change in rates.[117]

The concerns raised in this section and the recommendations that follow, are all related to a persistent, central concern in this docket: that other parties do not currently have the ability to conduct an objective review of Xcel's integrity management efforts to determine reasonableness and prudency under the GUIC statute. It is thus important to limit the size of this recovery via a revenue cap and to require additional information about costs and revenues in the next filing. It is also important to initiate a deliberate, thorough process under which Xcel's and other utilities' integrity management programs can be assessed from year to year. This process should result in the development and implementation of performance metrics that are objective, easily measured, and that are a reliable indicator of success toward Commission-established integrity management objectives. The next section will describe the first step taken in this process by Xcel in this year's docket, why that step falls short, and why the Commission should instead initiate a separate process to develop integrity management performance metrics for all gas utilities in the state.

[117] Minn. R. § 7825.3800.

II. XCEL'S PROPOSED METRICS.

A central theme of OAG comments from Xcel's 2016 GUIC petition was the need to establish performance metrics by hiring an independent expert or, in the alternative, to direct the Company to develop metrics with "meaningful stakeholder involvement" while also keeping in mind that neither the OAG nor other parties "employ the technical or engineering staff that would be essential to evaluate any metrics or goals that are developed."[118] In its August 18, 2016 Order, the Commission ordered the following:

> Xcel shall develop metrics to measure the appropriateness of GUIC expenditures, to be included in future GUIC Rider filings, and to provide stakeholders the opportunity for meaningful involvement. Each metric should include a reconciliation to the pertinent TIMP/DIMP rules, and/or if not tied to TIMP/DIMP requirement, the Company must identify what goal, benefit, and/or requirement it addresses.[119]

Xcel held a stakeholder meeting in November of 2016 to present the metrics it formally presented in its January 13, 2017 supplemental filing.[120] In December, the OAG emailed informal comments to Xcel representatives with feedback on the proposed metrics.[121] This communication stressed the concerns of the OAG regarding need for metrics that allow the Commission to determine the "appropriate amount of risk that is removed each year by GUIC projects."[122] Later, in January, the OAG provided input on a draft of the AGA survey on

[118] *In the Matter of the Petition of Northern States Power Company for Approval of a 2016 Gas Utility Infrastructure Cost Rider*, Comments of the Office of the Attorney General at 9–16 (Mar. 17, 2016).
[119] *In the Matter of the Petition of Northern States Power Company for Approval of a 2016 Gas Utility Infrastructure Cost Rider*, Order Requiring Updated Report, Approving Rider Recovery, and Requiring Metrics to Evaluate GUIC Expenditures at 8 (Aug. 18, 2016).
[120] A copy of the Xcel slide deck presented at the Nov. 16, 2016 stakeholder meeting was attached to its Jan. 13, 2017 supplemental petition.
[121] E-mail from Joseph Dammel, Assistant Attorney Gen., to Amy Liberkowski, Director, Regulatory Pricing and Analysis, Xcel Energy (Dec. 14, 2016, 11:36 AM CST) (attached as Appendix C).
[122] *Id.*

performance metrics that Xcel was preparing to distribute to other utilities across the country.[123] It is unknown whether the Company incorporated any of the edits to the AGA survey that were suggested by the OAG. The OAG requested the final version of the AGA SOS, but was told only that the Company had submitted proposed survey questions to the AGA, with no detail regarding the incorporation of the proposed OAG edits.[124] On January 13, 2017, Xcel filed the metrics it had proposed two months earlier, with no apparent changes.

The Company proposed five metrics: three related to DIMP programs and two related to TIMP. The DIMP-related metrics are leak rate by vintage and pipe type; Poor Performing Main Replacement project unit cost; and Poor Performing Service Replacements unit costs.[125] The TIMP-related metrics are gas transmission anomalies repaired and actual versus estimated cost variances for transmission capital projects.[126] These metrics will be discussed individually below, but it is important to first review the concepts that led to the call for metrics in last year's docket.

A. OAG Comments in 15-808 focused on establishment of objectives and a process to develop performance metrics and are still relevant in this docket.

The overriding concern with Xcel's GUIC projects, now three years into its GUIC rider, is that it is still impossible to determine what the proper size of the infrastructure investments should be in order to balance the dual public interests of safety and cost-effectiveness. As the OAG stated in last year's docket, "[T]he Commission cannot assess whether the money spent was reasonable and prudent until they know and understand the level of risk reduction the

[123] A redlined version of the draft AGA survey containing the edits proposed by the OAG are included in Appendix D.
[124] Xcel Energy response to OAG Information Request No. 47 (attached in Appendix A).
[125] Xcel's Supplemental Petition at 5.
[126] *Id.*

investment is trying to achieve."[127] In other words, the Commission has information about the costs incurred by the Company, but little ability to ascertain the effectiveness of the costs.

In last year's GUIC docket, the OAG expressed concern over how to properly measure the effectiveness of projects recovered via Xcel's GUIC rider.[128] The relevant comments centered upon the "particularly challenging" task of determining whether GUIC investments are reasonable and prudent.[129] This challenge requires more than an analysis of whether the Company met its capital budget or had cost oversight committees and instead focuses on whether the level of safety investments is adequate in order to meet the relevant state and federal pipeline safety requirements. This focus is important because of the considerable discretion that utilities have in satisfying safety requirements and in deciding how much to spend on the investments.[130]

Last year, the OAG presented two broad questions to help guide the Commission in establishing objectives and goals that could lead to effective performance metrics:

1. How to measure the risk in the system and where to define the level of acceptable risk; and

2. How to track the removal of risk and the overall performance of the GUIC-related projects in achieving this removal.[131]

The first question acknowledges that, at any one time, a distribution system has a particular level of risk. The acceleration of replacement efforts across the country and PHMSA's

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[127] *In the Matter of the Petition of Northern States Power Company for Approval of a 2016 Gas Utility Infrastructure Cost Rider*, MPUC Docket No. G002/M-15-808, Comments of the Office of the Attorney General at 11 (Mar. 17, 2016).
[128] *In the Matter of the Petition of Northern States Power Company for Approval of a 2016 Gas Utility Infrastructure Cost Rider*, MPUC Docket No. G002/M-15-808, Comments of the Office of the Attorney General at 9–16 (Mar. 17, 2016).
[129] *In the Matter of the Petition of Northern States Power Company for Approval of a 2016 Gas Utility Infrastructure Cost Rider*, MPUC Docket No. G002/M-15-808, Comments of the Office of the Attorney General at 10 (Mar. 17, 2016).
[130] Ken Costello, The Nat'l Regulatory Research Institute, *Balancing Natural Gas Pipeline Safety with Economic Goals* 12 (May 2012).
[131] *Id.* at 14.

2011 *Call to Action* reflect the perception in some states that the then-current replacement efforts were not proceeding at a quick enough pace to reduce system risk. Since a system with no risk is both practically and financially impossible, it is the job of state commissions to determine the level of risk currently in the system, what amount of risk has been historically removed from the system each year, and what the appropriate amount of accelerated removal, if any, is in the public interest. Once that is defined, the state regulator can then balance the need to reduce risk at an accelerated pace, if necessary, to meet pipeline safety requirements with the need to ensure that its ratepayers are not on the hook for unnecessary and imprudent investments in the system.

The second question that was introduced last year would help to guide the Commission in its oversight from year-to-year to ensure that system risk is being reduced each year in a cost-effective manner. This query also supports the establishment of an objective goal. For example, properly-designed performance metrics should be reliable, repeatable, consistent, and comparable, among other attributes.[132] Properly-designed metrics should track objective progress toward an objective goal. For example, if a metric was developed that assigned a system risk score, and that score indicated an elevated system risk, then the Commission could work toward establishing a target score for the system and then work to determine the annual cost to achieve the target score. Similarly, if the Commission chose to design a metric involving leaks, then it would expect to see an annual reduction in leaks toward some established goal.

Last year's comments drew upon the work of Ken Costello, who authored a 2012 report by the National Regulatory Research Institute ("NRRI"), the research arm of the National Association of Regulatory Utility Commissioners ("NARUC").[133] Mr. Costello stated that,

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[132] U.S. Dep't of Transportation, Pipeline & Hazardous Materials Safety Admin., *Pipeline Safety: Guidance for Strengthening Pipeline Safety through Rigorous Program Evaluation and Meaningful Metrics* 8 (2014).
[133] Costello, *supra* note 130.

"State utility regulators are in the best position to balance safety and ratemaking goals, frequently confronting them with a difficult challenge."[134] In addition, he stated that "Commissions must not only judge the justification for these costs in improving safety but also assess whether the underlying actions are least cost."[135] The underlying message of this report is that achieving a safe distribution system and compliance with state and federal laws requires a nuanced balancing of interests that recognizes the utility's considerable "discretion on how to satisfy those [safety] regulations and how much money to spend."[136] A review of this nature requires that the Commission have enough information and the tools necessary to both measure the effectiveness of safety investments, and determine whether they are least cost.

Importantly, Mr. Costello highlights the importance of allowing for flexibility to achieve safety goals set by the regulator, a step that has not yet been explicitly taken by the Commission in the GUIC proceedings to date because the Commission has not yet established specific objectives to guide gas utilities' compliance actions for safety.[137] The Commission should set a target and allow utilities to demonstrate that it is meeting the target in a cost-effective manner. Although this step is not a straightforward process, it is critical to ensure that subsequent metrics are appropriate and effective.

In last year's docket, the Commission chose to let Xcel develop and propose the metrics under which it desired to be regulated. The resulting metrics proposal, which will be discussed in the next section, contains metrics that may be appropriate, but which are not based on any Commission-identified objectives and thus cannot be fully analyzed at this time.

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[134] *Id.* at iv.
[135] *Id.*
[136] *Id.* at 12.
[137] *Id.* at 15.

B. Xcel's proposed metrics cannot be fully assessed in this docket and should not be implemented at this time.

The five metrics proposed by Xcel are designed around the Company's objective to "reduce the likelihood of a significant gas incident that may result in injury to the public or damage to property."[138] In addition, the Company set an objective to achieve a "continuous reduction in leaks and ruptures."[139] Such an objective is open-ended and ill-defined. For these reasons, and because the Commission and not the Company should be the entity driving development of metrics, the Commission should decline at this time to adopt the metrics proposed by Xcel. A brief analysis of each proposed metric will show, in the alternative, that even if the Commission desires to allow the Company to define its own objectives and design its own metrics, that the metrics proposed by Xcel should not be adopted at this time.

1. The DIMP leak rate metric may provide useful information, but only after further development.

The problem created by a performance metric rooted in an open-ended objective is that the resulting metric serves no useful purpose. For example, the Company's proposed DIMP metric measuring leak rate by vintage and pipe type may be a useful metric if the Commission finds that business-as-usual replacement rates would result in a leak rate that is higher than acceptable. In such a case, a metric could be established that ties replacement spending to a reduction in material-specific leak rates. This would encourage the removal of the riskiest pipes in the system toward a specified leak rate goal.

The Company did not state its target leak rate for coated steel mains in its filed materials. In a response to an OAG information request, however, it stated "leak rates for pre-1970s coated steel will continue to decrease to similar levels as other modern materials (plastic and steel) in

[138] Xcel's Supplemental Petition at 4.
[139] *Id.*

the system."[140] In other words, by replacing the leakiest pipe first, the leak rate of older pipes will someday converge to something close to modern day leak rates. Currently, as seen in Figure 2 of Xcel's supplemental petition, leak rates for pre-1970 coated steel mains range from approximately 0.3 leaks-per-mile to 0.1 leaks-per-mile, while post-1970 coated steel mains have leak rates between 0.1 leaks-per-mile and 0.05 leaks-per-mile. Clearly the newer coated steel mains have a lower leak rate, which should be reflective of a lower risk to the system, but it is unclear that special cost recovery is justified to drive down the pre-1970 leak rates in an accelerated manner.

It is important to consider the risks posed by coated steel compared to other pipe materials such as cast iron or bare steel when assessing the likelihood and consequence factors of risk.[141] The Company itself acknowledged that many coated steel mains "appear to pose no risk unless they have been disturbed through third-party damage (excavation hits) or natural forces (frost heave)."[142] One solution, which the Company has adopted, is to remove a significant quantity of coated steel pipes "to reduce operating risk and reduce the likelihood of incidents."[143] But another solution would focus on reducing the rate of excavation damage to its system, which is a leading cause of leaks reported by gas distribution operators in Minnesota.[144] Again, Xcel's solution may be the most sound, but information is not available to assess whether that is the case.

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[140] Xcel Response to OAG Information Request No. 41 (attached in Appendix A).

[141] Xcel's Response to OAG Information Request No. 36 ("Although the metrics proposed to not have a direct numerical alignment with safety and reliability, they do have a correlation with the likelihood and consequence factors of risk.") (attached in Appendix A).

[142] Xcel's Initial Petition at Attachment C, p. 4.

[143] *Id.*

[144] *See* Appendix B. The leading cause of leaks in Minnesota in 2015 is equipment failure which is "a leak caused by malfunctions of control and relief equipment including regulators, valves, meters, compressors, or other instrumentation or functional equipment." U.S. Dep't of Transportation, Pipeline & Hazardous Materials Safety Admin., *Instructions (rev 5-2015) for completing Form PHMSA F 7100.1-1* at 8.

In contrast, as discussed above, PHMSA's 2011 *Call to Action* focused on "cast iron mains, certain vintages of plastic pipe and mechanical coupling installations, bare steel pipe without adequate corrosion control, and copper piping."[145] According to the most recent data available from PHMSA, which is summarized in Appendix B, Xcel has less than one mile of unprotected bare steel mains remaining it its system. There are approximately 4,000 unprotected bare steel (42) and unprotected coated steel (3,857) services remaining in its distribution system at the end of 2015, but the Company has no cast iron mains or services in its system.[146] According to PHMSA data, Xcel removed all of its cast iron main and a substantial portion of its bare steel main in 2012, prior to its GUIC rider recovery petition.[147]

This discussion is not an argument against Xcel's decision to focus on replacement of its unprotected coated steel mains or portions of its vintage plastic inventory. As stated in prior dockets, neither the OAG nor the Commission is in a position to assess the engineering merits of the risks posed by these pipe materials, which appear to be, by their nature, riskier than modern pipe materials, but less risky than cast iron or bare steel. The issue is where to draw the line for the extraordinary method of recovery requested by the Company through GUIC.

Simply tracking the leak rate of a particular pipe material over time, as Xcel proposes to do here, does not provide any valuable information relevant to this most important concern. As Xcel itself states, its goal is to reduce the leak rate for coated steel such that its pre-1970 inventory has the same leak rate as its post-1970 inventory, which can only be accomplished by removal and replacement of all but the least risky pipes in its system. Xcel plans to spend over

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[145] U.S. Dep't of Transportation, Pipeline & Hazardous Materials Safety Admin., *White Paper on State Pipeline Infrastructure Replacement Programs* 1 (Dec. 2011) (included as an attachment to PHMSA's *Call to Action*).
[146] Appendix B.
[147] *Id.*

$50 million on this project alone in the next five years,[148] the costs of which ratepayers will be asked to cover through its GUIC mechanism for years to come. Before rider recovery of the revenue requirements stemming from this multi-million dollar investment is approved, the Commission must engage in a broader discussion about the appropriate level of risk reduction should be. Then and only then should a discussion on the formation of metrics, potentially leaks-per-mile or some other metric, commence.

2. Xcel's proposed cost-effectiveness/business practices metrics require a baseline, including historical data and further development of the objectives the metric is driving towards.

Xcel proposed three metrics that focus on cost-effectiveness and good business practices: unit costs of main and service replacements and an estimated versus actual variance explanation metric for its TIMP projects. Cost-effectiveness is a central objective of the GUIC rider statute[149] and it is crucial that the metrics used to determine cost-effectiveness are designed to ensure that GUIC-eligible projects are completed in such a manner.

Two of Xcel's cost-effectiveness metrics measure the unit costs of main and service replacement, with a "detailed explanation" of any cost that exceeds one standard deviation.[150] According to the Company, the objective of these metrics is to "evaluat[e] significant variances for costs."[151] Xcel did not, however, propose to remove costs associated with projects that exceed one standard deviation, nor did it describe why one standard deviation is a reasonable, industry standard measure other than noting that "it is a common means of determining statistical significance."[152] Further, it is unclear what a lagging indicator, or measure of success would be

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[148] Xcel's Initial Petition at Attachment C.
[149] Minn. Stat. § 216B.1635 Subd. 5 (2016).
[150] Xcel's Supplemental Petition at 7–8.
[151] *Id.* at 6.
[152] Xcel's Response to OAG Information Request No. 43 (attached in Appendix A).

for this type of metric from year-to-year. Table 4, below, summarizes the average unit costs and the associated standard deviation for projects completed under these two GUIC projects from 2013 to 2015.

Table 4. Mean + 1 standard deviation for mains and services from 2013 to 2015.[153]

Mean + St. Dev	**2013**	**2014**	**2015**
Mains	$86	$61	$69
Services	$2076	$2,165	$ 1,013

In light of the questions about the data, discussed in the footnote to the table, it is unclear whether any useful information can be gathered from this metric. This is an early example that any metrics that are developed must have both forward-looking and backward-looking compatibility in order to derive any meaningful lessons from the year-to-year trends.

Finally, Xcel has proposed to include an explanation of actual versus estimated cost variances for its TIMP capital projects. This is less a performance metric than it is a method of program evaluation. It is, however, the first time Xcel has generated variance explanations for TIMP project overruns and the OAG does not oppose the gathering of this information in general. If the Commission decides to adopt this "metric," the Company should be required to submit a more detailed explanation than "Scope increased to 2.1 miles due to permit restrictions"[154] in order to justify collection of the cost overrun. Similar to concerns with the unit cost metric, it would be unreasonable to allow recovery of cost overruns simply because the Company has acknowledged the overrun and provided a short explanation—the Commission

[153] Xcel's Supplemental Petition at 7–8; Xcel's Response to OAG IR. No. 38 (attached in Appendix A). One difficulty that has already emerged with this data is that Xcel presented its 2013 and 2014 data in a slightly different format in a response to an OAG information request compared to the data presented in its supplemental petition. Its supplemental petition only included a cost of the mean plus one standard deviation, while the information request response include the mean and the standard deviation separately. A live spreadsheet was not included with this response, but an interpretation was made that the IR responses "Std. deviation" cost was in fact the same as the supplemental petition's "mean + standard deviation" figure.
[154] Xcel's Supplemental Petition at 9.

should take extra care to ensure that the explanation itself demonstrates that the Company has met its burden to show that the costs incurred over what it expected to spend are reasonable and prudent.

3. TIMP number of anomalies repaired appears to be an unreliable metric without additional data, explanation, and context.

Finally, Xcel proposes to include a TIMP metric for the number of gas anomalies repaired each year. The Company stated that the number of repairs are expected to vary from year-to-year, but that eventually the number of repairs will "ultimately reduce."[155] In its supplemental petition, Xcel included data between 2010 and 2015. Four of the six years have zero anomalies repaired while the other two years, 2010 and 2013, have five and twenty-two anomaly repairs, respectively.[156] It may be reasonable to adopt a rolling-average to track a decline in repaired anomalies over time, but it is unclear how long such a period should be. Moreover, it is far from clear that this is the most appropriate metric for measuring progress toward the Company's TIMP objectives. At this time, it would seem to be an unreliable metric given the drastic, seemingly random swings in the number of anomalies repaired by the Company.

4. The reasonableness of Xcel's proposed metrics cannot be determined at this time.

It is too early in the process to tell whether the metrics proposed by Xcel are reasonable and appropriate ways for the Commission to track the Company's, and possibly other utilities' TIMP and DIMP performance. It is possible that some of the metrics proposed by Xcel will ultimately be selected for implementation, but the Commission must first engage in a deliberate process to develop meaningful performance metrics. The next section will cover several

[155] *Id.*
[156] *Id.*

approaches to development of performance metrics, some that are targeted generally to utility regulators and the rest specific to pipeline replacement and integrity management programs.

C. The Commission should consider a more deliberate process utilizing best practices to develop and implement effective performance metrics.

Utilities should not be allowed to determine the rules under which they will be regulated. The same logic applies to performance metrics, which may, in the future, have significant financial implications for utilities. The development of performance metrics should be led by the Commission, not the regulated utility. This section draws from a number of resources to identify best practices and a general structure for performance metric development that the Commission should adopt in this instance. The first two resources are aimed at utility regulators generally, while the second two resources are focused specifically on integrity management best practices and the implementation of performance metrics in that specific context. Full copies of these resources are included in Appendix E.

1. National Regulatory Research Institute, "How Performance Measures Can Improve Regulation."

First, Ken Costello of the NRRI published a study in 2010 called "How Performance Measures Can Improve Regulation."[157] The first full paragraph of the Executive Summary provides a concise distillation of the challenge facing utility regulators:

[157] Ken Costello, The Nat'l Regulatory Research Institute, *How Performance Measures Can Improve Regulation* (Jun. 2010). Attached in Appendix E.

> The challenge for utility regulators is to determine what constitutes a well-performing utility. What do they consider acceptable performance? These are questions that regulators need to address if they are to exploit fully the information contained in performance measures for regulatory actions such as prudence determination and rate setting. *The measurement of performance trends in the absence of a standard, for example, might limit regulatory action to further review, not to a determination of cost recovery*.[158]

Mr. Costello also defines attributes of good performance metrics, which "should be objective, quantifiable, and verifiable."[159] He also discusses the importance of benchmarking as a tool to monitor performance and identify best practices, along with other functions.[160] Finally, he presents a six-step approach to develop a performance initiative:

1. Identify the uses of performance measures;
2. Select utility functional areas for regulatory review;
3. Calculate the performance measures;
4. Compare a utility's performance with a predetermined benchmark;
5. Assess a utility's performance;
6. Take action.[161]

2. Synapse Energy Economics, "Utility Performance Incentive Mechanisms: A Handbook for Regulators."

A second general resource for regulators is a handbook produced by Synapse Energy Economics, Inc. in 2015.[162] It presents a comprehensive manual to assist regulators in properly designing performance metrics. Similar to Mr. Costello, the authors present steps to implementation of metrics:

[158] *Id.* at ii (emphasis added).
[159] *Id.* at 14.
[160] *Id.* at 23.
[161] *Id.* at 27–28.
[162] Melissa Whited, Tim Woolf, & Alice Napoleon, Synapse Energy Economics, Inc., *Utility Performance Incentive Mechanisms: A Handbook for Regulators* (2015). Attached in Appendix E.

2. Articulate goals;
3. Assess current incentives;
4. Identify performance areas that warrant performance metrics;
5. Establish performance metric reporting requirements;
6. Establish performance targets, as needed;
7. Establish penalties and rewards, as needed; and
8. Evaluate, improve, repeat.[163]

The authors also highlight the significant financial incentives that underlie utility capital expenditures, especially in cases where a utility's rate of return is greater than the cost of borrowing. In these instances, according to the authors, "utilities have a financial incentive to maximize their capital expenditures in order to increase rate base and thereby increase profits."[164] Commission staff noted its concern that Xcel may be over-earning in briefing papers for last year's GUIC proceeding.[165] Prudency reviews can, in theory, mitigate some of the capital investment incentives, but in practice, such reviews are burdensome and rare.[166] Further, when major capital expenditures are recovered through a cost tracker, "utilities have little incentive to ensure that those costs are planned and managed as efficiency as possible."[167] The authors also present six design principles for metrics:

1. Tied to the policy goal;
2. Clearly defined;
3. Able to be quantified using reasonably available data;
4. Sufficiently objective and free from external influences;
5. Easily interpreted; and
6. Easily verified.[168]

[163] *Id.* at 5.
[164] *Id.* at 11
[165] *See In the Matter of the Petition of Northern States Power Company for Approval of a 2016 Gas Utility Infrastructure Cost Rider*, Staff Briefing Papers at 39–43 (Jul. 7, 2016) (noting that Commission staff is concerned about how Xcel is able to incur a sizeable, non-GUIC capital budget without the need for a new rate case).
[166] Whited et al., *supra* note 162 at 11.
[167] *Id.* at 13.
[168] *Id.* at 28.

Based on this list of principles, it is easy to see where Xcel's proposed metrics fall short and into the trap of reporting data without conferring useful information.[169] Finally, the authors present design principles to use when identifying performance targets:

1. Tie targets to regulatory goals;
2. Balance costs and benefits;
3. Set realistic targets;
4. Incorporate stakeholder input;
5. Use deadbands to mitigate uncertainty and variability;
6. Use time intervals that allow for long-term, sustainable solutions; and
7. Allow targets to evolve.[170]

With these steps and principles in mind, the next set of reports focus more directly on pipeline replacement efforts.

3. National Regulatory Research Institute, "Balancing Natural Gas Pipeline Safety with Economic Goals."

This NRRI report, as noted above, was referred to in OAG comments in last year's docket and those same concerns and lessons apply this year as well. In particular, Mr. Costello's approach to implementing performance metrics in the context of pipeline replacement efforts is useful: "Regulators should first identify what they wish to accomplish."[171] For example, Mr. Costello provides three examples of metrics that could be set to track utility outcomes with Commission-set objectives:

- To reduce leaks, an appropriate metric is leaks per mile;
- To reduce incidents resulting from maintenance failures, an appropriate metric is the percentage of work orders completed on time; and
- To reduce pipe damage from excavations, an appropriate metric is lines that are correctly located.[172]

[169] *Id.*
[170] *Id.* at 34.
[171] Costello, *supra* note 130 at 15.
[172] *Id.*

The report discusses some of the considerations that apply to programs intended to accelerate the replacement of cast iron and bare steel mains.[173] Mr. Costello notes that replacement of all pre-1960 cast iron and bare steel would be approximately $150 billion; far too expensive to feasibly replace in a politically palatable manner as costs would be approximately $2,100 per customer.[174] Yet, Mr. Costello concedes that PHMSA has encouraged utilities to accelerate the replacement of the riskiest pipe materials. With these two conflicts in mind, he proposes that the key question is *whether utilities should replace old pipes at a faster pace than they have done historically*.[175] If the Commission determines that accelerated replacement activity is appropriate, then there are several additional steps or inquiries that could be useful to ensure that activity is being undertaken in a cost-effective manner, including:

- Determining whether current leak rates require accelerated pipeline replacement;
- Calculation of the lower operating costs that would result from fewer leaks and lower maintenance costs;
- Calculation of the investment costs and comparisons to reference-case investment costs; and
- Calculation of the annual budget for accelerated pipeline replacement.[176]

Each of these inquiries warrants further discussion between the Commission, the Company, and the interested parties. It remains unclear whether the leak rates presented by Xcel require accelerated replacement. In addition, Xcel has never quantified any cost savings that would result from its accelerated replacement program. Other utilities have estimated that accelerated replacement programs generate tremendous cost savings. In Illinois, a utility

[173] *Id.* at 24.
[174] *Id.* at 24–25.
[175] *Id.* at 26.
[176] *Id.* at 27–28.

estimated that its accelerated main replacement efforts would reduce its O&M costs by $244 million over the span of the program.[177]

Finally, Mr. Costello warns that a lack of thorough review can weaken a utility's incentive to control rider-related costs and increases the potential for mission creep, whereby a utility moves additional, unrelated costs into the tracker to hasten recovery of those costs and reduce its risk.[178]

4. PHMSA, "Guidance for Strengthening Pipeline Safety through Rigorous Program Evaluation and Meaningful Metrics."

The federal pipeline safety regulator, PHMSA, released a guidance document in 2014 that provided "guidance on the elements and characteristics of a mature program evaluation approach utilizing processes created to define, collect and analyze meaningful performance metrics."[179] The document did not add any additional legal requirements for pipeline operators like Xcel, but it did clarify and expand upon the agency's expectations regarding existing operator requirements to measure integrity management program effectiveness.[180] As noted above, distribution pipeline operators like Xcel are required to measure and report certain performance metrics to PHMSA in addition to periodic, complete integrity management program evaluations.[181] In addition to the required metrics, the guidance document encourages the development of additional metrics "to enable a better understanding of the program implementation and the performance of specific system or segments within systems."[182] To aid in the development of these additional metrics, PHMSA lists characteristics of effective metrics,

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[177] *Id.* at fn. 79.
[178] *Id.* at 30.
[179] U.S. Dep't of Transportation, Pipeline & Hazardous Materials Safety Admin., *Guidance for Strengthening Pipeline Safety through Rigorous Program Evaluation and Meaningful Metrics* (2014). Attached in Appendix E.
[180] *Id.* at 1.
[181] 49 C.F.R. § 192.1007(e)–(f).
[182] U.S. Dep't of Transportation, Pipeline & Hazardous Materials Safety Admin., *supra* note 179 at 6.

which include: reliability, repeatability, consistency, independence of outside influence, relevance, and comparability, among others.[183] Although the guidance document is intended for internal use by pipeline operators, it can also provide the Commission with useful guidance as it sets out to establish integrity management performance metrics. The document also includes several tables with metrics grouped by application and with leading and lagging indicators identified.[184]

5. The Commission should utilize these resources to develop a process to establish performance metrics in this docket.

These four resources represent different perspectives regarding the development and implementation of performance metrics, from a broad utility regulatory perspective to the perspective of the federal pipeline safety regulator. There are several important lessons that are generated from a review of these resources. First, it is critical that the Commission establish the goals and objectives that it wishes to achieve in the review and approval of cost recovery of utilities' integrity management investments. Setting these objectives is a critical first step in the establishment of meaningful performance metrics to track progress toward the objectives. Second, this particular docket may not be the best forum for discussion of a much broader issue—pipeline safety and cost recovery—that affects other gas utilities operating in the state who are investing hundreds of millions of dollars into integrity management projects. There is a need for performance metrics that are more broadly applicable than the metrics currently proposed by Xcel. Finally, the third lesson is that discussion about performance metrics has been occurring across the utility regulatory sector recently and there are many up-to-date

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[183] *Id.* at 8.
[184] *Id.* at 16–28.

resources available for regulators to begin the process of implementing metrics.[185] Xcel has itself proposed metrics in its most recent, ongoing electric rate case.[186] The establishment of a workable framework to develop performance metrics in the context of gas pipeline safety would not only ensure that the public interest is met by cost-effective investments in safety and appropriate cost recovery of related costs, but it would also generate a working body of knowledge in Minnesota that can be utilized in future proceedings. With these lessons in mind, the next section will discuss specific recommendations for the Commission to consider regarding Xcel's proposed performance metrics.

D. The Commission Should Decline to Adopt Xcel's Proposed Metrics, Require it to File Results from the AGA Questionnaire When Available, and Open a New Docket to Develop Performance Metrics for All Minnesota Gas Utilities' Integrity Management Programs.

The Commission should not approve the performance metrics proposed by Xcel at this time. Before metrics can be implemented, the Commission must first define its objectives for GUIC and other integrity management programs such that metrics can then be tailored to track progress toward the objective or objectives once they are defined. Such an approach is supported by the expert resources summarized above, as is the development of a more deliberative, objective process to establish, implement, and track future performance metrics. In addition, development of metrics must also take into consideration the experiences of other utilities both in Minnesota and across the country, many of which are undertaking pipeline replacement efforts. A better understanding of the similarities and, importantly, the differences between Xcel and other utilities will help to inform the Commission as it develops metrics.

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[185] *See, e.g.*, Herman K. Trabish, *Can Performance-Based Regulation Unlock the Utility of the Future?*, Utility Dive (Mar. 17, 2016), http://www.utilitydive.com/news/can-performance-based-regulation-unlock-the-utility-of-the-future/414651 (last accessed Mar. 18, 2016).

[186] *See In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota*, MPUC Docket No. E002/GR-15-826, Direct Testimony of Aakash H. Chandarana at 55–57 (Nov. 2, 2015).

In response to a concern raised by the OAG regarding the experiences of other states, Xcel has requested that the American Gas Association ("AGA") send out a survey, based on questions submitted by Xcel, to its member utilities to gather information about performance metrics that have been developed for TIMP and DIMP-related projects.[187] Xcel has cautioned that it could take months for the AGA process to generate results and signaled that the discussion of performance metrics could be bifurcated from the 2017 GUIC rider docket.[188] Because of this timetable, and because a more comprehensive view of performance metrics is warranted by the public interest, the Commission should require Xcel to file, in a separate docket, all responses it receives from the AGA and other utilities that result from its SOS request.

Once the Company has made this compliance filing, the Commission should request comments from other parties and, in particular, other utilities. The comments should focus on three issues: reactions to the results of the AGA survey; proposals for the appropriate process to adopt to generate metrics (including whether an independent third party would be useful to guide the process), and insight as to what the appropriate objective or objectives should be for the Commission to adopt with respect to these types of programs. This would be a significant undertaking, but given the level of investment in these programs that has already occurred and that is planned to occur in the coming years, it is imperative that the Commission take a leading role in setting the performance objectives that are in the public interest.

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[187] Xcel's Supplemental Petition at 2. A redlined version of the survey questions that is reflective of modifications suggested by OAG staff can be found in Appendix D.

[188] *See id.* ("We believe that review and discussion about these metrics can continue at any pace that is reasonable for the Commission and parties and need not hinder review of the other components of the Company's 2017 [GUIC] petition.").

It is important, as noted in prior comments, that other Minnesota utilities be included in this discussion.[189] Given the integrity management activity taking place across the state, much of it similar to the activity that Xcel requests recovery of under GUIC, it is relevant to know how Xcel's proposed metrics would apply to other utilities. If the Commission wishes to take a broader, statewide perspective of these important and costly investments, then the metrics it develops must be applicable to all gas utilities' programs, not just to Xcel's.

To start this process, during the preparation of these Comments, the OAG sought information from the other utilities regarding their results under Xcel's proposed metrics as well as any experience the utilities had with the development of performance metrics for their infrastructure replacement activities in each utility's current service quality docket.[190] Two utilities—MERC and Greater Minnesota Gas—responded by noting that the performance metrics are largely inapplicable to their utilities. The other two utilities—CenterPoint and Great Plains—that, as described above, appear to be undergoing significant infrastructure replacement activities, objected to the information requests and provided no information.[191] This reluctance to provide information underscores the need to take a broader look at the infrastructure work being conducted across the state. Simply avoiding the filing of a GUIC rider should not allow other utilities to make massive infrastructure investments without a thorough review or a requirement to report metrics that will allow the Commission to judge how these investments are improving safety and reducing risk for ratepayers across the state.

[189] *In the Matter of the Petition of Northern States Power Company for Approval of a 2016 Gas Utility Infrastructure Cost Rider*, MPUC Docket No. G-002/M-15-808, Comments of the Office of the Attorney General at 15 (Mar. 17, 2016).
[190] The information requests asked utilities to provide results under the metrics proposed by Xcel and to answer the questions contained in the draft AGA survey that is being distributed to gas utilities across the country. The utilities' responses are found in Appendix A.
[191] All four utilities' responses are found in Appendix A.

In this year's GUIC docket, the Commission should take the actions described above in order to begin the process of developing performance metrics for integrity management programs in the state. The next section will present the OAG's analysis of the appropriate ROE to set in this proceeding and will demonstrate why Xcel's proposed ROE is not in the public interest and should be rejected.

III. XCEL'S PROPOSED RETURN ON EQUITY.

The GUIC Statute provides that the rate of return, including the return on equity ("ROE"), for investments recovered through a GUIC Rider should be set at the level approved in the utility's last general rate case, "unless the commission determines that a different rate of return is in the public interest."[192] The Commission has modified the overall rate of return for Xcel's GUIC investments in the last two GUIC proceedings,[193] and also significantly reduced the ROE in last year's GUIC proceeding.[194] Based on this precedent, the primary decision for the Commission in this proceeding is to determine what rate of return, including an ROE, is "in the public interest" as required by Minnesota law.

The analysis conducted by the OAG demonstrates that the ROE applied to Xcel's GUIC investments should be lower than the Company's requested return of 9.50 percent. The analysis presented in this section demonstrates that an ROE of 7.13 percent would be reasonable ROE for investments made under Xcel's 2017 GUIC Rider.

This section will first provide background information regarding the procedural history of ROE in the context of the GUIC Rider, and then briefly discuss the legal standards for utility

[192] Minn. Stat. § 216B.1635 subd. 6 (2016).
[193] *In the Matter of the Petition of Northern States Power Company for Approval of a Gas Utility Infrastructure Cost Rider*, MPUC Docket No. G-002/M-14-336, Order at 13 (Jan. 27, 2015); *In the Matter of the Petition of Northern States Power Company for Approval of a 2016 Gas Utility Infrastructure Cost Rider*, MPUC Docket No. G002/M-15-808, Order at 9 (Aug. 18, 2016).
[194] *In the Matter of the Petition of Northern States Power Company for Approval of a 2016 Gas Utility Infrastructure Cost Rider*, MPUC Docket No. G002/M-15-808, Order at 9 (Aug. 18, 2016).

ROEs. This section will then present the results of the OAG's ROE analysis. Finally, this section will discuss the problems with the ROE analysis conducted by Xcel.

A. Procedural Background.

The Commission has twice determined that the rate of return set in Xcel's most recent natural gas rate case would not be reasonable and set a lower rate of return in an effort to ensure that the rates recovered through the GUIC rider are consistent with the public interest as required by Minnesota law. In the 2015 GUIC Rider docket, both the Department and the OAG recommended reductions to the rate of return. The Commission approved the Department's recommendation to reduce the cost of debt, and ordered Xcel to provide additional ROE information in its next filing in response to the OAG's recommendation to reduce the ROE.[195] For the 2016 GUIC Rider, the Commission continued to use a reduced cost of debt and also reduced the ROE to 9.64 percent.[196]

In this proceeding, Xcel has requested an ROE of 9.50 percent, which is lower than the ROE that was approved in its most recent rate case or the ROE that was approved in last year's GUIC Rider petition. ROE analysis, however, must be based on an evaluation of current market conditions, rather than its comparison to the decisions made based on market conditions in the past. And, the analysis of current market conditions provided below demonstrates that Xcel's request for an ROE of 9.50 percent is unreasonable, and that a lower ROE would be consistent with the public interest as required by Minnesota law.

B. Legal Standard For Utility ROEs.

The GUIC statute provides that "[t]he return on investments for the [GUIC Rider] shall be

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[195] *In the Matter of the Petition of Northern States Power Company for Approval of a Gas Utility Infrastructure Cost Rider*, MPUC Docket No. G-002/M-14-336, Order at 14 (Jan. 27, 2015).
[196] *In the Matter of the Petition of Northern States Power Company for Approval of a 2016 Gas Utility Infrastructure Cost Rider*, MPUC Docket No. G002/M-15-808, Order at 9 (Aug. 18, 2016).

at the level approved by the Commission in the public utility's last general rate case, unless the Commission determines that a different rate of return is in the public interest."[197] In the context of a general rate case, an ROE is set that will allow a utility to earn a "fair and reasonable return upon [its] investment."[198] To be "fair and reasonable," a utility's rate of return should allow the company to maintain its financial integrity, and be comparable to other investments of similar risk. On the other hand, if a utility's rate of return is *higher* than other investments of similar risk, or is *higher* than necessary to maintain the company's financial integrity, then the utility's rates would no longer be just and reasonable.[199] In the context of Xcel's GUIC Rider, these principles mean that the rate of return should be set at a level that is comparable to other investments of similar risk in order to be consistent with the public interest as required by the GUIC Statute.

The following sections will demonstrate that Xcel's request to receive an ROE of 9.50 percent is not in the public interest because the Company's proposal would establish an ROE that is measurably greater than that of investments with comparable risk, as measured by Commission approved methods for estimating ROEs. Instead, the Commission should establish a lower ROE of 7.13 percent.

C. An ROE of 7.13 percent would allow Xcel to earn a fair and reasonable return on its GUIC investments.

The Commission's decisions on utility ROE have established a robust precedent on how an appropriate return should be offered. For many years the Commission has indicated a clear preference for using the Discounted Cash Flow ("DCF") analytical method for estimating utility

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[197] Minn. Stat. § 216B.1635, subd. 6.
[198] Minn. Stat. § 216B.16, subd. 6; 2013 CenterPoint Order at 30; *see also Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944); *Bluefield Waterworks & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923).
[199] Minn. Stat. § 216B.03.

ROEs, with the Capital Asset Pricing Model used as a check on the reasonableness of the DCF results. This section will begin with some background information about the DCF method. This section will then discuss the proxy group used by the OAG, and present the DCF results. This section will then discuss the results of the CAPM analysis, and conclude by summarizing the appropriate ROE for Xcel.

1. Discounted Cash Flow (DCF) Methodology

The Commission has historically relied most heavily on a DCF analytical model in order to determine a fair rate of return on equity.[200] DCF models are based on the theory that the value of an investment is equal to the sum of all future cash flows discounted to the present day. The Constant-Growth DCF model is typically represented by the equation:

$$K = D_1/P_0 + g$$

where K is the estimate of the cost of equity (ROE),

D_1 is the next period's dividend rate,

P_0 is the current stock price,

g is the expected constant growth rate in dividends, and

D_1/P_0 is the next period's dividend yield.

Discounted Cash Flow models are a market-oriented approach requiring the determination of the current yield and appropriate growth rates. The model is based on the premise that dividends are the only income from an investment held in perpetuity. As a result, the value of that investment is the present value of its stream of future cash flows.

The theory behind the DCF concept can be expressed using many different models. These

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[200] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, MPUC Docket No. E-002/GR-13-868, Findings of Fact, Conclusions, and Order at 53 (May 8, 2015).

comments will primarily discuss two models. First, the Constant-Growth DCF model calculates an estimated ROE by applying a constant growth rate to the current observable dividend. Second, the Multi-Stage DCF model calculates an estimated ROE using growth rates that change over time, rather than growth rates that remain constant. For both of these models, it is necessary to create a proxy group of comparable investments.

It is not possible to run the DCF equation on NSPM's investment in GUIC assets directly because NSPM is a division of Xcel Energy, Inc. ("XEI"), which is publically traded under the XEL ticker symbol. NSPM includes both NSPM Electric and NSPM Gas, and the company's investment in these GUIC assets represent a subset of NSPM Gas. Analysts publish Earning Per Share ("EPS") and dividend growth expectations for XEL, but not for NSPM.[201] As a result, it is necessary to analyze a proxy group of risk comparable investments.

There are a few alternatives regarding a DCF analysis when an investment is not a publicly traded security. For example, it is possible to conduct a DCF analysis on the parent company, XEL. For XEL, as of February 10, 2017, a DCF analysis would result in an ROE of 8.78%.[202] But a DCF analysis on a single company may be more sensitive to the randomness of stock prices and to specific analyst growth predictions. Instead, it is generally better to perform a DCF analysis on a comparison or proxy group of investments whose risk profile compares with that of the investment under consideration.

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[201] The Value Line Investment Survey includes dividend growth expectations, while many other analysts offer EPS growth expectations.

[202] 0.0878 = 0.0326 * (1 + 0.5 * 0.0543) + 0.0543

Current yield = 3.26%

Consensus five year EPS Growth = 5.43

Source: zacks.com

2. Proxy Groups

For this proceeding, proxy group analysis started with Xcel's two proxy groups, but subsequent changes were made. Two companies included in Xcel's proxy group should be excluded because they announced significant merger activity after Xcel's petition was filed. WGL Holdings announced on January 25th 2017 that it has entered into an agreement to be acquired by AltaGas Ltd in a $6 billion transaction. DTE Energy announced on September 26th 2016 that it has entered into an agreement to acquire 100 percent of Appalachia Gathering System, and 55 percent of Stonewall Gas Gathering for a combined purchase price of $1.3 billion. WGL Holdings and DTE Energy are thus excluded from the Proxy Groups.

The OAG conducted its DCF analysis on the following proxy groups, summarized below in Table 5:

Table 5. Gas and combined proxy groups used in the OAG's DCF analysis.

Gas Proxy Group:

Company	Ticker
Atmos Energy Corporation	ATO
Chesapeake Utilities Corporation	CPK
New Jersey Resources Corporation	NJR
Northwest Natural Gas Company	NWN
South Jersey Industries, Inc.	SJI
Southwest Gas Corporation	SWX
Spire Inc	SR

Electric & Gas Proxy Group:

Company	Ticker
Ameren Corporation	AEE
Avista Corporation	AVA
CenterPoint Energy, Inc.	CNP
CMS Energy Corporation	CMS
NiSource Inc.	NI
NorthWestern Corporation	NWE
SCANA Corporation	SCG
Vectren Corporation	VVC
Wisconsin Energy Corporation	WEC

The Gas Proxy Group is preferred over the Electric & Gas[203] Proxy Group because the subject of this docket is a Gas Rider and the Gas Proxy Group more closely resembles the risk profile of the company's investment in GUIC assets. The purpose of reviewing the ROE in this case is to determine the proper ROE for investments in natural gas rider assets, so the ROE should be analyzed using a natural gas proxy group. This also more closely parallels how other utilities are treated. For example, CenterPoint Energy Minnesota Gas is a division of a company that owns both electric and natural gas distribution utilities, and the Commission has traditionally set CenterPoint's ROE by reviewing only a natural gas proxy group. This process also tracks the

[203] The company's "Combination Proxy Group" is the "Electric & Gas" Proxy Group.

Commission's decision in Xcel's last electric rate case, where the Commission declined the Company's proposal to use multiple proxy groups and instead set the Company's electric ROE using an electric-only proxy group.[204]

3. Growth Rates

It is possible to project future growth rates by extrapolating from historical trends, but past performance does not necessarily predict future results. Therefore, the estimated growth rates are based on *projected* growth rates. Projected growth rates provided by Yahoo Finance, Zacks Investment Research, and the Value Line Investment Survey are used. Averaging consensus estimates from multiple sources will likely result in double-counting some analyst estimates, so DCF results using the 3-5 year growth estimates from each of these three sources are calculated separately.

Sustained long-run growth in dividends can occur only from the utility's earnings. In other words, companies generally should not pay out dividends that are higher than their long-run profit. But many published forecasts of growth rates are based on shorter term (three to five year) forecasts which may not accurately reflect growth rates over the longer term.

Both constant-growth and multi-stage DCF analyses are performed by (1) using the projected five-year average EPS growth rates for the growth rates in the constant-growth DCF and (2) incorporating more precise, long-term GDP growth and inflation estimates for the multi-stage DCF analysis. The long-term GDP growth estimates are largely based on well-established long-term trends such as the demographic changes associated with the aging population. The five-year growth rates from Yahoo Finance, Zacks Investment Service, and the Value Line

[204] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, MPUC Docket No. E-002/GR-13-868, Findings of Fact, Conclusions, and Order at 60 (May 8, 2015).

Investment Survey are detailed for the Gas and Electric & Gas Proxy Groups in the two tables below:

Table 6. Five-year growth rates for proxy groups from Yahoo Finance, Zacks Investment Service, and the Value Line Investment Survey.

Company	Ticker	Yahoo	Zacks	Value Line
Atmos Energy Corporation	ATO	7.30%	7.00%	6.50%
Chesapeake Utilities Corporation	CPK	5.80%	6.00%	8.50%
New Jersey Resources Corporation	NJR	6.00%	6.50%	3.00%
Northwest Natural Gas Company	NWN	4.00%	4.00%	7.00%
South Jersey Industries, Inc.	SJI	6.00%	10.00%	3.00%
Southwest Gas Corporation	SWX	4.00%	4.45%	7.00%
Spire Inc	SR	4.18%	4.41%	9.00%
Mean		**5.33%**	**6.05%**	**6.29%**
σ		1.19%	1.93%	2.23%
-1 σ		4.14%	4.12%	4.05%
+1 σ		6.51%	7.98%	8.52%

Company	Ticker	Yahoo	Zacks	Value Line
Ameren Corporation	AEE	5.85%	6.50%	6.00%
Avista Corporation	AVA	5.65%	NA	3.00%
CenterPoint Energy, Inc.	CNP	6.63%	5.00%	2.00%
CMS Energy Corporation	CMS	7.26%	6.00%	6.00%
NiSource Inc.	NI	9.20%	7.22%	1.50%
NorthWestern Corporation	NWE	4.34%	5.00%	6.50%
SCANA Corporation	SCG	5.70%	5.67%	4.50%
Vectren Corporation	VVC	4.57%	5.33%	9.00%
Wisconsin Energy Corporation	WEC	6.73%	6.00%	6.00%
Mean		**6.21%**	**5.84%**	**4.94%**
σ		1.39%	0.72%	2.28%
-1 σ		4.82%	5.12%	2.67%
+1 σ		7.60%	6.56%	7.22%

The long-term GDP growth rates are detailed in Appendix F and the inflation estimates are detailed in Appendix G.

4. Dividends and Dividend Yields

The general formula for estimating the expected dividend yield is D_1/P_0, where D_1 is the dividend in the next period and P_0 is the price today. The current annualized dividend is increased by half of the forward-looking EPS growth rate to account for dividend increases that are distributed throughout the year.

P_0 is calculated using the average closing prices over a recent trading period. Since share prices and thus dividend yields can be volatile in the short run, it is best to look at a time period that is not too short since daily capital market aberrations can have a significant P_0 value impact. On the other hand, the time period must be short enough to avoid the influence of outdated historical information that is no longer applicable to the current price. P_0 was calculated by using closing prices over both 30 calendar days and 30 trading days, both of which have been used in previous ROE cases in Minnesota. The ROE differences between using calendar days and using trading days averages approximately one basis point across the twelve mean ROE data points in the OAG's ROE analysis covering the period ending January 31, 2017. 30 calendar days covers every day during the month of January 2017. U.S. Equity Markets were closed on January 2 and January 16, 2017 in observance of the New Year holiday and Martin Luther King Jr. Day, respectively, so the OAG's 30 calendar day period includes the remaining 20 trading days that occurred during January 2017. The 30 trading days ending January 31, 2017 extends back approximately six weeks to mid-December, including each day from December 16, 2016 to January 31, 2017.

Again, the impact of calendar days versus trading days is approximately one basis point in this case and this impact, over time and across proxy groups, will also generally be approximately neutral. When average share prices over the previous four to six weeks have been trending slightly upward, using 30 calendar days rather than 30 trading days will cause the ROE results to be *lower* by a few basis points. When average share prices over the previous four to six weeks have been trending slightly downward, using 30 calendar days rather than 30 trading days will cause the ROE results to be *higher* by a few basis points. The degree of impact depends on the degree to which prices have changed over the previous four to six weeks. If prices have changed significantly, the resulting ROE difference between calculations using trading days and calculations using calendar days will be more substantial. Conversely, if prices have been relatively stable, the impact will be less substantial.

As described above, P_0 is estimated using both 30 calendar days and 30 trading days using closing prices from December 16, 2016 through January 31, 2017. Maximum and minimum prices and the corresponding dividend yields are also provided to illustrate the range of investor expectations during the period. This information is presented in Appendix H along with the results of the Constant-Growth DCF analysis.

5. Results of the Constant-Growth DCF Analysis

The OAG's Constant-Growth DCF results using the consensus growth estimates provided by Yahoo Finance are summarized in Table 7 below and detailed in Appendix H along with the results using the consensus estimates provided by Zacks Investment Service and the estimates provided by the Value Line Investment Survey's analysts.

Table 7. Results of the OAG's constant-growth DCF analysis using growth estimates from Yahoo Finance.

	Low	Mean	High
Gas Proxy Group ROE	6.87%	8.15%	9.41%

6. Multi-Stage DCF Analysis

One of the assumptions of the Constant-Growth DCF model is that growth rates will remain stable indefinitely into the future. While this is a useful simplifying assumption and the Constant-Growth DCF model provides useful information, it is unlikely that growth rates for the companies in the proxy group will remain the same forever. Other, more complex DCF analyses attempt to model the possibility that growth rates will change over time. The Multi-Stage DCF analysis uses multiple[205] growth rates to reflect expected future changes in growth rates, often in several stages. For example, the market expects a gradual inflation increase, and U.S. GDP growth is expected to gradually slow in the future. Multi-Stage DCF analyses incorporate changes such as these into the Return on Equity analysis.

i. Description of the Multi-Stage DCF Method

The Multi-Stage DCF begins with the basic Constant-Growth DCF model. Instead of accepting the assumption that growth rates will remain constant forever, however, the Multi-Stage DCF builds more precise growth estimates into the model. To do so, the Multi-Stage DCF model creates several time periods, which allows different growth rates to be put into the model.

The OAG's Multi-Stage DCF model begins with a "first" time period of five years, in which the model uses the same growth rates as the Constant-Growth DCF model. In other words, the OAG's Multi-Stage DCF model assumes that the Constant-Growth DCF growth rates are correct for the first five years of the analysis. The "second" time period represents years six through ten, and is used as a gradual transition period from the short-term growth projections used for Constant-Growth analysis to the long-term projections that are used in the later stages of the Multi-Stage analysis. The "third" time period represents years eleven through two-hundred, and is based on long-term growth rate projections. The Multi-Stage DCF analysis in this proceeding is based on the real United States GDP forecast provided by the Organization for Economic Cooperation and Development ("OECD").

OECD was established in 1961 and is a non-profit whose mission is "to promote policies that will improve the economic and social well-being of people around the world."[206] Additionally, its mission statement includes the following: "Along the way, we also set out to

[205] This is essentially where the term "Multi-Stage" originates.
[206] Org. for Econ. Cooperation & Dev., *About the OECD*, http://www.oecd.org/about/ (last visited Feb. 28, 2017)

make life harder for the terrorists, tax dodgers, crooked businessmen and others whose actions undermine a fair and open society."[207] The OECD's mission is reasonably well aligned with the Minnesota PUC's mission: "The Minnesota Public Utilities Commission's mission is to create and maintain a regulatory environment that ensures safe, reliable and efficient utility services at fair and reasonable rates." OECD's global GDP forecasts are "based on an assessment of the economic climate in individual countries and the world economy, using a combination of model-based analyses and expert judgement."[208]

One benefit of using OECD projections is that the OECD creates country-specific, year-specific projections for a significant amount of time out into the future. In other words, the OECD publishes specific projections for United States annual GDP growth rates for each year through 2060. The OAG's Multi-Stage DCF analysis uses OECD's annual country level real GDP growth forecasts for the United States extending to the year 2060,[209] when the OECD estimates cease.

Because the OECD projections end in the year 2060, the OAG's Multi-Stage DCF analysis includes a "fourth" time period that uses two different approaches to estimate real GDP growth rates, and balance the problems inherent in using a single point estimate throughout a long time-period with the benefits associated with incorporating future changes in U.S. GDP growth. These approaches are detailed in Appendix I through Appendix N.

The first approach utilizes OECD's 2060 growth estimate of 1.3 percent throughout the remaining years of the model. In other words, the first approach assumes that the OECD's 2060 USA GDP growth estimate for the year 2060 will continue indefinitely after 2060. While this

[207] *Id.*
[208] Org. for Econ. Cooperation & Dev, *GDP Long-Term Forecast*, https://data.oecd.org/gdp/gdp-long-term-forecast.htm#indicator-chart (last visited February 11, 2017).
[209] *Id.* To clarify, while the data is produced by the OECD, the data is a U.S.-specific GDP estimate.

approach is relatively simple, there are some obvious shortcomings in that it is relatively implausible that the United States will have the same growth rate for more than a century.

For the second approach, the growth rate trend beyond 2060 is extrapolated using OECD's growth rates from 2028 through 2060, producing the following formula: $y = 0.0236e^{-0.018x}$. The formula has an R-squared equal to 0.9923, showing that the projections fit the data well.[210] Unadjusted, the formula creates a 0.27 percent gap from OECD's 2060 growth estimate of 1.30 percent to the 2061 formula result of 1.03 percent = $y = 0.0236e^{-0.018*46}$, so the formula is adjusted by adding 0.25 percent to ensure a smooth transition beyond the 2060 growth rate. In other words, this adjustment eliminates a gap, or jump, from the 2060 growth rate to the 2061 growth rate. Then, a gradual transition from the year five growth rates to the year eleven growth rate of 3.97 percent is calculated for years six through ten. The ROE impact of this extrapolation is approximately five basis points. Or, in other words, the difference between assuming that the 2060 growth rate will continue forever and the results of the OAG's extrapolation is relatively small—only five basis points.

The OECD is a superior source for long-term growth estimates compared to other Multi-Stage methods, including Xcel's, for two primary reasons. First, OECD is a well-respected organization with a mission statement that aligns with the Commission's mission and the goal of efficient regulation. Second, OECD publishes country-specific, year-specific estimates. The OAG is not aware of any other source for specific year projections.

To arrive at overall nominal growth rates, inflation expectations are added to the OECD's real growth rates. Long-term inflation expectations are approximately 2.1 percent based on the spread between the 30-year Treasury Bond yield and the 30-year TIPS yield. Inflation

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[210] R-squared is a statistical measurement of how close the data are to the extrapolated regression line. Its values can range from 0.00 to 1.00, with 0.00 indicating a poor fit, and 1.00 indicating a perfect fit.

expectations vary over different time periods, so inflation forecasts based on 10- and 20-year Treasuries in addition to 30-year Treasuries were incorporated.[211] If there were liquid Treasuries with maturities greater than 30 years, the OAG would have incorporated their implied inflation numbers into the analysis as well, but there are none.

ii. The OAG ROE Recommendation is based on the results of the Multi-Stage DCF Analysis.

In this case, the Multi-Stage DCF model, described above, provides a better representation of investor expectations. The mean, mean high, and mean low ROE results for the Gas Proxy Group are in Table 8 below:

Table 8. Mean, mean high, and mean low ROE results for the gas proxy group.

Mean Gas Proxy Group Results			
ROEs	**Low**	**Mean**	**High**
OECD growth	7.08%	7.20%	7.29%
OECD growth with extrapolation beyond 2060	7.01%	7.13%	7.22%

There are several reasons why the mean ROE using the Gas Proxy Group and OECD growth with extrapolation should be used in this proceeding. First, while the constant growth DCF provides useful information, the assumption that growth rates will remain the same forever is not likely to be correct. Second the Gas Proxy Group provides a better representation of the investment risks faced by a Gas LDC. And third, The OECD growth extrapolation provides a better representation of likely growth rates for the years beyond 2060.

These points lead to the 7.13 percent ROE recommendation using the Gas Proxy Group and OECD growth with extrapolation.

[211] Currently the yield curve is relatively flat.

7. Flotation Costs

Flotation costs are the cost of issuing new shares of common stock. They may include (1) an underwriting spread that the investment banks receive by paying the Company one price for shares, and selling the shares to investors at a higher prices; and (2) out-of-pocket expenses including attorney fees, printing costs, and the expense for presentations to investments firms. To the extent that Xcel ever incurred flotation costs, they would actually be incurred by the parent company, XEI.

Xcel requests a flotation cost adjustment of approximately 10 basis points in this docket.

i. The Commission should deny the request for a flotation cost adjustment.

ScottMadden added a 2.926 percent flotation cost based on Docket No. G-002/M-15-808 and Docket No. E-002/GR-13-868.[212] The record in this case does not support a flotation cost adjustment because the company will not incur any flotation costs in the foreseeable future. Xcel has not produced any evidence indicating that they will issue equity at any point in the near future. The Commission has recently denied a flotation cost adjustment based on similar facts in other utility rate proceedings, including the CenterPoint Energy rate case.[213] Following the precedent in the CenterPoint case should lead the Commission to reach the same conclusion in this case.

Other regulatory bodies regularly apply the same principle. In particular, the Federal Energy Regulatory Commission ("FERC") permits "flotation cost adjustments only when the utility demonstrates that a new stock issuance is imminent."[214] The FERC has applied this

[212] Xcel's Initial Petition at Attachment S, page 18 of 132, footnote 28.
[213] *In the Matter of the Application of CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas for Authority to Increase Natural Gas Rates in Minnesota*, MPUC Docket No. G-008/GR-15-424, Findings of Fact, Conclusions, and Order 43–44 (June 3, 2016).
[214] Bangor Hydro-Electric Co et al., Docket No. ER04-157-004, Opinion No. 489, at 31 (2006).

principle in several proceedings to reject flotation cost adjustments where utilities have failed to demonstrate that they will be making issuances during the test year or in the near future.[215] While the Commission is not required to follow FERC's guidance on this issue, FERC's policy comports with the Commission's recent decision in the CenterPoint rate case, and the concerns the Commission has expressed in previous Xcel rate cases. The balance of the Commission's reasoning should lead the Commission to reach the same conclusion in this case as the FERC, and the CenterPoint proceeding, and reject Xcel's request for a flotation cost adjustment.

Denial of a flotation cost adjustment will not have any detrimental effect on Xcel's ability to access capital markets. NSPM can access short term financing through its parent company and appears to have ready access to long-term financing through its own credit facilities. All public equity issuances are handled at the parent company level, rather than at the operating company level. The Company has not produced any evidence to demonstrate that its access to capital markets would change as a result of the flotation cost adjustment.

The Commission should reject the flotation cost adjustment for Xcel's GUIC investments.

8. Capital Asset Pricing Model (CAPM) Analysis

The OAG's CAPM analysis is intended to check on the reasonableness of the DCF analyses performed.

The basic premise of the CAPM is that any risk which is company specific can be eliminated through diversification by holding a portfolio of securities. Therefore, the only risk that matters is the systematic risk of the stock. Systematic risk refers to the risk associated with movements in the macro-economy. This systematic risk is measured by beta, which is a

[215] Williston Basin Interstate Pipeline Co., 104 FERC ¶ 61,036 at P. 51 (2003); Allegheny 65 FERC ¶ 63,026, at 65, 179.

statistical measure that attempts to quantify the non-diversifiable risk of the return on a particular security against the returns inherent in general stock market fluctuation. The formula is expressed as follows:

$k = r_f + \text{beta}\ (r_m - r_f)$

where k is the anticipated rate of return for the stock in question;

r_f is the rate of return on a risk-free asset;

r_m is the anticipated market return; and

$(r_m – r_f)$ is the market risk premium.

To perform a CAPM analysis, it is necessary to determine the return on a risk-free asset, r_f, along with the appropriate beta and the appropriate market rate of return, r_m.

i. Return on Risk Free Assets.

The most widely accepted risk-free investment is the 13-week U.S. Treasury bill. While longer-term Treasury bonds have equivalent default risk to Treasury bills, those longer-term government bonds carry additional risk that the Treasury bills do not. When investors commit their money for longer periods of time, as they do with when purchasing a Treasury bond, they must be compensated for future investment opportunities forgone as well as the potential for future changes in inflation. Investors are compensated for this increased risk by receiving a higher yield on Treasury bonds.

However, there are two problems with using Treasury bill yields as the risk free rate. First, they have been heavily influenced by Federal Reserve policy. For example, since the Fed has acted aggressively over the past several years to keep short-term interest rates low in order to fend off recession, the yield is low. Second, the 13-week Treasury bills do not match the planning horizon of many equity investors. Equity investors generally have an investment horizon beyond 90 days.

For the purposes of the risk-free asset rate of return for the CAPM analysis, the OAG has used the average yields on 10-year, 20-year, and 30-year Treasuries over the period from January 3, 2017 to January 31, 2017.[216] This monthly time period is used again to dampen the impact of daily aberrations. The yields are shown in Table 9 below:

Table 9. 10-year, 20-year, and 30-year yields for Treasuries between January 3, 2017 and January 31, 2017.

	10-Yr	**20-Yr**	**30-Yr**
Treasury Yield	2.43%	2.75%	3.02%

Since the yields on longer term bonds incorporate higher inflation risk premiums, using them in a CAPM analysis may result in an upward bias of the ROE.

ii. Market Rate of Return.

One can choose from a number of market indices to estimate a market rate of return for use in the CAPM formula. Common choices include the S&P 500 Index, the Value Line Composite or the New York Stock Exchange Index. Yahoo Finance no longer provides an estimate for the S&P 500, which had been used by witnesses in the past, so Value Line's estimated 3-5 year price appreciation potential were chosen instead. Value Line's Summary and Index for February 17, 2017 indicated that the growth rate for its market index was 7.79 percent[217] and the dividend yield was approximately 2.0 percent.[218] Using the same assumptions explained earlier, this dividend yield is increased by one half the growth rate of 7.79 percent (0.020 * (1 + 0.5 * 0.0779). This calculation results in a dividend yield of 2.08 percent. Using the yield plus growth methodology, the market rate of return based on Value Line's estimate is

[216] Interest Rate Statistics, U.S. Department of the Treasury, http://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/default.aspx (last visited February 1, 2017).
[217] Value Line Investment Survey: Summary and Index, February 17, 2017.
[218] S&P 500 Dividend Yield, http://www.multpl.com/s-p-500-dividend-yield/ (last visited Feb. 11, 2017).

2.08 percent + 7.79 percent = 9.87 percent. The market rate of return (r_m) equal to 9.87 percent is used in the CAPM calculation.

iii. CAPM and ECAPM Results.

CAPM results are calculated using Betas provided by the same three sources used previously. ECAPM results are calculated using the following formula:

$$k = rf + 0.25(rm - rf) + 0.75\beta\ (rm - rf)$$

ECAPM provides a higher ROE estimate that is intended for use with low Beta stocks, such as utilities. The CAPM and ECAPM results for both Proxy Groups are found in Table 10 below:

Table 10. CAPM and ECAPM results for the gas and combined proxy groups.

Gas Proxy Group: CAPM and ECAPM results

ROEs	**CAPM**			**ECAPM**			**Average**
Beta Source	Yahoo	Zacks	Value Line	Yahoo	Zacks	Value Line	
10-yr Treasury	4.45%	5.34%	7.80%	5.77%	6.43%	8.23%	6.34%
20-yr Treasury	4.68%	5.53%	7.88%	5.95%	6.57%	8.30%	6.49%
30-yr Treasury	4.88%	5.70%	7.96%	6.10%	6.70%	8.36%	6.61%
Average	4.67%	5.53%	7.88%	5.94%	6.57%	8.30%	6.48%

Gas & Electric Proxy Group: CAPM and ECAPM results

ROEs	**CAPM**			**ECAPM**			**Average**
Beta Source	Yahoo	Zacks	Value Line	Yahoo	Zacks	Value Line	
10-yr Treasury	5.18%	5.81%	8.22%	6.31%	6.78%	8.54%	6.80%
20-yr Treasury	5.37%	5.98%	8.29%	6.46%	6.90%	8.59%	6.93%
30-yr Treasury	5.55%	6.13%	8.35%	6.59%	7.02%	8.64%	7.04%
Average	5.36%	5.98%	8.28%	6.45%	6.90%	8.59%	6.93%

According to these CAPM and ECAPM analyses, an investor would require a return of between 4.45 and 8.36 percent based on the Gas Proxy Group and between 5.18 and 8.64 percent based on the Gas & Electric Proxy Group. The CAPM and ECAPM results are lower than DCF results primarily as a result of the low Betas for the stocks included in the proxy group. As a result, the CAPM and ECAPM analyses are used as a check on the reasonableness of the DCF results.

9. Bond Yield Plus Risk Premium Analysis

The OAG did not perform a Bond Yield Plus Risk Premium analysis because "the Commission has historically relied on [the Bond Yield Plus Risk Premium] less heavily [than the

DCF and CAPM models], considering the [Bond Yield Plus Risk Premium] model prone to producing volatile and unreliable outcomes."[219] These outcomes are volatile and unreliable largely because the company's Bond Yield Plus Risk Premium analysis relies on *allowed* ROEs rather than *earned* or *expected* ROEs.

[219] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-13-868, Findings of Fact, Conclusions, and Order 53 (May 8, 2015); *In the Matter of the Application of CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas for Authority to Increase Natural Gas Rates in Minnesota*, MPUC Docket No. G-008/GR-15-424, Findings of Fact, Conclusions, and Order 38 (June 3, 2016).

10. Summary of the OAG's ROE Analysis

The OAG's Multi-Stage DCF model takes into account long-term growth rates that are developed by a respected institution, the OECD, and not tied to unrealistic assumptions about growth rates that plague Xcel's analysis. The 7.13 percent ROE recommendation uses the Gas Proxy Group and OECD growth with extrapolation and excludes flotation costs.

Table 11. Summary of the OAG's ROE Analysis.

Constant-Growth DCF analysis[220]:

	Low	Mean	High
Gas Proxy Group ROE	6.87%	8.15%	9.41%

Multi-Stage DCF analysis:

Mean Gas Proxy Group Results			
ROEs	**Low**	**Mean**	**High**
OECD growth	7.08%	7.20%	7.29%
OECD growth with extrapolation beyond 2060	7.01%	7.13%	7.22%

CAPM and ECAPM for the Gas Proxy Group:

ROEs	**CAPM**			**ECAPM**			**Average**
Beta Source	Yahoo	Zacks	Value Line	Yahoo	Zacks	Value Line	
10-yr Treasury	4.45%	5.34%	7.80%	5.77%	6.43%	8.23%	6.34%
20-yr Treasury	4.68%	5.53%	7.88%	5.95%	6.57%	8.30%	6.49%
30-yr Treasury	4.88%	5.70%	7.96%	6.10%	6.70%	8.36%	6.61%
Average	4.67%	5.53%	7.88%	5.94%	6.57%	8.30%	6.48%

[220] Consensus growth estimates from Yahoo Finance.

D. Xcel's ROE Request Is Not Reasonable.

Xcel's request for an ROE of 9.50 percent is unreasonable for several reasons. First, the Company's ultimate recommendation deviates significantly from the result derived from the DCF methodology that the Commission historically relies on for setting utility ROEs. Second, the analysis that the Company's used for its different ROE methods is unsound. Third, Xcel's 9.50 percent ROE request is unreasonable relative to the 9.20 percent ROE to which it stipulated in its current Electric Rate Case.

1. Xcel's Recommendation Does Not Follow The DCF Methodology.

One of the primary flaws with Xcel's recommendation is that it deviates significantly from the DCF methodology that the Commission has repeatedly indicated it prefers. The Commission has explicitly set utility ROE according to the DCF methodology in every investor-owned rate case since at least 2008 as described in Table 12:

Table 12. Recent Minnesota rate cases where ROEs were set using the Discounted Cash Flow Method.

ROEs Set Using DCF Method[221]

Case	Docket Number
Xcel 2013 Electric	13-868
MERC 2013	13-617
CenterPoint 2013	13-316
Xcel 2012 Electric	12-961
IPL 2010 Electric	10-276
Otter Tail 2010	10-239
MERC 2010	10-977
MERC 2008	08-835
CenterPoint 2008	08-1065
Xcel 2008 Electric	08-1075
Minnesota Power 2008	08-415

Table 12 includes every rate case in which the ROE was not set by a settlement;[222] in each of those cases, the Commission set the ROE using the results of the DCF method. In several of

[221] Findings of Fact, Conclusions, and Order, *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-13-868, at 53 (May 8, 2015); Findings of Fact, Conclusions, and Order, *In the Matter of a Petition by Minnesota Energy Resources Corporation for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G-011/GR-13-617, at 37–41 (Oct. 28, 2014); Findings of Fact, Conclusions, and Order, *In the Matter of an Application by CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G-008/GR-13-316, at 30 (June 9, 2014); Findings of Fact, Conclusions, and Order, *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-12-961, at 11–12 (Sept. 3, 2013); Findings of Fact, Conclusions, and Order, *In the Matter of the Application of Interstate Power and Light Company for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-001/GR-10-276, at 9–11 (Aug. 12, 2011); Findings of Fact, Conclusions, and Order, *In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in Minnesota*, Docket No. E-017/GR-10-239, at 43–44 (Apr. 25, 2011); Findings of Fact, Conclusions, and Order, *In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota*, Docket No. G-007, 011/GR-10-977, at 20 (July 13, 2012); Findings of Fact, Conclusions of Law, and Order, *In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in* Minnesota, Docket No. G-007, 011/GR-08-835, at 10–11 (June 29, 2009); Findings of Fact, Conclusions of Law, and Order, *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-002/GR-08-1075, at 9–11 (Oct. 23, 2009); Findings of Fact, Conclusion of Law, and Order, *In the Matter of an Application by CenterPoint Energy for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G-008/GR-08-1065, at 29–30 (Jan. 11, 2010); Findings of Fact, Conclusions of Law, and Order, *In the Matter of the Application of Minnesota power for Authority to Increase Electric Service Rates in Minnesota*, Docket No. E-015/GR-08-415, at 36 (May 4, 2009).

[222] The ROE in several cases was set by settlement, including Xcel's 2010 electric rate case, Greater Minnesota Gas's 2009 rate case and Minnesota Power's 2010 rate case. *See* Findings of Fact, Conclusions, and Order, *In the*

(Footnote Continued on Next Page)

those cases, the Commission explicitly rejected modifications or departures from the DCF method that were recommended by Administrative Law Judges.[223]

The Commission has explained its decision clearly:

> The Commission rejects the Company's claim that using three models to determine return on equity is superior to relying primarily on the strongest model and using others as validity checks. . . . .
>
> It is not the number of models in the record that ensures a sound decision, but the appropriateness of each model for the purpose at hand, the quality of the data selected as inputs, and the caliber of the analysis applied to the results. Using three models does produce a more detailed record, but it also multiplies the risk of inaccurate inputs and increases the number of points at which subjective judgments are required.
>
> In short, not all models are equally probative, and not every application of the same model is equally probative. The Commission examines the results of every model introduced into the record in every case. In this case the DCF model is the best in the record for determining return on equity.
>
> Here, too, the Commission finds that the transparency and objectivity of the DCF model make it the strongest, most credible model, and that the most reasonable way to proceed is to use its results as a baseline and to use the results of other models to check, inform, and refine those results. . . . [T]he DCF model calls for fewer subjective judgments than the CAPM and Risk Premium models—in fact, two of its three inputs, dividends and market equity prices, are uncontested, publicly reported facts, and the third

(Footnote Continued from Previous Page)
Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota, Docket No. E-002/GR-10-971 (May 14, 2012); Findings of Fact, Conclusions and Order, *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-015/GR-09-1151 (Nov. 2, 2010); Findings of Fact, Conclusions of Law, and Order, *In the Matter of the Application of Greater Minnesota Gas, Inc., for Authority to Increase Rates for Natural Gas Service in the State of Minnesota*, Docket No. G-022/GR-09-962 (Aug. 19, 2010).

[223] *See* Findings of Fact, Conclusions, and Order, *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-13-868, at 53 (May 8, 2015); Findings of Fact, Conclusions, and Order, *In the Matter of a Petition by Minnesota Energy Resources Corporation for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G-011/GR-13-617, at 37–41 (Oct. 28, 2014).

> input, projected growth rates, generally come from a limited number of recognized professional resources.
>
> Further, the Company's three-model method compounds the subjectivity in each of the three models by requiring the analyst to synthesize their results, using subjective criteria. It is much more straightforward to choose the strongest model, use its results as a baseline, and use the results of the other models as additional information.[224]

The Commission has clearly expressed its preference for the single most accurate model, which the Commission has repeatedly indicated is the DCF model.

Instead of following this precedent, Xcel's recommendation deviates significantly from the results of its own DCF analysis. Xcel performed a constant growth DCF analysis on both an electric-and-gas combination proxy group and a gas-only proxy group, and a two stage DCF analysis on the same two proxy groups. The results of *each* of these DCF models, as presented in Tables 13 and 14, demonstrate that Xcel has essentially ignored the results of the DCF methodology in making its request.

Table 13. Results of Xcel's Constant Growth DCF (excluding flotation costs) for the gas and combined proxy groups using 30-, 90-, and 180-day averages.

Xcel's Constant Growth DCF Results Excluding Flotation Costs[225]

Gas Proxy Group	Low ROE	Mean ROE	High ROE
30-Day Average	6.55%	8.66%	10.83%
90-Day Average	6.46%	8.58%	10.75%
180-Day Average	6.57%	8.68%	10.85%

Electric & Gas Proxy Group	Low ROE	Mean ROE	High ROE
30-Day Average	7.96%	8.96%	10.00%
90-Day Average	7.90%	8.90%	9.94%
180-Day Average	8.04%	9.04%	10.08%

[224] *In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota*, Docket No. G-007,011/GR-10-977, Findings of Fact, Conclusions and Order at 20–21 (Jul. 13, 2010).

[225] Xcel's Initial Petition at Attachment S, pages 40 through 45 of 132

Table 14. Xcel's two-stage DCF results (excluding flotation costs) for the gas and the combined proxy groups.

Xcel's Two Stage DCF Results Excluding Flotation Costs [226]

	Low ROE	**Mean ROE**	**High ROE**
Gas Proxy Group	6.53%	8.65%	10.76%
Electric & Gas Proxy Group	8.19%	8.99%	9.90%

Xcel effectively ran eight DCF analyses in this case, and every Mean ROE result is significantly below Xcel's requested ROE. Xcel has abandoned the DCF method approved in previous rate cases. By doing so, Xcel has abandoned nearly a decade of Commission precedent that clearly demonstrates that the DCF model is the preferred method for setting a utility's ROE.

Xcel argues that the constant-growth DCF model is not the most reliable tool in this proceeding because of federal monetary policy and investor expectations for future changes. Specifically, the company argues that "investors currently are willing to pay about twice the premium for the option to sell long-term Government bonds in January 2017 (with an exercise price equal to the current price) than they are willing to pay for the option to buy those bonds." Since the company made these comments on November 1, 2016, the ETF to which the company refers (TLT) has declined from approximately $131 to approximately $119 as of mid-February, 2017, indicating that interest rates have increased.[227] As of February 14, 2017 investors are no longer "willing to pay about twice the premium," rather the relationship is closer to parity, indicating that investors expect that any future increases in interest rates will be relatively benign.[228] As a result, any potential concern over using the DCF model no longer exists.

[226] Xcel's Initial Petition at Attachment S, pages 46 through 51 of 132
[227] *iShares 20+ Year Treasury Bond (TLT)*, http://finance.yahoo.com/quote/TLT/options?p=TLT (last accessed Feb. 14, 2017).
[228] *Id.*

The company's weighted average ROE calculation is concerning. The company included both CAPM and Bond Yield Plus Risk Premium results in its weighted average ROE calculation of 9.57 percent which it presented in Attachment S on page 29. Its 9.50 percent ROE request seems to rely to some extent on this 9.57 percent weighted average ROE calculation. As discussed, the Commission has relied more heavily on the DCF approach than on the other approaches. Specifically, the Commission has relied on CAPM only as a check on DCF results and has not relied on Bond Yield Plus Risk Premium Analyses due to its volatile and unreliable outcomes. The company's choice to include CAPM and Bond Yield Plus Risk Premium results in its weighted average ROE calculation significantly distorts the company's discussion of its recommended 9.50 percent ROE relative to this 9.57 percent weighted average ROE.

2. Xcel's ROE Analysis Is Not Reliable.

In addition to the problems with the Company's proxy groups, the analysis in each of the Company's methods is unsound for several reasons. First, the data contained in the ROE Report is now relatively old. Second, the Company's constant-growth DCF analysis is flawed because the Company uses an extended trading period to calculate the price of the stock. Third, the Company's CAPM results are flawed because the Company did not select an appropriate risk-free rate. And, finally, the Company's Risk Premium method should be disregarded because it is based on unreasonable assumptions.

i. Xcel's ROE Report Is Not Based On Current Data.

Time has passed since the company's initial filing on November 2, 2016. The filing indicates that the data used for its DCF, CAPM, and Risk Premium methods was based on data as of September 30, 2016. That information is now outdated and unreliable, and should not be used for setting the ROE in NSPM-Gas's GUIC Rider. The data used for the OAG's DCF and

CAPM analyses was collected in February 2017. This more-current data presents a much more accurate picture of current investor expectations.

ii. Xcel's Constant-Growth DCF Analysis Using Extended Trading Periods Is Not Reliable.

Xcel conducts its constant-growth DCF analysis using three different trading periods to estimate the price of a stock: 30 days, 90 days, and 180 days. It is not reasonable to use extended trading periods for the DCF methodology. The DCF model, and all of the models used to estimate utility ROEs, are based on the assumption of efficient markets: current stock prices fully reflect all publicly available information. If current stock prices fully reflect all publicly available information, it is not necessary to use an extended trading period to capture more information. In fact, using extended trading periods can capture old information that is not relevant or conflicts with new information. The 30 day trading period properly balances the need to use current information with concerns of volatility to create the most reliable result.

The Commission has recognized this financial principle in the past. In Xcel's 2013 electric rate case, the Commission stated that the "longstanding Minnesota practice" is based on the assumption that "financial markets are efficient such that the current stock prices fully reflect all publicly available information and are therefore the most reliable source of information on investor expectations."[229] The Commission should follow the same principle in this case and limit its consideration to DCF analysis based on the most recent financial information, rather than information that is three or six months old as suggested by Xcel.

[229] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, MPUC Docket No. E-002/GR-13-868, Findings of Fact, Conclusions, and Order 58–60 (May 8, 2015).

iii. Xcel's CAPM Analysis Should Be Rejected Because The Company Did Not Select An Appropriate Risk-Free Rate.

The results of Xcel's CAPM analysis should be disregarded because the company did not select a proper risk-free rate. The Company selects the 30-year Treasury bond as its risk-free rate, when it would be more appropriate to use shorter term bonds. Neither the 30-year nor 20-year Treasury bonds are risk-free. Both have some level of interest rate risk. As of February 15, 2017, however, the 30-year Treasury yield was approximately 30 basis points greater than the 20-year Treasury yield and the 20-year Treasury yield was also approximately 30 basis points greater than the 10-year Treasury yield.[230] Most of this difference is the result of greater risk, and represents a risk premium over and above that of shorter duration bonds. Because the 30-year Treasury bond includes greater interest risk than the 20-year Treasury bond, it is not an appropriate choice for the risk-free rate.

3. Xcel stipulated to a lower ROE in its Electric Rate Case.

Xcel requests a 9.50 percent ROE in this GUIC Rider, but has stipulated to a 9.20 percent ROE in its current Electric rate case. Risks and ROEs of regulated Natural Gas companies in general are lower than the risks and ROEs of regulated Electric companies. Further, investments that Gas companies make through Riders, such as GUIC, carry lower risks than the overall Gas company. Therefore, the ROE award in this case should be well under 9.20 percent.

E. An ROE Of 7.13 Percent Will Provide A Reasonable Return For Xcel's 2017 GUIC Rider.

The Commission has indicated that it prefers to set utility ROEs using DCF results based on 30 day average yields, and that it prefers to set Xcel's ROE using a single proxy group rather

[230] This information was gathered from the website of the United States Department of the Treasury on February 15, 2017. U.S. Dep't of the Treasury, *Resource Center*, https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield (last accessed Feb. 15, 2017).

than blending in a combination group. The OAG's DCF results are the most reasonable in this case. For these reasons, the most reasonable ROE for Xcel in this GUIC rider docket, and the one that is consistent with the public interest, is 7.13 percent.

CONCLUSION

The safety of the natural gas distribution system is an important state priority, and rightfully so. There is no party in this proceeding that would dispute this statement. It is important for the Commission to consider, however, how Xcel's GUIC programs fit into the broader state- and nationwide context of pipeline safety, where many utilities are focusing on removal of materials that are not present in Xcel's distribution system. While it is impossible, at this point, for other parties to make engineering-related judgments related to the projects that Xcel has decided to pursue recovery of in this docket, the Commission requires a much clearer, objective way to determine the level of risk that Xcel removes from its system via GUIC projects. Such a perspective is necessary because of the four figures—$22 million, $50 million, $120 million, and $300 million—presented at the beginning of these Comments. These figures represent the revenues requested this year, the revenues required over the first three years of this initiative, the revenues expected to be required in the coming four years, and the amount of capital Xcel plans to spend in this decade-long investment cycle.

Due to the growing size of GUIC, the growing impact it has on ratepayers, and the specific concerns with the Company's 2017 GUIC petition identified above, the Commission should: establish a 6 percent revenue cap to protect Xcel's ratepayers due to concerns regarding the Company's historical replacement rate in comparison to its GUIC replacement rate, mission creep, and confusing risk assessment methodologies; and require the Company to file a more detailed cost and revenue study or initiate an investigation requiring the Company to demonstrate that its current rates are set at a just and reasonable level.

In addition, the performance metrics proposed by the Company in its supplemental petition should not be adopted at this time. The proposed metrics are the result of a process that was led by the Company, not the Commission. Further, the given the significant activity that other Minnesota utilities are undertaking under pipeline integrity management programs and, especially given the objection of several utilities to provide relevant information, indicates that any process to develop performance metrics for integrity management programs should include other Minnesota gas utilities and other interested parties. As such, the Commission should require the Company to file results from its AGA information request and initiate a separate docket to begin a broader discussion on the development of performance metrics with Xcel, other gas utilities, and other interested parties.

Finally, the Company's proposed return on equity of 9.50 percent is not reasonable and should not be adopted in this docket. The Multi-Stage DCF analysis proposed in these Comments, using OECD growth data and a more appropriate proxy group, results in an ROE that is in the public interest. The Commission should thus set the ROE in this proceeding at 7.13 percent.

Dated: March 1, 2017

Respectfully submitted,

LORI SWANSON
Attorney General
State of Minnesota

s/ **Joseph A. Dammel**

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March 1, 2017

Mr. Daniel Wolf, Executive Secretary
Minnesota Public Utilities Commission
121 Seventh Place East, Suite 350
St. Paul, MN 55101-2147

RE: ***In the Matter of the Petition of Xcel Energy for Approval of a Gas Utility Infrastructure Cost Rider Compliance Filing, and Annual Report for 2017***
Docket No. G002/M-16-891

Dear Mr. Wolf:

Enclosed and e-filed in the above-referenced matter please find *Initial Comments of the Office of the Attorney General*.

By copy of this letter, all parties have been served. An Affidavit of Service is also enclosed.

Sincerely,

s/ **Joseph A. Dammel**
JOSEPH A. DAMMEL
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Enclosures

AFFIDAVIT OF SERVICE

RE: ***In the Matter of the Petition of Xcel Energy for Approval of a Gas Utility Infrastructure Cost Rider Compliance Filing, and Annual Report for 2017***
Docket No. G002/M-16-891

STATE OF MINNESOTA)
) ss.
COUNTY OF RAMSEY)

I, RACHAEL BERNARDINI, hereby state that on this 1st day of March, 2017, I filed with eDockets ***Initial Comments of the Office of the Attorney General*** and served the same upon all parties listed on the attached service list by email, and/or United States Mail with postage prepaid, and deposited the same in a U.S. Post Office mail receptacle in the City of St. Paul, Minnesota.

s/ **Rachael Bernardini**
RACHAEL BERNARDINI

Subscribed and sworn to before me
this 1st day of March, 2017.

*s/***Patricia Jotblad**
Notary Public

My Commission expires: January 31, 2020

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